



US 20090038799A1

(19) **United States**(12) **Patent Application Publication****Garcia-Lopez de Victoria et al.**(10) **Pub. No.: US 2009/0038799 A1**(43) **Pub. Date: Feb. 12, 2009**(54) **SYSTEM, METHOD, AND APPARATUS FOR
COMBINED FRACTURING TREATMENT
AND SCALE INHIBITION****Related U.S. Application Data**

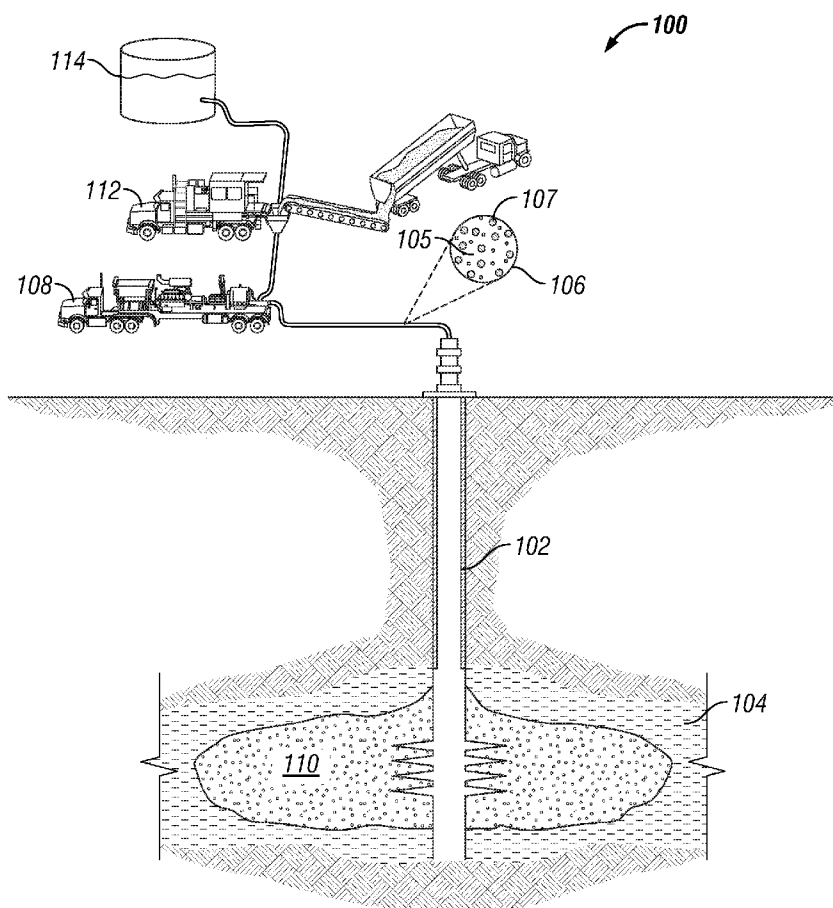
(60) Provisional application No. 60/952,382, filed on Jul. 27, 2007.

Publication Classification(51) **Int. Cl.**
E21B 43/267 (2006.01)(52) **U.S. Cl.** **166/280.2; 507/237; 166/177.5**(57) **ABSTRACT**

A treatment fluid for a subterranean formation includes a carrier fluid and an amount of particles including a granular scale inhibitor. The carrier fluid includes a hydratable gel fluid, a crosslinked gel fluid, an acid-based fluid, an oil-based fluid, and/or a visco-elastic surfactant. The particles include a proppant impregnated with the scale inhibitor, a solid particle formed largely from the scale inhibitor, or both. The proppant includes scale inhibitor adsorbed on porous surfaces within the proppant, and/or a porous proppant with scale inhibitor embedded in the bulk porosity of the proppant. The scale inhibitor is present in an amount between about 1% and 5% of a total weight of particles. The particles include scale inhibitor at a sufficient concentration and dissolution rate to provide acceptable scale inhibitor concentrations in produced fluids for production volumes exceeding 500 pore volumes.

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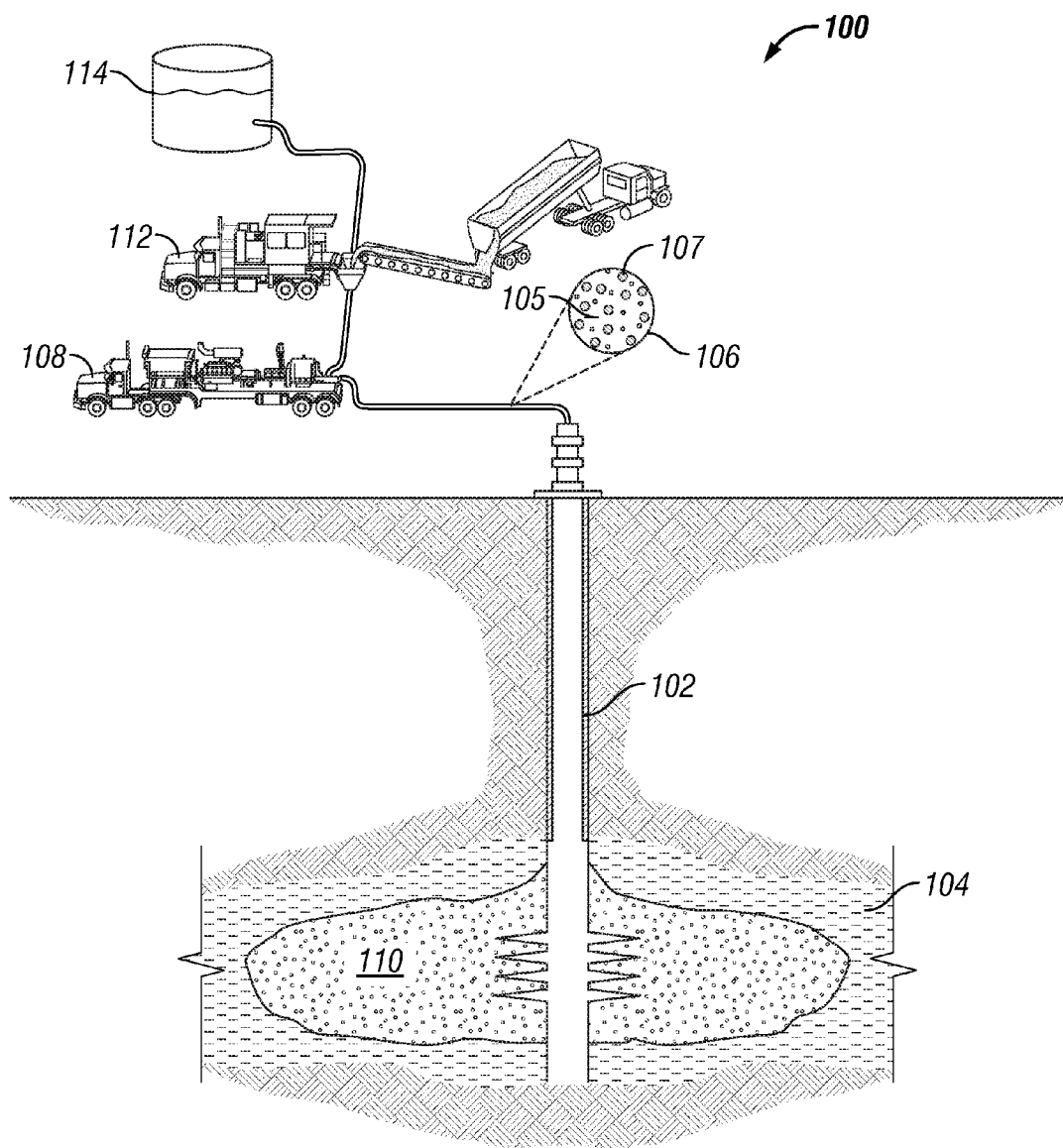


FIG. 1

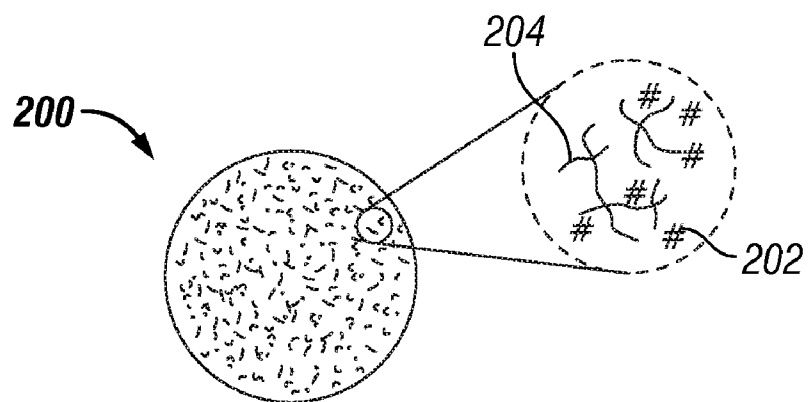


FIG. 2A

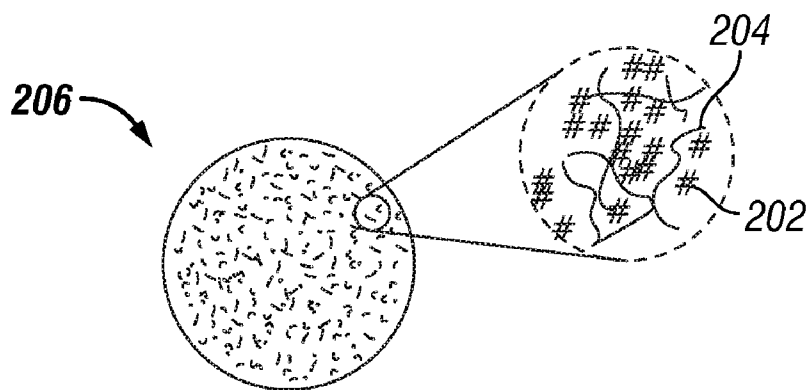


FIG. 2B

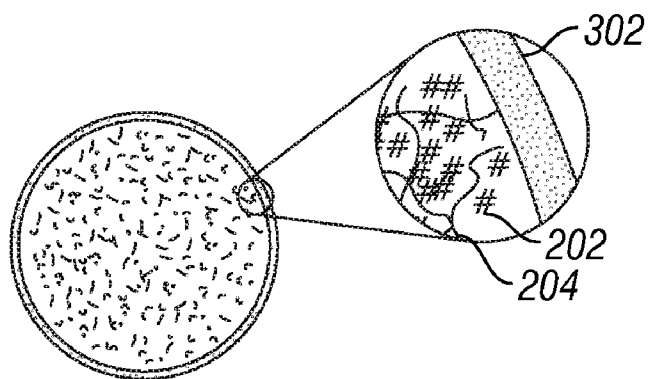


FIG. 3

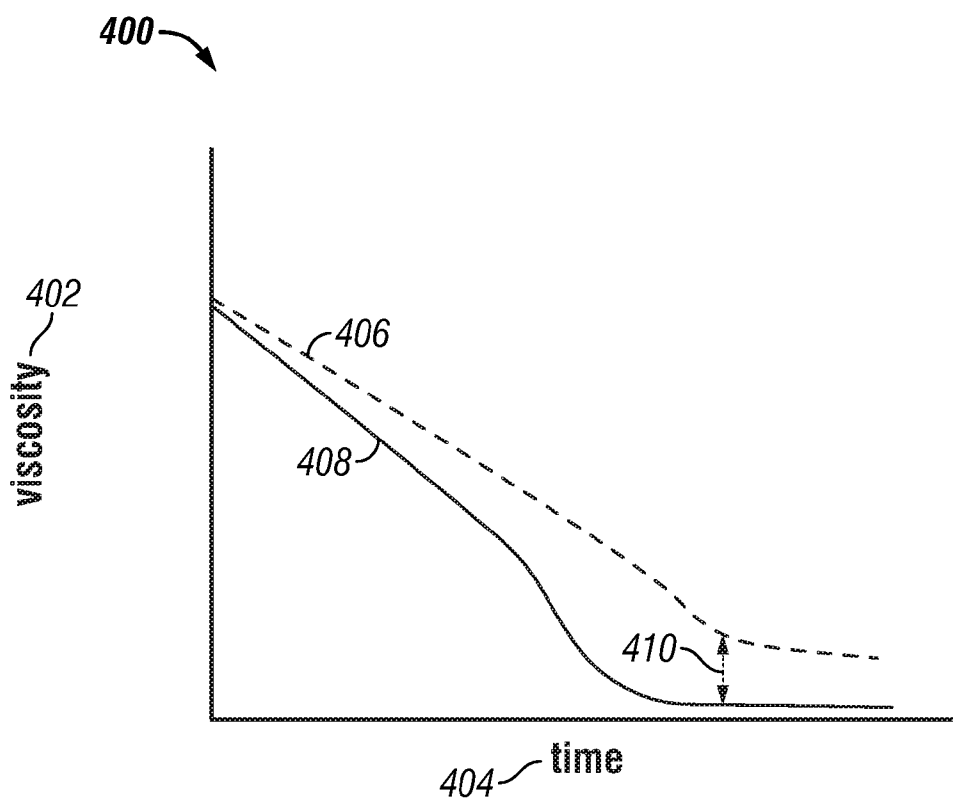


FIG. 4

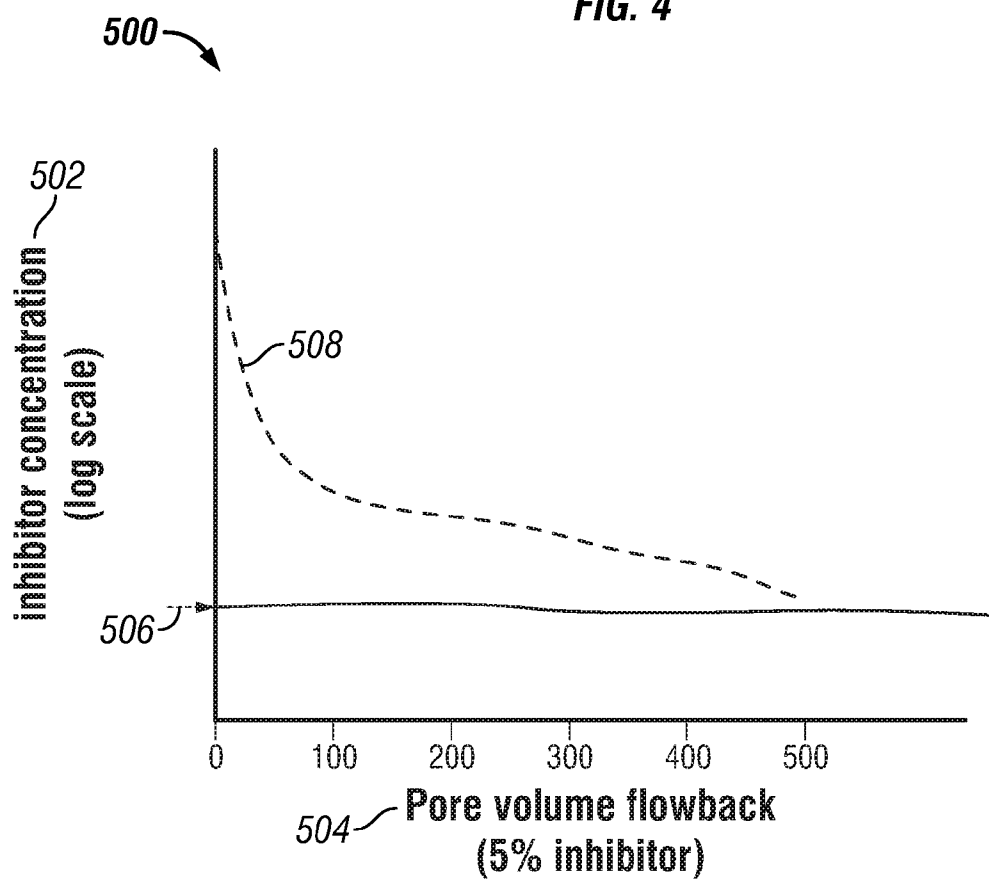
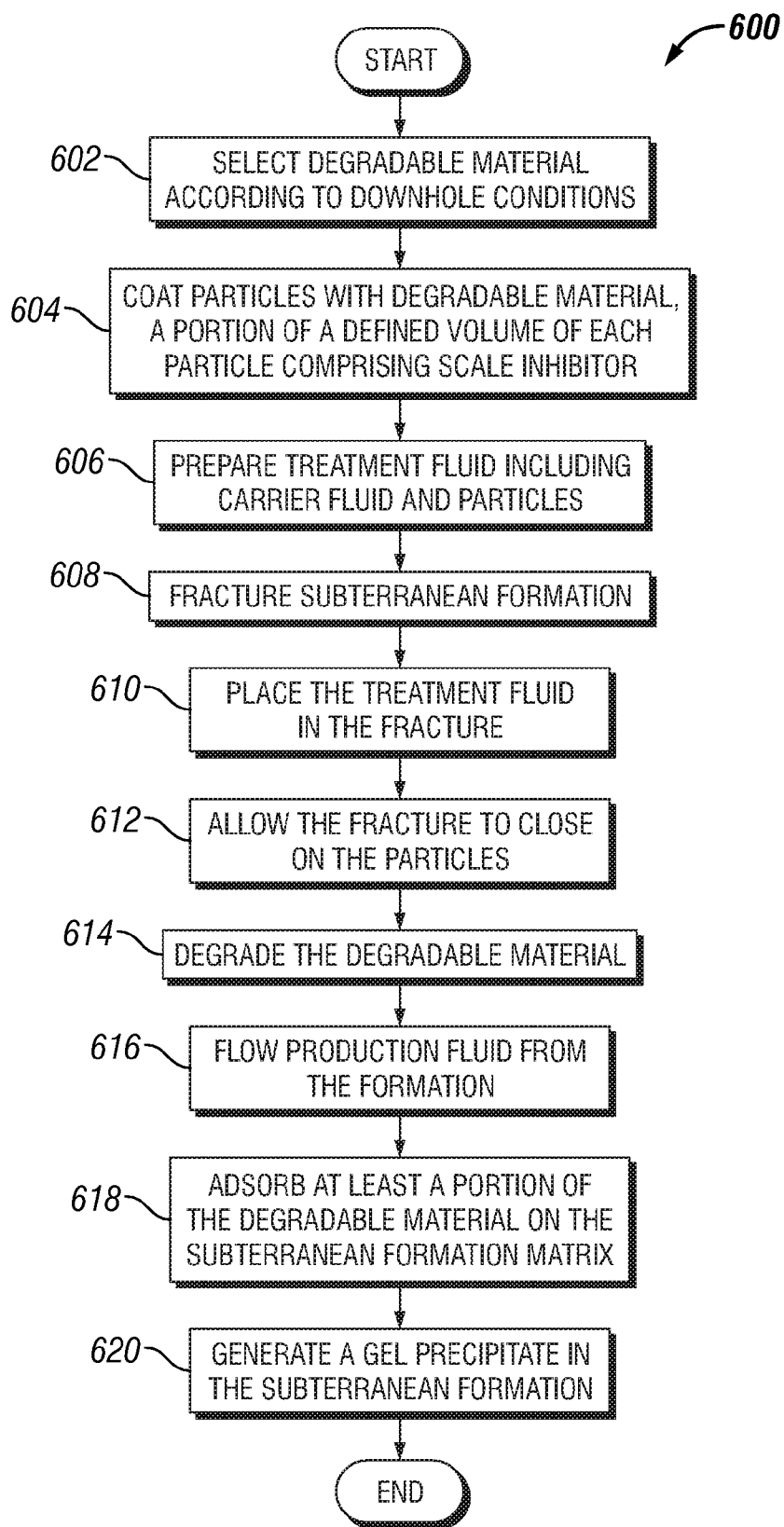


FIG. 5

**FIG. 6**

SYSTEM, METHOD, AND APPARATUS FOR COMBINED FRACTURING TREATMENT AND SCALE INHIBITION

CROSS REFERENCE

[0001] The present application claims the benefit of U.S. Patent Provisional Application No. 60/952,382, entitled "Fracture treatment fluid including a granular scale inhibitor composition and method of use", filed Jul. 27, 2007, which is incorporated herein by reference in its entirety.

FIELD OF THE INVENTION

[0002] The present invention relates to inhibiting scale formation in wells, and more particularly but not exclusively relates to inhibiting scale formation in hydraulically fractured fluid producing wells.

BACKGROUND

[0003] Scale formation in fluid-producing wells can reduce productivity of the well or even stop production completely. Scale formation chemistry is generally understood, and conventional scale inhibition treatments are known in the art. One conventional scale inhibition method consists of injecting a fluid including a scale inhibitor chemical into a formation, and flushing the chemical away from the wellbore with an amount of follow-up flushing fluid, where the chemical may be designed to adsorb to formation particle surfaces. The scale inhibitor chemical may be included in a water-based or oil-based fluid. One conventional scale treatment involves coating particles with resin, and coating the resin with scale inhibitor to prevent the resin coated particles from sticking together before treatment is completed, while the scale inhibitor coating provides some scale inhibition after the treatment. Unfortunately, currently available scale inhibition treatments suffer from a few drawbacks. For example, currently available scale inhibition treatments do not inhibit scale for long periods of time and therefore require repeated application. In high flow areas of a well, for example in an induced hydraulic fracture, the scale inhibitor is removed by producing fluid quickly reducing the effectiveness of the treatment. Also, the available concentration of scale inhibitor declines rapidly after initial treatment, and therefore the scale inhibition procedure must be repeated often or overdesigned with initial concentrations much higher than required to inhibit scale. Accordingly, there is a demand for further improvements in this area of technology.

SUMMARY

[0004] One embodiment is a unique treatment fluid for inhibiting scale formation in a producing well. Other embodiments include unique systems and methods to control scale formation. Further embodiments, forms, objects, features, advantages, aspects, and benefits shall become apparent from the following description and drawings.

BRIEF DESCRIPTION OF THE FIGURES

[0005] FIG. 1 is a schematic diagram of a system for scale inhibition.

[0006] FIG. 2A is a schematic illustration of a particle.

[0007] FIG. 2B is a schematic illustration of a particle.

[0008] FIG. 3 is a schematic illustration of a coated particle.

[0009] FIG. 4 is an illustration of a fluid breaker profile.

[0010] FIG. 5 is an illustration of a scale inhibitor concentration versus production fluid flowback.

[0011] FIG. 6 is a schematic flow diagram of a procedure for scale inhibition.

DESCRIPTION OF THE ILLUSTRATIVE EMBODIMENTS

[0012] For the purposes of promoting an understanding of the principles of the invention, reference will now be made to the embodiments illustrated in the drawings and specific language will be used to describe the same. It will nevertheless be understood that no limitation of the scope of the invention is thereby intended, and any alterations and further modifications in the illustrated embodiments, and any further applications of the principles of the invention as illustrated therein as would normally occur to one skilled in the art to which the invention relates are contemplated and protected.

[0013] FIG. 1 is a schematic diagram of a system 100 for scale inhibition. The system 100 includes a wellbore 102 intersecting a subterranean formation 104. The subterranean formation 104 may be a hydrocarbon bearing formation, or any other formation where fracturing may be utilized and inhibiting scale formation may be desirable. In certain embodiments, the subterranean formation 104 may be for an injection well (such as for enhanced recovery or for storage or disposal) or in a production well for other fluids such as carbon dioxide or water. In certain embodiments, the system 100 includes an amount of treatment fluid 106. The treatment fluid 106 includes a carrier fluid 105, an amount of particles 107 where each particle defines a volume and includes a scale inhibitor comprising at least a part of the defined volume. The defined volume includes the particle, but does not include the surface of the particle.

[0014] In certain embodiments, the amount of particles 107 include granular scale inhibitor particles 107 comprising at least partially, or even completely, solid scale inhibitor. In certain embodiments, the amount of particles 107 include proppant particles having a porosity—for example porous ceramic proppant particles—and having scale inhibitor stored within the porosity. In certain further embodiments, the scale inhibitor stored within the proppant porosity can be scale inhibitor adsorbed to internal surfaces of the proppant, and/or scale inhibitor packed into the bulk porosity of the proppant. In certain embodiments, the proppant may be impregnated with the scale inhibitor. In certain further embodiments, the treatment fluid includes scale inhibitor as granular scale inhibitor particles and further includes scale inhibitor within a porous proppant particle.

[0015] The storage of scale inhibitor within the defined volume of solid particles rather than within the liquid phase of the treatment fluid allows for a greater concentration of scale inhibitor and a configurable dispersion or dissolution time for the scale inhibitor. Further, the storage of scale inhibitor within the defined volume of solid particles allows for a greater concentration and a configurable dispersion or dissolution time for the scale inhibitor relative to a surface coating of scale inhibitor, including dispersion times that can be much greater than the dispersion times of a surface coated scale inhibitor. In certain embodiments, additional scale inhibitor may be included in the liquid phase of the treatment fluid and/or on the surface of or as a coating for the particles 107.

[0016] In certain embodiments, the solid granular scale inhibitors particles include mixtures, blends, and/or filled polymers and the like and may be manufactured in various

solid shapes, including, but not limited to fibers, beads, films, ribbons and platelets. The scale inhibitor may be coated to promote adsorption to surfaces or to slow dissolution. Non-limiting examples of coatings include polycaprolate (a copolymer of glycolide and epsilon-caprolactone), and calcium stearate, both of which are hydrophobic. The term "coating" as used herein may refer to encapsulation or simply to changing the surface by chemical reaction or by forming or adding a thin film of another material. In certain further embodiments, the coating includes a material that degrades in contact with a hydrocarbon, a material that degrades at a downhole temperature, and/or a material that degrades in a formation brine.

[0017] The appropriate combination of carrier fluid, scale inhibitor and proppant may be selected readily from available materials. The rate of dissolution of the granular scale inhibitor is governed by factors such as the choice of material, the ratio of materials, the particle size, calcining and coating of the solid material, the fluids and temperature in the subterranean formation **104**, and may readily and easily be determined by routine measurements. In certain embodiments, the scale inhibitor comprises a particle size greater than about 25 microns (μm). In certain embodiments, the scale inhibitor is included on a proppant, and the proppant has a size at least equal to a 100-mesh proppant. The embodiments provided are exemplary only, and various embodiments are contemplated, with scale inhibitors included on particles smaller or larger than those listed.

[0018] A scale inhibitor or inhibitors should be selected to be compatible with the function of other components of the treatment fluid **106**. The granular scale inhibitor and/or proppant including inhibitor may be part of a suspension in a treatment fluid in the wellbore, in the perforations, in a fracture **110**, as a component of a filter cake on the walls of a wellbore **102** or of a fracture **110**, and/or in the pores of the subterranean formation **104**. In certain embodiments, the subterranean formation **104** may be carbonate (including limestone and/or dolomite) or sandstone, although other formations benefitting from scale inhibition are also contemplated.

[0019] In certain embodiments, the granular scale inhibitor is structured to degrade over time. The particle size of the granular scale inhibitor may be almost any size transportable by the carrier fluid. Governing factors for size selection include at least a) the capability of equipment (e.g. a pump **108** and blender **112**), b) the width of the fracture **110** generated, and c) the desired rate and time of particle degradation. The rate of degradation can readily be determined by routine measurements in a laboratory with a given fluid at a given temperature. In certain embodiments, the particles sizes of the granular scale inhibitor are selected to be similar to a proppant size and/or a fluid loss additive size. In certain embodiments, the granular scale inhibitor includes the scale inhibitor and one or more other particulate materials.

[0020] In certain embodiments, additives are included as ordinarily used in oilfield treatment fluids **106**. Additives should be checked for compatibility with the scale inhibitor (in granular or within proppant form) and for interference with the performance of the scale inhibitor. If an additive includes a component (such as a buffer or a viscosifier) that may interact with the scale inhibitor, then either the amount or nature of the scale inhibitor, or the amount or nature of the interfering or interfered-with component may be adjusted to

compensate for the interaction. Routine measurements and fluid tests in a laboratory may quantify additive-inhibitor interactions.

[0021] In certain embodiments, the scale inhibitor is included in an amount between about 1% and 5% by weight of a total amount of particles **107**. For example, in a fracture treatment where the particles **107** include 35,000 pounds of proppant with porosity or other features capable of storing scale inhibitor within the defined volume of the proppant, the amount of scale inhibitor in the proppant is between about 350 and 1,750 pounds. In certain embodiments, the scale inhibitor may be included at lower than 1% or higher than 5%.

[0022] In certain embodiments, the system **100** further includes a pump **108** that fractures the subterranean formation, and places the treatment fluid **106** in the fracture **110**. The pump **108** may receive treatment fluid **106** from a blender **112** that generates various fracture fluids including the treatment fluid **106**. In certain embodiments, the treatment fluid **106** is utilized at one or more stages of a fracturing treatment. For example, the fracture treatment may utilize a pad fluid comprising a viscosified fluid that has no particulates, followed by the treatment fluid **106** including particulates, and concluding with a flush that has no particulates. However, the treatment fluid **106** may be utilized in any or all stages of a fracture treatment.

[0023] In certain embodiments, the carrier fluid **105** may be stored in a tank **114** and added to the treatment fluid **106** during operations. In certain embodiments, the carrier fluid **105** may be generated at the blender **112** from a base fluid in the tank **114**. The carrier fluid **105** includes any base fluid known in the art that can be utilized to carry particulates, and the carrier fluid **105** typically includes a viscosifier. For example, the carrier fluid **105** may include a hydratable gel-based fluid, a cross-linked hydratable gel-based fluid, an oil-based fluid, a visco-elastic surfactant (VES) fluid, and an acid-based fluid.

[0024] The following exemplary viscosifiers are disclosed as illustrative only. Some nonlimiting examples of suitable polymers include guar gums, high-molecular weight polysaccharides composed of mannose and galactose sugars, or guar derivatives such as hydropropyl guar (HPG), carboxymethyl guar (CMG), and carboxymethylhydroxypropyl guar (CMHPG). Cellulose derivatives such as hydroxyethylcellulose (HEC) or hydroxypropylcellulose (HPC) and carboxymethylhydroxyethylcellulose (CMHEC) may also be used. Any useful polymer may be used in either crosslinked form, or without crosslinker in linear form. Xanthan, diutan, and scleroglucan have been shown to be useful as viscosifying agents. Synthetic polymers such as polyacrylamide and polyacrylate polymers and copolymers may be used in high-temperature applications. In certain embodiments, the carrier fluid **105** includes a highly salt-tolerant fluid, including a fluid that viscosifies in high salinity and that breaks in high salinity.

[0025] Nonlimiting examples of suitable viscoelastic surfactants (VES) include cationic surfactants, anionic surfactants, zwitterionic surfactants, amphoteric surfactants, non-ionic surfactants, and combinations thereof. In certain embodiments, the VES fluid may include additional friction-reducing polymers. In certain embodiments, the carrier fluid **105** includes a charged polymer in the presence of a surfactant having a charge that is opposite to that of the charged polymer, the surfactant being capable of forming an ion-pair association with the polymer resulting in a hydrophobically modified polymer having a plurality of hydrophobic groups and

enhanced viscosity, as described in published application U.S. 20040209780A1, Harris et. al.

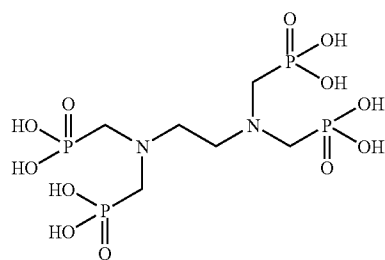
[0026] In certain embodiments, the viscosifier is a water-dispersible, linear, nonionic, hydroxyalkyl galactomannan polymer or a substituted hydroxyalkyl galactomannan polymer. Examples of useful hydroxyalkyl galactomannan polymers include, but are not limited to, hydroxy-C1-C4-alkyl galactomannans, such as hydroxy-C1-C4-alkyl guar. Preferred examples of such hydroxyalkyl guar include hydroxyethyl guar (HE guar), hydroxypropyl guar (HP guar), and hydroxybutyl guar (HB guar), and mixed C2-C4, C2/C3, C3/C4, or C2/C4 hydroxyalkyl guar. Hydroxymethyl groups can also be present in any of these.

[0027] When incorporated, the polymer based viscosifier may be present at any suitable concentration. In various embodiments hereof, the gelling agent can be present in an amount of from about 10 to less than about 60 pounds per thousand gallons of liquid phase, or from about 15 to less than about 40 pounds per thousand gallons, from about 15 to about 35 pounds per thousand gallons, 15 to about 25 pounds per thousand gallons, or even from about 17 to about 22 pounds per thousand gallons. Generally, the gelling agent can be present in an amount of from about 10 to less than about 50 pounds per thousand gallons of liquid phase, with a lower limit of polymer being no less than about 10, 11, 12, 13, 14, 15, 16, 17, 18, or 19 pounds per thousand gallons of the liquid phase, and the upper limit being less than about 50 pounds per thousand gallons, no greater than 59, 54, 49, 44, 39, 34, 30, 29, 28, 27, 26, 25, 24, 23, 22, 21, or 20 pounds per thousand gallons of the liquid phase. In some embodiments, the polymers can be present in an amount of about 20 pounds per thousand gallons. Hydroxypropyl guar, carboxymethyl hydroxypropyl guar, carboxymethyl guar, cationic functional guar, guar or mixtures thereof, are preferred polymers for use

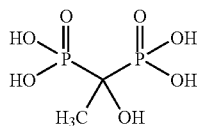
herein as a gelling agent. Fluids incorporating polymer based viscosifiers may have any suitable viscosity, preferably a viscosity value of about 50 mPa-s or greater at a shear rate of about 100 s^{-1} at treatment temperature, more preferably about 75 mPa-s or greater at a shear rate of about 100 s^{-1} , and even more preferably about 100 mPa-s or greater.

[0028] In certain embodiments, the treatment fluid **106** includes an activator present in an amount between about 0.1% and 50% by weight of the scale inhibitor. In certain further embodiments, the activator reacts with a fraction of the scale inhibitor to form a gel precipitate in the fracture **110** and/or subterranean formation **104**. The gel precipitate slowly dissolves in produced fluids from the subterranean formation **104**, releasing scale inhibitor into the produced fluid. In certain embodiments, the activator includes a divalent ion, an ionic salt, and/or calcium chloride. In certain embodiments, the scale inhibitor includes a chemical that adsorbs to the matrix of the subterranean formation **104**, with or without the addition of an activator.

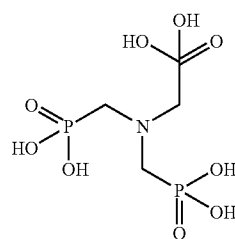
[0029] In certain embodiments, the scale inhibitor includes a compound that inhibits the formation of carbonate and/or phosphate scales. In certain embodiments, the scale inhibitor includes a compound including sulfonates, phosphate esters, phosphonates, phosphonate polymers, polyacrylates and polymethacrylates, polycarboxylates, and phosphorous containing polycarboxylates, and/or phosphonic acid derivatives. In certain embodiments, the scale inhibitor includes a compound including phosphino-polyacrylates and/or phosphonic acid ethylene diamine derivatives. In certain embodiments, the scale inhibitor includes a compound including phosphonic acid[1,2-ethanediylbis [nitrilobis(methylene)]]tetrakis, calcium salts thereof, and/or sodium salts thereof. In certain embodiments, the scale inhibitor includes a compound represented by at least one of the following structures:



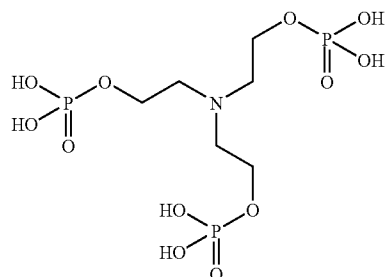
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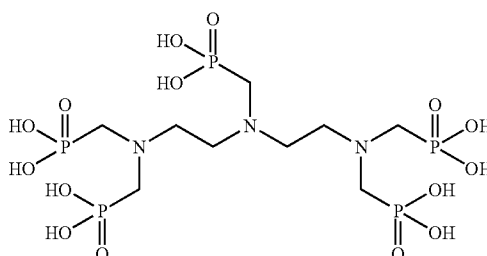
HEDP



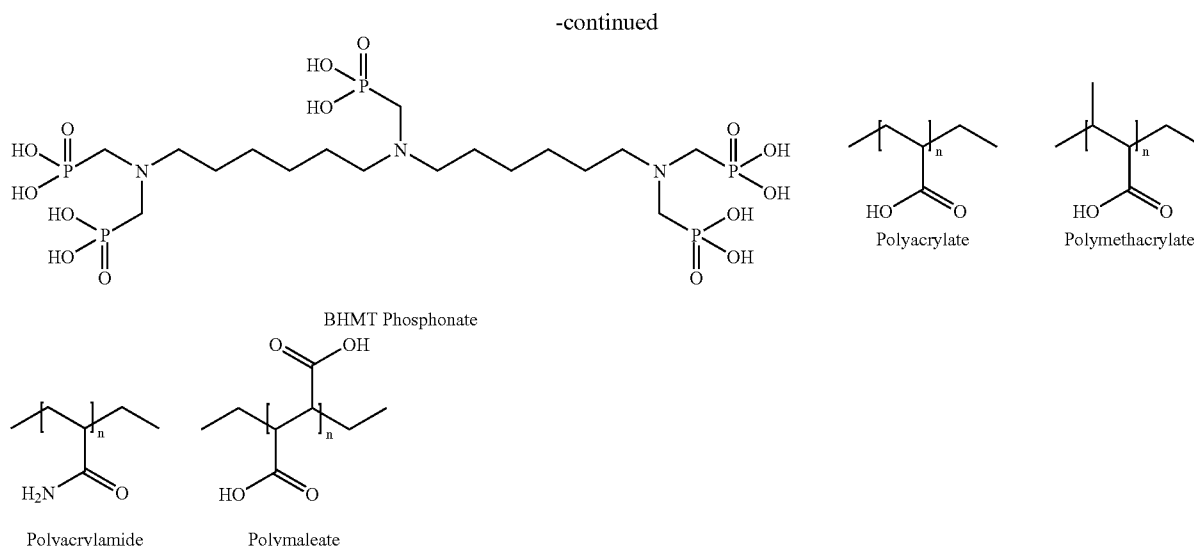
ATMP



TEA Phosphate Ester



DETA Phosphonate



[0030] FIG. 2A is a schematic illustration of a particle 200. The particle 200 is a porous proppant particle including scale inhibitor 202 adsorbed to internal surfaces of the proppant matrix 204. An embodiment such as that illustrated in FIG. 2A allows high concentrations of scale inhibitor 202 to be embedded in the subterranean formation 104 and/or fracture 110 with a configurable dissolution rate to allow the scale inhibitor 202 release to occur over extended periods. Examples of some of the controllable parameters to configure the concentration and dissolution rate of the scale inhibitor 202 include the selection of proppant materials, scale inhibitor 202 compositions, proppant porosity percentage and pore size.

[0031] FIG. 2B is a schematic illustration of a particle 206. The particle 206 is a porous proppant particle including scale inhibitor 202 filling the bulk porosity of the proppant. An embodiment such as that illustrated in FIG. 2A allows high concentrations of scale inhibitor 202 to be embedded in the subterranean formation 104 and/or fracture 110 with a configurable dissolution rate to allow the scale inhibitor 202 release to occur over extended periods. Examples of some of the controllable parameters to configure the concentration and dissolution rate of the scale inhibitor 202 include the selection of proppant materials, scale inhibitor 202 compositions, proppant porosity percentage and pore size. In certain embodiments, the scale inhibitor 202 may fill the bulk porosity and be adsorbed on the proppant matrix 204.

[0032] FIG. 3 is a schematic illustration of a coated particle 300. FIG. 3 illustrates the coated particle 300 as a coated proppant particle, but the coated particle 300 in certain embodiments includes a coated granular scale inhibitor. In certain embodiments, the granulated scale inhibitor and/or proppant including scale inhibitor includes a coating 302 that degrades at a set of downhole conditions. The downhole conditions may be the conditions that are expected to exist in the subterranean formation 104 during a treatment placing the particle 300, conditions expected to exist after a treatment is completed, or conditions that are expected to exist at some future operating condition of wellbore 102.

[0033] For example, the shut-in temperature of the subterranean formation may be above 150° C., and the coating 302 may be a substance that degrades at temperatures above 150° C. In another example, the coating 302 may be a substance that degrades in the presence of hydrocarbons, and the coating 302 degrades over time as the wellbore 102 begins to produce hydrocarbons from the subterranean formation 104. In another example, the coating 302 may be a substance that degrades in the presence of a specific chemical, and the chemical is injected at a later time, or alternatively is released from other particles included with the treatment fluid 106 such that the coating 302 degrades at a later planned or determined time. In another example, the coating 302 may be a substance that degrades above a specific temperature, and a fluid at an elevated temperature is injected at a later time to degrade the coating 302.

[0034] FIG. 4 is an illustration of a fluid breaker profile 400. The fluid breaker profile 400 is presented as a plot of fluid viscosity 402 versus time 404. FIG. 4 represents qualitative example data illustrating an example of the effect of scale inhibitors 202 on treatment fluid 106 rheology. In certain embodiments, the scale inhibitor 202 affects the designed breaker treatment for the treatment fluid 106, resulting in a scale inhibitor breaker profile 406 that has higher viscosities than a nominal breaker profile 408. In the example, a final fluid viscosity has an offset value 410, indicating that the final achieved fluid viscosity may never reach the designed nominal viscosity. Utilizing routine rheology tests and measurement, a breaking procedure can be designed that achieves the desired breaking profile for a given embodiment. For example, an operator can add breaker aids, reduce viscosifier loadings, or increase the amount of breaker to mitigate the difference between the scale inhibitor breaker profile 406 and the nominal breaker profile 408. In certain embodiments, the scale inhibitor 202 may enhance breaker activity, resulting in a scale inhibitor breaker profile 406 having a lower viscosity than the nominal breaker profile 408, which can also be mitigated by an operator.

[0035] FIG. 5 is an illustration 500 of a scale inhibitor concentration 502 versus production fluid flowback 504 as

measured by pore volumes. The illustration 500 is example data for a system 100 including scale inhibitor 202 in an amount at 5% by weight of the proppant. The illustration 500 shows scale inhibitor concentration 508 degrading as fluid flows from the subterranean formation 104. The data shown in FIG. 5 is example data only, but systems have been demonstrated that maintain design concentrations 506 of scale inhibitor 202 for more than 500 pore volumes of flowback. In certain embodiments, the scale inhibitor 202 includes an initial amount and a dissolution rate characteristic such that the scale inhibitor concentration 508 in the produced formation fluid is greater than about 5 ppm for at least 500 fracture pore volumes of the produced fluid. In certain embodiments, the inhibitor 202 includes an initial amount and a dissolution rate characteristic such that the scale inhibitor concentration 508 in the produced formation fluid is greater than about 10 ppm for at least 450 fracture pore volumes of the produced fluid.

[0036] The schematic flow diagram and related description which follows provides an illustrative embodiment of performing operations for combined fracturing treatment and scale inhibition. Operations illustrated are understood to be exemplary only, and operations may be combined or divided, and added or removed, as well as re-ordered in whole or part, unless stated explicitly to the contrary herein.

[0037] FIG. 6 is a schematic flow diagram of a procedure 600 for scale inhibition. The procedure 600 includes an operation 602 to select a degradable material for coating particles according to a set of downhole conditions. The procedure 600 further includes an operation 604 to coat an amount of particles with the degradable material, where the amount of particles include a defined volume with a scale inhibitor in the defined volume. The procedure 600 further includes an operation 606 to prepare a treatment fluid including a carrier fluid and an amount of particles, an operation 608 to fracture a subterranean formation, and an operation 610 to place the treatment fluid in the fracture. The procedure 600 further includes an operation 612 to allow the fracture to close on the particles. The procedure 600 further includes an operation 614 to degrade the degradable material, and an operation 616 to flow production fluid from the formation fluid. The procedure 600 further includes an operation 618 to adsorb at least a portion of the degradable material on the subterranean formation matrix, and an operation 620 to generate a gel precipitate in the subterranean formation.

[0038] As is evident from the figures and text presented above, a variety of embodiments according to the present invention are contemplated.

[0039] In one exemplary embodiment, a treatment fluid for a subterranean formation is disclosed. The treatment fluid includes a carrier fluid and a first amount of particles including a granular scale inhibitor. In certain embodiments, the granular scale inhibitor includes a compound that inhibits the formation of at least one of carbonate and phosphate scales. In certain further embodiments, the carrier fluid is a hydratable gel-based fluid, a cross-linked hydratable gel-based fluid, an oil-based fluid, a visco-elastic surfactant (VES) fluid, and/or an acid-based fluid. In certain embodiments, the carrier fluid comprises a fluid with high salt tolerance.

[0040] In certain embodiments, the treatment fluid includes a second amount of particles including a proppant, and the first amount of particles are present in an amount comprising between about 1% and 5% by weight of a total amount of particles. In certain embodiments, the treatment fluid further includes an activator present in an amount between about

0.1% and 50% by weight of the scale inhibitor. The activator may be a divalent ion, an ionic salt, and/or calcium chloride.

[0041] In certain embodiments, the granular scale inhibitor includes a chemical structured to at least partially adsorb to a formation matrix. In certain embodiments, the granular scale inhibitor includes compound classes of sulfonates, phosphate esters, phosphonates, phosphonate polymers, polyacrylates and polymethacrylates, polycarboxylates, and phosphorous containing polycarboxylates, and/or phosphonic acid derivatives. In certain embodiments, the granular scale inhibitor includes compound classes of phosphino-polyacrylates and/or phosphonic acid ethylene diamine derivatives. In certain embodiments, the granular scale inhibitor includes compound classes of phosphonic acid[1,2-ethanediy]bis[nitrilobis(methylene)]tetrakis, calcium salts thereof, and/or sodium salts thereof.

[0042] In certain embodiments, the granular scale inhibitor further includes a coating structured to degrade at a set of downhole conditions. In certain further embodiments, the coating includes an encapsulation material, a surface coating, and/or a thin material film. In certain further embodiments, the coating includes polycaprolate, calcium stearate, a material structured to degrade in contact with a hydrocarbon, a material structured to degrade at a downhole temperature, and/or a material structured to degrade in a formation brine.

[0043] In an exemplary embodiment, a treatment fluid includes a carrier fluid and a first amount of particles including a proppant. The proppant includes a porosity at least partially filled with a scale inhibitor. In certain embodiments, the proppant includes a porous ceramic proppant. In certain embodiments, the porosity is at least partially filled with a scale inhibitor that includes a scale inhibitor adsorbed on pore surfaces in the proppant and/or a scale inhibitor filling at least a portion of bulk porosity in the proppant. In certain embodiments, the carrier fluid includes a hydratable gel-based fluid, a cross-linked hydratable gel-based fluid, an oil-based fluid, a visco-elastic surfactant (VES) fluid, and/or an acid-based fluid.

[0044] In certain embodiments, the scale inhibitor includes between about 1% and 5% of a total proppant weight. In certain embodiments, the treatment fluid further includes an activator present in an amount between about 0.1% and 50% by weight of the scale inhibitor. In certain further embodiments, the activator includes a divalent ion, an ionic salt, and/or calcium chloride. In certain embodiments, the scale inhibitor includes a chemical structured to at least partially adsorb to a formation matrix.

[0045] In certain embodiments, the scale inhibitor further includes a coating that degrades at a set of downhole conditions. In certain embodiments, the coating includes an encapsulation material, a surface coating, and/or a thin material film. In certain embodiments, the coating includes polycaprolate, calcium stearate, a material structured to degrade in contact with a hydrocarbon, a material structured to degrade at a downhole temperature, and/or a material structured to degrade in a formation brine. In certain embodiments, the carrier fluid includes a fluid with high salt tolerance.

[0046] In an exemplary embodiment, a method includes preparing a treatment fluid including a carrier fluid, an amount of particles each particle defining a volume, where at least a portion of the defined volume of each particle comprises a scale inhibitor. In certain embodiments, the method further includes fracturing a subterranean formation, placing

the treatment fluid in the fracture, and allowing the fracture to close on the amount of particles.

[0047] In certain embodiments, the scale inhibitor includes an initial amount and a dissolution rate characteristic, and the method further includes producing a formation fluid from the subterranean formation, wherein the initial amount and dissolution rate characteristic have values such that a concentration of the scale inhibitor in the produced formation fluid is greater than about 5 ppm for at least 500 fracture pore volumes of the produced formation fluid. In certain embodiments, the initial amount and dissolution rate characteristic have values such that a concentration of the scale inhibitor in the produced formation fluid is greater than about 10 ppm for at least 450 fracture pore volumes of the produced formation fluid.

[0048] In certain embodiments, the scale inhibitor includes a compound that inhibits the formation of at least one of carbonate and phosphate scales. In certain further embodiments, the amount of particles includes at least one of: a proppant impregnated with the scale inhibitor, a proppant having bulk porosity at least partially filled with the scale inhibitor, and a granular particle comprising the scale inhibitor. In certain further embodiments, the method further includes flowing production fluid from the subterranean formation into a wellbore intersecting the subterranean formation, and adsorbing at least a portion of the scale inhibitor on a matrix of the subterranean formation.

[0049] In certain embodiments, the method includes coating the amount of particles with a degradable material, and degrading the degradable material after the placing the treatment fluid. In certain embodiments, degrading the degradable material includes selecting a degradable material that degrades at a set of downhole conditions present in the subterranean formation. In certain embodiments, degrading the degradable material includes injecting a composition that reacts with the degradable material. In certain embodiments, degrading the degradable material includes injecting a fluid at an elevated temperature. In certain embodiments, the coating includes an encapsulation material, a surface coating, and/or a thin material film. In certain embodiments, the treatment fluid includes an activator present in an amount between about 0.1% and 50% by weight of the scale inhibitor. In certain embodiments, the method further includes generating a gel precipitate in the subterranean formation, where the gel precipitate includes at least a fraction of the scale inhibitor reacted with the activator.

[0050] In one exemplary embodiment, a system includes a wellbore intersecting a subterranean formation and an amount of treatment fluid, the treatment fluid including a carrier fluid, an amount of particles each particle defining a volume, where at least a portion of the defined volume of each particle comprises a scale inhibitor. The system further includes a pump that fractures the subterranean formation and places the treatment fluid in the fracture. In certain embodiments, the amount of particles includes an amount of a porous ceramic proppant impregnated with the scale inhibitor. In certain further embodiments, the carrier fluid includes a hydratable gel-based fluid, a cross-linked hydratable gel-based fluid, an oil-based fluid, a visco-elastic surfactant (VES) fluid, and/or an acid-based fluid.

[0051] While the invention has been illustrated and described in detail in the drawings and foregoing description, the same is to be considered as illustrative and not restrictive in character, it being understood that only the preferred

embodiments have been shown and described and that all changes and modifications that come within the spirit of the inventions are desired to be protected. It should be understood that while the use of words such as preferable, preferably, preferred, more preferred or exemplary utilized in the description above indicate that the feature so described may be more desirable or characteristic, nonetheless may not be necessary and embodiments lacking the same may be contemplated as within the scope of the invention, the scope being defined by the claims that follow. In reading the claims, it is intended that when words such as "a," "an," "at least one," or "at least one portion" are used there is no intention to limit the claim to only one item unless specifically stated to the contrary in the claim. When the language "at least a portion" and/or "a portion" is used the item can include a portion and/or the entire item unless specifically stated to the contrary.

What is claimed is:

1. A treatment fluid for a subterranean formation, the treatment fluid comprising:

a carrier fluid;

a first amount of particles comprising a granular scale inhibitor; and

wherein the granular scale inhibitor comprises a compound that inhibits the formation of at least one of carbonate and phosphate scales.

2. The treatment fluid of claim 1, wherein the granular scale inhibitor comprises a particle size greater than about 25 microns.

3. The treatment fluid of claim 1, wherein the carrier fluid comprises at least one fluid selected from the fluids consisting of: a hydratable gel-based fluid, a cross-linked hydratable gel-based fluid, an oil-based fluid, a visco-elastic surfactant (VES) fluid, and an acid-based fluid.

4. The treatment fluid of claim 1, further comprising a second amount of particles comprising a proppant, wherein the first amount of particles are present in an amount comprising between about 1% and 5% by weight of a total amount of particles.

5. The treatment fluid of claim 1, further comprising an activator present in an amount between about 0.1% and 50% by weight of the scale inhibitor.

6. The treatment fluid of claim 5, wherein the activator comprises at least one activator selected from the list consisting of a divalent ion, an ionic salt, and calcium chloride.

7. The treatment fluid of claim 1, wherein the carrier fluid comprises a fluid with high salt tolerance.

8. The treatment fluid of claim 1, wherein the granular scale inhibitor comprises a chemical structured to at least partially adsorb to a formation matrix.

9. The treatment fluid of claim 1, wherein the granular scale inhibitor comprises at least one compound selected from the classes consisting of sulfonates, phosphate esters, phosphonates, phosphonate polymers, polyacrylates and polymethacrylates, polycarboxylates, and phosphorous containing polycarboxylates, and phosphonic acid derivatives.

10. The treatment fluid of claim 1, wherein the granular scale inhibitor comprises at least one compound selected from the classes consisting of phosphino-polyacrylates and phosphonic acid ethylene diamine derivatives.

11. The treatment fluid of claim 1, wherein the granular scale inhibitor comprises at least one compound selected from the classes consisting of phosphonic acid[1,2-

ethanedylbis[nitrilobis(methylene)]]tetrakis, calcium salts thereof, and sodium salts thereof.

12. The treatment fluid of claim 1, wherein the granular scale inhibitor further includes a coating structured to degrade at a set of downhole conditions.

13. The treatment fluid of claim 12, wherein the coating comprises a coating selected from the group consisting of an encapsulation material, a surface coating, and a thin material film.

14. The treatment fluid of claim 12, wherein the coating comprises at least one coating selected from the group consisting of polycaprolate, calcium stearate, a material structured to degrade in contact with a hydrocarbon, a material structured to degrade at a downhole temperature, and a material structured to degrade in a formation brine.

15. A treatment fluid for a subterranean formation, the treatment fluid comprising:

a carrier fluid;

a first amount of particles comprising a proppant; and

wherein the proppant includes a porosity at least partially filled with a scale inhibitor.

16. The treatment fluid of claim 15, wherein the proppant has a size at least equal to a 100 mesh.

17. The treatment fluid of claim 15, wherein the proppant comprises a porous ceramic proppant.

18. The treatment fluid of claim 15, wherein the porosity at least partially filled with a scale inhibitor comprises at least one of the scale inhibitor adsorbed on pore surfaces in the proppant and the scale inhibitor filling at least a portion of bulk porosity in the proppant.

19. The treatment fluid of claim 15, wherein the carrier fluid comprises at least one fluid selected from the fluids consisting of: a hydratable gel-based fluid, a cross-linked hydratable gel-based fluid, an oil-based fluid, a visco-elastic surfactant (VES) fluid, and an acid-based fluid.

20. The treatment fluid of claim 15, wherein the scale inhibitor comprises between about 1% and 5% of a total proppant weight.

21. The treatment fluid of claim 15, further comprising an activator present in an amount between about 0.1% and 50% by weight of the scale inhibitor.

22. The treatment fluid of claim 21, wherein the activator comprises at least one activator selected from the list consisting of a divalent ion, an ionic salt, and calcium chloride.

23. The treatment fluid of claim 15, wherein the scale inhibitor comprises a chemical structured to at least partially adsorb to a formation matrix.

24. The treatment fluid of claim 15, wherein the scale inhibitor comprises at least one compound selected from the classes consisting of sulfonates, phosphate esters, phosphonates, phosphonate polymers, polyacrylates and polymethacrylates, polycarboxylates, and phosphorous containing polycarboxylates, and phosphonic acid derivatives.

25. The treatment fluid of claim 15, wherein the scale inhibitor comprises at least one compound selected from the classes consisting of phosphino-polyacrylates and phosphonic acid ethylene diamine derivatives.

26. The treatment fluid of claim 15, wherein the scale inhibitor comprises at least one compound selected from the

classes consisting of phosphonic acid[1,2-ethanedylbis[nitrilobis(methylene)]]tetrakis, and calcium and sodium salts thereof.

27. The treatment fluid of claim 15, wherein the scale inhibitor further includes a coating structured to degrade at a set of downhole conditions.

28. The treatment fluid of claim 27, wherein the coating comprises a coating selected from the group consisting of an encapsulation material, a surface coating, and a thin material film.

29. The treatment fluid of claim 27, wherein the coating comprises at least one coating selected from the group consisting of polycaprolate, calcium stearate, a material structured to degrade in contact with a hydrocarbon, a material structured to degrade at a downhole temperature, and a material structured to degrade in a formation brine.

30. The treatment fluid of claim 15, wherein the carrier fluid comprises a fluid with high salt tolerance.

31. A method, comprising:

preparing a treatment fluid comprising a carrier fluid, an amount of particles each particle defining a volume, wherein at least a portion of the defined volume of each particle comprises a scale inhibitor, and wherein the amount of particles comprise a particle size greater than about 25 microns;

fracturing a subterranean formation;

placing the treatment fluid in the fracture; and

allowing the fracture to close on the amount of particles.

32. The method of claim 31, wherein the scale inhibitor comprises an initial amount and a dissolution rate characteristic, the method further comprising producing a formation fluid from the subterranean formation, wherein the initial amount and dissolution rate characteristic have values such that a concentration of the scale inhibitor in the produced formation fluid is greater than about 5 ppm for at least 500 fracture pore volumes of the produced formation fluid.

33. The method of claim 31, wherein the scale inhibitor comprises an initial amount and a dissolution rate characteristic, the method further comprising producing a formation fluid from the subterranean formation, wherein the initial amount and dissolution rate characteristic have values such that a concentration of the scale inhibitor in the produced formation fluid is greater than about 10 ppm for at least 450 fracture pore volumes of the produced formation fluid.

34. The method of claim 31, wherein the scale inhibitor comprises a compound that inhibits the formation of at least one of carbonate and phosphate scales.

35. The method of claim 31, wherein the amount of particles comprises at least one particle selected from the list consisting of: a proppant impregnated with the scale inhibitor, a proppant having bulk porosity at least partially filled with the scale inhibitor, and a granular particle comprising the scale inhibitor.

36. The method of claim 31, further comprising flowing production fluid from the subterranean formation into a well-bore intersecting the subterranean formation, and adsorbing at least a portion of the scale inhibitor on a matrix of the subterranean formation.

37. The method of claim 31, further comprising coating the amount of particles with a degradable material, and degrading the degradable material after the placing the treatment fluid.

38. The method of claim **37**, wherein the degrading the degradable material comprises selecting a degradable material structured to degrade at a set of downhole conditions present in the subterranean formation.

39. The method of claim **37**, wherein the degrading the degradable material comprises injecting a composition that reacts with the degradable material.

40. The method of claim **37**, wherein the degrading the degradable material comprises injecting a fluid at an elevated temperature.

41. The method of claim **37**, wherein the coating comprises a coating selected from the group consisting of an encapsulation material, a surface coating, and a thin material film.

42. The method of claim **31**, wherein the treatment fluid further includes an activator present in an amount between about 0.1% and 50% by weight of the scale inhibitor.

43. The method of claim **42**, further comprising generating a gel precipitate in the subterranean formation, wherein the gel precipitate comprises at least a fraction of the scale inhibitor reacted with the activator.

44. A system, comprising:

a wellbore intersecting a subterranean formation;
an amount of treatment fluid, comprising: a carrier fluid, an amount of particles each particle defining a volume, wherein at least a portion of the defined volume of each particle comprises a scale inhibitor; and
a pump structured to fracture the subterranean formation, and to place the treatment fluid in the fracture.

45. The system of claim **44**, wherein the amount of particles comprises an amount of a porous ceramic proppant impregnated with the scale inhibitor.

46. The system of claim **45**, wherein the amount of particles comprise a particle size at least equal to a 100 mesh.

47. The system of claim **44**, wherein the carrier fluid comprises at least one fluid selected from the fluids consisting of: a hydratable gel-based fluid, a cross-linked hydratable gel-based fluid, an oil-based fluid, a visco-elastic surfactant (VES) fluid, and an acid-based fluid.

48. The system of claim **44**, wherein the amount of particles comprise a particle size greater than about 25 microns.

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