



(43) International Publication Date
1 October 2015 (01.10.2015)

- (51) International Patent Classification:
E21B 43/26 (2006.01) *C09K 8/80* (2006.01)
C09K 8/62 (2006.01)
- (21) International Application Number:
PCT/US2015/020316
- (22) International Filing Date:
13 March 2015 (13.03.2015)
- (25) Filing Language: English
- (26) Publication Language: English
- (30) Priority Data:
14/228,295 28 March 2014 (28.03.2014) US
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(54) Title: WELL TREATMENT

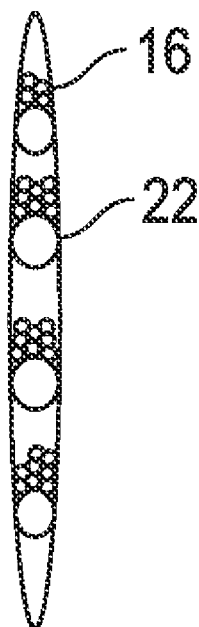


FIG. 1C

(57) Abstract: A method and system for increasing fracture conductivity. A slurry, of a solid particulate freely dispersed in fluid spaces around macrostructures suspended in a carrier fluid, is injected into a fracture, the solid particulate is aggregated in the fracture to form clusters, and the pressure reduced to prop the fracture open on the clusters and form interconnected, hydraulically conductive channels between the clusters. The system comprises a subterranean formation, a treatment slurry stage disposed in a wellbore penetrating the formation, and a pump system to inject the treatment fluid stage into a fracture.



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(81) **Designated States** (*unless otherwise indicated, for every kind of national protection available*): AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BN, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IR, IS, JP, KE, KG, KN,

KP, KR, KZ, LA, LC, LK, LR, LS, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SA, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

(84) **Designated States** (*unless otherwise indicated, for every kind of regional protection available*): ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, ST, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, KM, ML, MR, NE, SN, TD, TG).

Published:

— with international search report (Art. 21(3))

WELL TREATMENT

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application claims priority to U.S. Patent Application having Serial No. 14/228,295, filed on March 28, 2014, entitled "Well Treatment" the entirety of which is incorporated by reference herein.

BACKGROUND

[0002] The statements in this section merely provide background information related to the present disclosure and may not constitute prior art.

[0003] Fracturing is used to create conductive pathways in a subterranean formation and increase fluid flow between the formation and the wellbore. A fracturing fluid is injected into the wellbore passing through the subterranean formation. A propping agent (proppant) is injected into the fracture to prevent fracture closure and, thereby, to provide improved extraction of extractive fluids, such as oil, gas or water.

[0004] The proppant maintains the distance between the fracture walls in order to create conductive channels in the formation. The pulsed injection of alternating proppant-free and fiber-stabilized, proppant-laden slugs into the fracture has been used to obtain a heterogeneous distribution of proppant particles into a channels and pillars configuration, which can improve the conductivity in the fracture. Accordingly, there is a demand for further improvements in this area of technology.

SUMMARY

[0005] In some embodiments according to the disclosure herein, an in situ method and system are provided for increasing fracture conductivity. In embodiments, a method for treating a subterranean formation penetrated by a wellbore may comprise: injecting a treatment stage fluid, comprising a slurry of a solid particulate freely dispersed in fluid spaces around macrostructures

suspended in a carrier fluid, into a fracture in the formation; aggregating the solid particulate in the fracture to form clusters at respective interfaces with adjacent macrostructures; and reducing pressure in the fracture to prop the fracture open on the clusters and form interconnected, hydraulically conductive channels between the clusters. In some embodiments, the macrostructures may be or comprise long fibers, gel bodies or the like. In some embodiments, the macrostructures may comprise gel bodies comprising an internal phase(s) of a fiber, solid particulate, or the like.

[0006] In some embodiments, a system to produce reservoir fluids comprises the wellbore and fracture resulting from any of the fracturing methods disclosed herein.

[0007] In embodiments, a system comprises: a subterranean formation penetrated by a wellbore; a treatment slurry stage disposed in the wellbore, the treatment slurry stage comprising a slurry of a solid particulate freely dispersed in fluid spaces around macrostructures suspended in a carrier fluid; and a pump system to inject the treatment fluid stage from the wellbore to the formation at a pressure above fracturing pressure to inject the treatment fluid stage into a fracture in the formation.

BRIEF DESCRIPTION OF THE DRAWINGS

[0008] These and other features and advantages will be better understood by reference to the following detailed description when considered in conjunction with the accompanying drawings.

[0009] Fig. 1A is a schematic diagram of a fracture filled with proppant and elongated macrostructures according to some embodiments of the current application.

[0010] Fig. 1B is a schematic diagram of the proppant settlement into clusters in the fracture of Fig. 1A according to some embodiments of the current application.

[0011] Fig. 1C is a schematic diagram showing a cross sectional elevation of the fracture of Fig. 1B as seen along the view lines 1C-1C according to some embodiments of the current application.

[0012] Fig. 2A is a schematic diagram of a fracture uniformly filled with proppant and gel macrostructures according to some embodiments of the current application.

[0013] Fig. 2B is a schematic diagram of the proppant settlement in the fracture of Fig. 2A according to some embodiments of the current application.

[0014] Fig. 2C is a schematic diagram of the conductive paths in the fracture of Fig. 2B following fracture closure according to some embodiments of the current application.

[0015] Fig. 3A is a schematic diagram of a fracture uniformly filled with proppant and gel macrostructures according to some embodiments of the current application.

[0016] Fig. 3B is a schematic diagram of the elongated macrostructures following closure in the fracture of Fig. 3A according to some embodiments of the current application.

[0017] Fig. 3C is a schematic diagram of the conductive paths in the fracture of Fig. 3B following gel macrostructure breaking according to some embodiments of the current application.

[0018] Fig. 4 is a schematic diagram of a spherical macrostructure supporting settled proppant according to some embodiments of the current application.

[0019] Fig. 5 is a schematic diagram of a transversely cylindrical macrostructure supporting settled proppant according to some embodiments of the current application.

[0020] Fig. 6 is a schematic diagram of a longitudinally cylindrical macrostructure supporting settled proppant according to some embodiments of the current application.

[0021] Fig. 7 is a schematic diagram of the cluster volume corresponding to proppant supported on a cylindrical macrostructure in a fracture according to some embodiments of the current application.

5 **[0022]** Fig. 8A is a photograph of a slot filled with proppant and gel macrostructures as described in Example 1 according to some embodiments of the current application.

[0023] Fig. 8B is a photograph of the slot of Fig. 8A following some proppant settlement as described in Example 1 according to some embodiments of the current application.

10 **[0024]** Fig. 9A is a photograph of a slot filled with proppant and gel macrostructures as described in Example 3 according to some embodiments of the current application.

[0025] Fig. 9B is a photograph of the slot of Fig. 9A following breaking of the gel macrostructures as described in Example 3 according to some embodiments of
15 the current application.

[0026] Fig. 10A is a photograph of a slot filled with gel macrostructures as described in Example 4 according to some embodiments of the current application.

20 **[0027]** Fig. 10B is a photograph of the slot of Fig. 10A following breaking of the gel macrostructures as described in Example 4 according to some embodiments of the current application.

[0028] Fig. 11A is a photograph of a slot filled with proppant and fiber macrostructures as described in Example 5 according to some embodiments of the current application.

25 **[0029]** Fig. 11B is a photograph of the slot of Fig. 11A following some proppant settlement as described in Example 5 according to some embodiments of the current application.

DETAILED DESCRIPTION OF SOME ILLUSTRATIVE EMBODIMENTS

[0030] For the purposes of promoting an understanding of the principles of the disclosure, reference will now be made to some illustrative embodiments of the current application. Like reference numerals used herein refer to like parts in the various drawings. Reference numerals without suffixed letters refer to the part(s)
5 in general; reference numerals with suffixed letters refer to a specific one of the parts.

[0031] As used herein, “embodiments” refers to non-limiting examples of the application disclosed herein, whether claimed or not, which may be employed or
10 present alone or in any combination or permutation with one or more other embodiments. Each embodiment disclosed herein should be regarded both as an added feature to be used with one or more other embodiments, as well as an alternative to be used separately or in lieu of one or more other embodiments. It should be understood that no limitation of the scope of the claimed subject matter
15 is thereby intended, any alterations and further modifications in the illustrated embodiments, and any further applications of the principles of the application as illustrated therein as would normally occur to one skilled in the art to which the disclosure relates are contemplated herein.

[0032] Moreover, the schematic illustrations and descriptions provided herein are
20 understood to be examples only, and components 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. Certain operations illustrated may be implemented by a computer executing a computer program product on a computer readable medium, where the computer program product comprises
25 instructions causing the computer to execute one or more of the operations, or to issue commands to other devices to execute one or more of the operations.

[0033] It should be understood that, although a substantial portion of the following detailed description may be provided in the context of oilfield hydraulic fracturing operations, other oilfield operations such as cementing, gravel packing, etc., or

even non-oilfield well treatment operations, can utilize and benefit as well from the instant disclosure.

[0034] According to some embodiments herein, a method for treating a subterranean formation penetrated by a wellbore may comprise injecting a treatment stage fluid, comprising a slurry of a solid particulate freely dispersed in fluid spaces around macrostructures suspended in a carrier fluid, into a fracture in the formation; aggregating the solid particulate in the fracture to form clusters at respective interfaces with adjacent macrostructures; and reducing pressure in the fracture to prop the fracture open on the clusters and form interconnected, hydraulically conductive channels between the clusters.

[0035] According to some embodiments of the method, the solid particulate comprises disaggregated proppant and the treatment fluid stage is a proppant-laden hydraulic fracturing fluid. According to some embodiments of the method, the carrier fluid comprises fiber present in the fluid spaces around the macrostructures to stabilize the treatment stage fluid for the injection into the fracture.

[0036] According to some embodiments, the method may further comprise viscosifying the carrier fluid for injection into the formation, and breaking the carrier fluid (thus reducing its viscosity) in the fracture to trigger the aggregation of the solid particulates.

[0037] According to some embodiments, the method may further comprise successively alternating concentration modes of the macrostructures in the treatment stage fluid between a relatively macrostructure-rich mode and a macrostructure-lean mode during the treatment stage fluid injection.

[0038] According to some embodiments of the method, the macrostructures comprise viscous gel. According to some embodiments of the method, the macrostructures comprise viscous gel comprising crosslinked polymer. According to some embodiments of the method, the macrostructures comprise viscous gel comprising crosslinked polymer selected from polysaccharides,

polyacrylates, alginates, polyacrylamides, and combinations thereof. According to some embodiments of the method, the macrostructures comprise viscous gel reinforced with proppant, subproppant, fiber or a combination thereof.

5 **[0039]** According to some embodiments, the method may further comprise degrading the macrostructures after the aggregation of the solid particulate in the fracture.

10 **[0040]** According to some embodiments, the method may further comprise elongating the macrostructures in the fracture. According to some embodiments of the method, the macrostructures comprise a gel relatively more viscous than the carrier fluid, and the method may further comprise elongating the macrostructures in the fracture by restraining flow of the macrostructures in the fracture relative to the carrier fluid, by compression of the macrostructures during fracture closure, or by a combination thereof.

15 **[0041]** According to some embodiments of the method, the macrostructures comprise viscous gel and the method may further comprise compression and elongation of the macrostructures during fracture closure to form gel-filled channels comprising a plurality of the elongated macrostructures in contact with each other.

20 **[0042]** According to some embodiments of the method, the macrostructures in the injection comprise a volume in the treatment fluid from 5 to 30 volume percent [e.g. 15 vol%] and the solid particulate comprises a volume in the treatment fluid from 95 to 70 volume percent [e.g., 85 vol%], based on the total volume of the macrostructures and solid particulate in the treatment fluid.

25 **[0043]** According to some embodiments of the method, the macrostructures have a dimension at least 10 times larger than the solid particulate. According to some embodiments of the method, the macrostructures comprise long fibers having a length of at least about 0.75 cm. According to some embodiments of the method, the macrostructures comprise long fibers having a length of from about 1 cm to about 7.5 cm, or from 1 cm to 5 cm.

[0044] According to some embodiments of the method, the injection into the fracture is at a continuous rate of the treatment fluid stage with a continuous concentration of the solid particulate; and further comprising, while maintaining the continuous rate and solid particulate concentration during injection of the treatment fluid stage, successively alternating concentration modes of the macrostructures in the treatment fluid stage between a plurality of relatively macrostructure-rich modes and a plurality of macrostructure-lean modes. According to some embodiments, the injection of the treatment fluid stage forms a homogenous region within the fracture of continuously uniform distribution of the first solid particulate, and wherein the alternation of the concentration modes of the macrostructures forms heterogeneous areas within the fracture comprising macrostructure-rich areas and macrostructure-lean areas.

[0045] According to some embodiments, the method may further comprise forming bridges with the macrostructures in the fracture to retain the clusters.

[0046] According to some embodiments of the method, the macrostructures are selected from a fiber, a floc, a flake, a ribbon, a platelet, a rod, or a combination thereof.

[0047] According to some embodiments of the method, the macrostructures are selected from the group consisting of polylactic acid (PLA), polyglycolic acid (PGA), polyethylene terephthalate (PET), polyester, polyamide, polycaprolactam and polylactone, poly(butylene succinate), polydioxanonepolylactic acid, polyester, polycaprolactam, polyamide, polyglycolic acid, polyterephthalate, or a combination thereof.

[0048] According to some embodiments of the method, the macrostructures are long fibers selected from the group consisting of glass, ceramics, carbon (including carbon-based compounds), elements in metallic form, metal alloys, wool, basalt, acrylic, polyethylene, polypropylene, novoloid resin, polyphenylene sulfide, polyvinyl chloride, polyvinylidene chloride, polyurethane, polyvinyl alcohol, polybenzimidazole, polyhydroquinone-diimidazopyridine, poly(p-

phenylene-2,6-benzobisoxazole), rayon, cotton, or other natural fibers, cellulose, wool, basalt, glass, rubber, acrylic, mica, and combinations thereof. According to some embodiments of the method, the macrostructures comprise sticky fiber.

5 **[0049]** According to some embodiments of the method, the macrostructures are degradable and the method may further comprise degrading the macrostructures after closure of the fracture.

10 **[0050]** According to some embodiments, a system may comprise a subterranean formation penetrated by a wellbore; a treatment slurry stage disposed in the wellbore, the treatment slurry stage comprising a slurry of a solid particulate freely dispersed in fluid spaces around macrostructures suspended in a carrier fluid; and a pump system to inject the treatment fluid stage from the wellbore to the formation at a pressure above fracturing pressure to inject the treatment fluid stage into a fracture in the formation.

15 **[0051]** According to some embodiments of the system, the solid particulate comprises disaggregated proppant and the treatment fluid stage is a proppant-laden hydraulic fracturing fluid.

[0052] According to some embodiments of the system, the carrier fluid comprises fiber present in the fluid spaces around the macrostructures to stabilize the treatment stage fluid for the injection into the fracture.

20 **[0053]** According to some embodiments of the system, the treatment slurry stage further comprises a viscosifier in the carrier fluid and a breaker to break the carrier fluid in the fracture to enable the aggregation of the solid particulate.

25 **[0054]** According to some embodiments of the system, the treatment slurry stage further comprises successively alternating concentration modes of the macrostructures in the treatment slurry stage between a relatively macrostructure-rich mode and a macrostructure-lean mode during the treatment slurry stage injection.

[0055] According to some embodiments of the system, the macrostructures comprise viscous gel. According to some embodiments of the system, the macrostructures comprise viscous gel comprising crosslinked polymer. According to some embodiments of the system, the macrostructures comprise viscous gel comprising crosslinked polymer selected from polysaccharides, polyacrylates, alginates, polyacrylamides, and combinations thereof. According to some embodiments of the system, the macrostructures comprise viscous gel reinforced with proppant, subproppant, fiber or a combination thereof. According to some embodiments of the system, the macrostructures comprise a gel relatively more viscous than the carrier fluid.

[0056] According to some embodiments of the system, the macrostructures comprise a volume in the treatment slurry stage from 5 to 30 volume percent [e.g. 15 vol%] and the solid particulate comprises a volume in the treatment slurry stage from 95 to 70 volume percent [e.g., 85 vol%], based on the total volume of the macrostructures and solid particulate in the treatment slurry stage.

[0057] According to some embodiments of the system, the macrostructures have a dimension at least 10 times larger than the solid particulate. According to some embodiments of the system, the macrostructures comprise long fibers having a length of at least about 0.75 cm. According to some embodiments of the system, the macrostructures comprise long fibers having a length of from about 1 cm to about 7.5 cm.

[0058] With reference to Figs. 1A – 1C, in some embodiments of the disclosure, treatment fluid is injected from supply station 10 through wellbore 12 and portal 14, e.g., perforation(s) in a cased completion or fracture opening(s) in the case of an open hole completion, into fracture 16 as indicated by flow arrow 18, to more or less uniformly distribute solid particulate 20, e.g., proppant and/or subproppant particles, and macrostructures 22, e.g., gel bodies, fibers or the like. At shut in and/or activation of a trigger, the particulate 20 settles as indicated by flow arrows 24 in Fig. 1A, and forms clusters 26 at macrostructures 22 as shown in Figs. 1B-1C, which keep the fracture open and form flow channels around the

clusters 26. As used herein, a macrostructure refers to a physical body, which may be solid, semi-solid or gelatinous, having a dimension sufficient to retain a plurality of proppant particles on a surface thereof, i.e., at least 3 times larger than the proppant or the largest ones of other solid particulates. In some
5 embodiments, the macrostructures may have at least one dimension larger than 5 mm, e.g., from 5 mm to 80 mm, or from 8 mm to 50 mm, or from 25 to 50 mm, or from 10 to 30 mm, etc.

[0059] In some embodiments, the macrostructures may comprise a material, such as fibers, flocs, flakes, discs, rods, stars, balls, blobs, etc., for example,
10 which may be distributed in the fracture, homogeneously and/or heterogeneously, and having a capability to anchor to a surface of the fracture, e.g., by having a size to be compressed between opposing fracture surfaces and/or a surface(s) with an adhesive or attractant characteristic to adhere or cling to a fracture surface. As used herein, the term “flocs” includes both flocculated
15 colloids and colloids capable of forming flocs in the treatment fluid.

[0060] In some embodiments, the particulate solids may be proppant or gravel. “Proppant” refers to particulates that are used in well work-overs and treatments, such as hydraulic fracturing operations, to hold fractures open following the treatment. In some embodiments, the proppant may be of a particle size mode
20 or modes in the slurry having a weight average mean particle size greater than or equal to about 100 microns, e.g., 140 mesh particles correspond to a size of 105 microns. In further embodiments, the proppant may comprise particles or aggregates made from particles with size from 0.001 to 1 mm. All individual values from 0.001 to 1 mm are disclosed and included herein. For example, the
25 solid particulate size may be from a lower limit of 0.001, 0.01, 0.1 or 0.9 mm to an upper limit of 0.009, 0.07, 0.5 or 1 mm. Here particle size is defined is the largest dimension of the grain of said particle.

[0061] “Gravel” refers to particles used in gravel packing, and the term is synonymous with proppant as used herein. “Sub-proppant” or “subproppant”
30 refers to particles or particle size or mode (including colloidal and submicron

particles) having a smaller size than the proppant mode(s); references to “proppant” exclude subproppant particles and vice versa. In an embodiment, the sub-proppant mode or modes each have a weight average mean particle size less than or equal to about one-half of the weight average mean particle size of a smallest one of the proppant modes, e.g., a suspensive/stabilizing mode.

[0062] In some embodiments the macrostructures may be gel bodies such as balls or blobs made with a viscosifier, such as for example, a water soluble polymer such as polysaccharide like hydroxyethylcellulose (HEC) and/or guar, copolymers of polyacrylamide and their derivatives, and the like, e.g., at a concentration of 1.2 to 24 g/L (10 to 200 ppt where “ppt” is pounds per 1000 gallons of fluid), or a viscoelastic surfactant (VES). The polymer in some embodiments may be crosslinked with a crosslinker such as metal, e.g., calcium or borate. The gel bodies may further optionally comprise fibers and/or particulates dispersed in an internal phase.

[0063] In some embodiments, the treatment fluid comprises a liquid carrier fluid such as water, brine, oil or an emulsion, invert emulsion or the like, or an energized fluid or foam. In some embodiments, the liquid comprises a viscosified carrier fluid, and the method may further comprise reducing the viscosity of the carrier fluid in the fracture to induce settling of the solid particulate prior to closure of the fracture, and thereafter allowing the fracture to close.

[0064] As used herein, the terms “treatment fluid” or “wellbore treatment fluid” are inclusive of “fracturing fluid” or “treatment slurry” and should be understood broadly. These may be or include a liquid, a solid, a gas, and combinations thereof, as will be appreciated by those skilled in the art. A treatment fluid may take the form of a solution, an emulsion, an energized fluid (including foam), slurry, or any other form as will be appreciated by those skilled in the art.

[0065] As used herein, “slurry” refers to an optionally flowable mixture of particles dispersed in a fluid carrier. The terms “flowable” or “pumpable” or “mixable” are used interchangeably herein and refer to a fluid or slurry that has either a yield

stress or low-shear (5.11 s^{-1}) viscosity less than 1000 Pa and a dynamic apparent viscosity of less than 10 Pa-s (10,000 cP) at a shear rate 170 s^{-1} , where yield stress, low-shear viscosity and dynamic apparent viscosity are measured at a temperature of 25°C unless another temperature is specified explicitly or in context of use.

[0066] “Viscosity” as used herein unless otherwise indicated refers to the apparent dynamic viscosity of a fluid at a temperature of 25°C and shear rate of 170 s^{-1} .

[0067] “Treatment fluid” or “fluid” (in context) refers to the entire treatment fluid, including any proppant, subproppant particles, liquid, gas etc. “Whole fluid,” “total fluid” and “base fluid” are used herein to refer to the fluid phase plus any subproppant particles dispersed therein, but exclusive of proppant particles. “Carrier,” “fluid phase” or “liquid phase” refer to the fluid or liquid that is present, which may comprise a continuous phase and optionally one or more discontinuous gas or liquid fluid phases dispersed in the continuous phase, including any solutes, thickeners or colloidal particles only, exclusive of other solid phase particles; reference to “water” in the slurry refers only to water and excludes any gas, liquid or solid particles, solutes, thickeners, colloidal particles, etc.; reference to “aqueous phase” refers to a carrier phase comprised predominantly of water, which may be a continuous or dispersed phase. As used herein the terms “liquid” or “liquid phase” encompasses both liquids per se and supercritical fluids, including any solutes dissolved therein.

[0068] The term “dispersion” means a mixture of one substance dispersed in another substance, and may include colloidal or non-colloidal systems. As used herein, “emulsion” generally means any system with one liquid phase dispersed in another immiscible liquid phase, and may apply to oil-in-water and water-in-oil emulsions. Invert emulsions refer to any water-in-oil emulsion in which oil is the continuous or external phase and water is the dispersed or internal phase.

[0069] The terms "energized fluid" and "foam" refer to a fluid which when subjected to a low pressure environment liberates or releases gas from solution or dispersion, for example, a liquid containing dissolved gases. Foams or energized fluids are stable mixtures of gases and liquids that form a two-phase system. Foam and energized fluids are generally described by their foam quality, i.e. the ratio of gas volume to the foam volume (fluid phase of the treatment fluid), i.e., the ratio of the gas volume to the sum of the gas plus liquid volumes). If the foam quality is between 52% and 95%, the energized fluid is usually called foam. Above 95%, foam is generally changed to mist. In the present patent application, the term "energized fluid" also encompasses foams and refers to any stable mixture of gas and liquid, regardless of the foam quality. Energized fluids comprise any of:

(a) Liquids that at bottom hole conditions of pressure and temperature are close to saturation with a species of gas. For example the liquid can be aqueous and the gas nitrogen or carbon dioxide. Associated with the liquid and gas species and temperature is a pressure called the bubble point, at which the liquid is fully saturated. At pressures below the bubble point, gas emerges from solution;

(b) Foams, consisting generally of a gas phase, an aqueous phase and a solid phase. At high pressures the foam quality is typically low (i.e., the non-saturated gas volume is low), but quality (and volume) rises as the pressure falls. Additionally, the aqueous phase may have originated as a solid material and once the gas phase is dissolved into the solid phase, the viscosity of solid material is decreased such that the solid material becomes a liquid; or

(c) Liquefied gases.

[0070] As used herein unless otherwise specified, as described in further detail herein, particle size and particle size distribution (PSD) mode refer to the median volume averaged size. The median size used herein may be any value

understood in the art, including for example and without limitation a diameter of roughly spherical particulates. In an embodiment, the median size may be a characteristic dimension, which may be a dimension considered most descriptive of the particles for specifying a size distribution range.

5 **[0071]** As used herein, a “water soluble polymer” refers to a polymer which has a water solubility of at least 5 wt% (0.5 g polymer in 9.5 g water) at 25°C.

[0072] The measurement or determination of the viscosity of the liquid phase (as opposed to the treatment fluid or base fluid) may be based on a direct measurement of the solids-free liquid, or a calculation or correlation based on a
10 measurement(s) of the characteristics or properties of the liquid containing the solids, or a measurement of the solids-containing liquid using a technique where the determination of viscosity is not affected by the presence of the solids. As used herein, solids-free for the purposes of determining the viscosity of the liquid phase means in the absence of non-colloidal particles larger than 1 micron such
15 that the particles do not affect the viscosity determination, but in the presence of any submicron or colloidal particles that may be present to thicken and/or form a gel with the liquid, i.e., in the presence of ultrafine particles that can function as a thickening agent. In some embodiments, a “low viscosity liquid phase” means a viscosity less than about 300 mPa-s measured without any solids greater than 1
20 micron at 170 s^{-1} and 25°C.

[0073] In some embodiments, the treatment fluid may include a continuous fluid phase, also referred to as an external phase, and a discontinuous phase(s), also referred to as an internal phase(s), which may be a fluid (liquid or gas) in the case of an emulsion, foam or energized fluid, or which may be a solid in the case
25 of a slurry. The continuous fluid phase, also referred to herein as the carrier fluid or comprising the carrier fluid, may be any matter that is substantially continuous under a given condition. Examples of the continuous fluid phase include, but are not limited to, water, hydrocarbon, gas (e.g., nitrogen or methane), liquefied gas (e.g., propane, butane, or the like), etc., which may include solutes, e.g. the fluid
30 phase may be a brine, and/or may include a brine or other solution(s). In some

embodiments, the fluid phase(s) may optionally include a viscosifying and/or yield point agent and/or a portion of the total amount of viscosifying and/or yield point agent present. Some non-limiting examples of the fluid phase(s) include hydratable gels and mixtures of hydratable gels (e.g. gels containing
5 polysaccharides such as guar and their derivatives, xanthan and diutan and their derivatives, hydratable cellulose derivatives such as hydroxyethylcellulose, carboxymethylcellulose and others, polyvinyl alcohol and its derivatives, other hydratable polymers, colloids, etc.), a cross-linked hydratable gel, a viscosified acid (e.g. gel-based), an emulsified acid (e.g. oil outer phase), an energized fluid
10 (e.g., an N₂ or CO₂ based foam), a viscoelastic surfactant (VES) viscosified fluid, and an oil-based fluid including a gelled, foamed, or otherwise viscosified oil.

[0074] The discontinuous phase if present in the treatment fluid may be any particles (including fluid droplets) that are suspended or otherwise dispersed in the continuous phase in a disjointed manner. In this respect, the discontinuous
15 phase can also be referred to, collectively, as “particle” or “particulate” which may be used interchangeably. As used herein, the term “particle” should be construed broadly. For example, in some embodiments, the particle(s) of the current application are solid such as proppant, sands, ceramics, crystals, salts, etc.; however, in some other embodiments, the particle(s) can be liquid, gas, foam,
20 emulsified droplets, etc. Moreover, in some embodiments, the particle(s) of the current application are substantially stable and do not change shape or form over an extended period of time, temperature, or pressure; in some other embodiments, the particle(s) of the current application are degradable, expandable, swellable, dissolvable, deformable, meltable, sublimeable, or
25 otherwise capable of being changed in shape, state, or structure.

[0075] In an embodiment, the particle(s) is substantially round and spherical. In an embodiment, the particle(s) is not substantially spherical and/or round, e.g., it can have varying degrees of sphericity and roundness, according to the API RP-60 sphericity and roundness index. For example, the microstructure or other
30 particle(s) may have an aspect ratio of more than 2, 3, 4, 5 or 6. Examples of

such non-spherical particles include, but are not limited to, fibers, flocs, flakes, discs, rods, stars, etc. All such variations should be considered within the scope of the current application.

[0076] Introducing high-aspect ratio particles into the treatment fluid, e.g., particles having an aspect ratio of at least 6, represents additional or alternative embodiments for stabilizing the treatment fluid and inhibiting settling during proppant placement, which can be removed, for example by dissolution or degradation into soluble degradation products. Examples of such non-spherical particles include, but are not limited to, fibers, flocs, flakes, discs, rods, stars, etc., as described in, for example, US7275596, US20080196896, which are hereby incorporated herein by reference. In an embodiment, introducing ciliated or coated proppant into the treatment fluid may also stabilize or help stabilize the treatment fluid or regions thereof. Proppant or other particles coated with a hydrophilic polymer can make the particles behave like larger particles and/or more tacky particles in an aqueous medium. The hydrophilic coating on a molecular scale may resemble ciliates, i.e., proppant particles to which hairlike projections have been attached to or formed on the surfaces thereof. Herein, hydrophilically coated proppant particles are referred to as “ciliated or coated proppant.” Hydrophilically coated proppants and methods of producing them are described, for example, in WO 2011-050046, US 5,905,468, US 8,227,026 and US 8,234,072, which are hereby incorporated herein by reference.

[0077] In an embodiment, the particles may be multimodal. As used herein multimodal refers to a plurality of particle sizes or modes which each has a distinct size or particle size distribution, e.g., proppant and fines. As used herein, the terms distinct particle sizes, distinct particle size distribution, or multi-modes or multimodal, mean that each of the plurality of particles has a unique volume-averaged particle size distribution (PSD) mode. That is, statistically, the particle size distributions of different particles appear as distinct peaks (or “modes”) in a continuous probability distribution function. For example, a mixture of two particles having normal distribution of particle sizes with similar variability is considered a bimodal particle mixture if their respective means differ by more than the sum of their respective standard deviations, and/or if their respective

means differ by a statistically significant amount. In an embodiment, the particles contain a bimodal mixture of two particles; in an embodiment, the particles contain a trimodal mixture of three particles; in an embodiment, the particles contain a tetramodal mixture of four particles; in an embodiment, the particles contain a pentamodal mixture of five particles, and so on. Representative references disclosing multimodal particle mixtures include US 5,518,996, US 7,784,541, US 7,789,146, US 8,008,234, US 8,119,574, US 8,210,249, US 2010/0300688, US 2012/0000641, US 2012/0138296, US 2012/0132421, US 2012/0111563, WO 2012/054456, US 2012/0305245, US 2012/0305254, US 2012/0132421, WO2013085412 and US20130233542, each of which are hereby incorporated herein by reference.

[0078] “Solids” and “solids volume” refer to all solids present in the slurry, including proppant and subproppant particles, including particulate thickeners such as colloids and submicron particles. “Solids-free” and similar terms generally exclude proppant and subproppant particles, except particulate thickeners such as colloids for the purposes of determining the viscosity of a “solids-free” fluid.

[0079] The proppant, when present, can be naturally occurring materials, such as sand grains. The proppant, when present, can also be man-made or specially engineered, such as coated (including resin-coated) sand, modulus of various nuts, high-strength ceramic materials like sintered bauxite, etc. In some embodiments, the proppant of the current application, when present, has a density greater than 2.45 g/mL, e.g., 2.5 – 2.8 g/mL, such as sand, ceramic, sintered bauxite or resin coated proppant. In some embodiments, the proppant of the current application, when present, has a density greater than or equal to 2.8 g/mL, and/or the treatment fluid may comprise an apparent specific gravity less than 1.5, less than 1.4, less than 1.3, less than 1.2, less than 1.1, or less than 1.05, less than 1, or less than 0.95, for example. In some embodiments a relatively large density difference between the proppant and carrier fluid may enhance proppant settling during the clustering phase, for example.

[0080] In some embodiments, the proppant of the current application, when present, has a density less than or equal to 2.45 g/mL, such as light/ultralight proppant from various manufacturers, e.g., hollow proppant. In some embodiments, the treatment fluid comprises an apparent specific gravity greater than 1.3, greater than 1.4, greater than 1.5, greater than 1.6, greater than 1.7, greater than 1.8, greater than 1.9, greater than 2, greater than 2.1, greater than 2.2, greater than 2.3, greater than 2.4, greater than 2.5, greater than 2.6, greater than 2.7, greater than 2.8, greater than 2.9, or greater than 3. In some embodiments where the proppant may be buoyant, i.e., having a specific gravity less than that of the carrier fluid, the term “settling” shall also be inclusive of upward settling or floating.

[0081] “Stable” or “stabilized” or similar terms refer to a concentrated blend slurry (CBS) wherein gravitational settling of the particles is inhibited such that no or minimal free liquid is formed, and/or there is no or minimal rheological variation among strata at different depths in the CBS, and/or the slurry may generally be regarded as stable over the duration of expected CBS storage and use conditions, e.g., a CBS that passes a stability test or an equivalent thereof. In an embodiment, stability can be evaluated following different settling conditions, such as for example static under gravity alone, or dynamic under a vibratory influence, or dynamic-static conditions employing at least one dynamic settling condition followed and/or preceded by at least one static settling condition.

[0082] The static settling test conditions can include gravity settling for a specified period, e.g., 24 hours, 48 hours, 72 hours, or the like, which are generally referred to with the respective shorthand notation “24h-static”, “48h-static” or “72h static”. Dynamic settling test conditions generally indicate the vibratory frequency and duration, e.g., 4h@15Hz (4 hours at 15Hz), 8h@5Hz (8 hours at 5Hz), or the like. Dynamic settling test conditions are at a vibratory amplitude of 1 mm vertical displacement unless otherwise indicated. Dynamic-static settling test conditions will indicate the settling history preceding analysis including the total duration of vibration and the final period of static conditions, e.g.,

4h@15Hz/20h-static refers to 4 hours vibration followed by 20 hours static, or 8h@15Hz/10d-static refers to 8 hours total vibration, e.g., 4 hours vibration followed by 20 hours static followed by 4 hours vibration, followed by 10 days of static conditions. In the absence of a contrary indication, the designation
5 “8h@15Hz/10d-static” refers to the test conditions of 4 hours vibration, followed by 20 hours static followed by 4 hours vibration, followed by 10 days of static conditions. In the absence of specified settling conditions, the settling condition is 72 hours static. The stability settling and test conditions are at 25°C unless otherwise specified.

10 **[0083]** As used herein, a concentrated blend slurry (CBS) may meet at least one of the following conditions:

(1) the slurry has a low-shear viscosity equal to or greater than 1 Pa-s (5.11 s^{-1} , 25°C);

15 (2) the slurry has a Herschel-Bulkley (including Bingham plastic) yield stress (as determined in the manner described herein) equal to or greater than 1 Pa; or

(3) the largest particle mode in the slurry has a static settling rate less than 0.01 mm/hr; or

20 (4) the depth of any free fluid at the end of a 72-hour static settling test condition or an 8h@15Hz/10d-static dynamic settling test condition (4 hours vibration followed by 20 hours static followed by 4 hours vibration followed finally by 10 days of static conditions) is no more than 2% of total depth; or

25 (5) the apparent dynamic viscosity (25°C, 170 s^{-1}) across column strata after the 72-hour static settling test condition or the 8h@15Hz/10d-static dynamic settling test condition is no more than +/- 20% of the initial dynamic viscosity; or

(6) the slurry solids volume fraction (SVF) across the column strata below any free water layer after the 72-hour static settling test condition or the 8h@15Hz/10d-static dynamic settling test condition is no more than 5% greater than the initial SVF; or

5 (7) the density across the column strata below any free water layer after the 72-hour static settling test condition or the 8h@15Hz/10d-static dynamic settling test condition is no more than 1% of the initial density.

[0084] In some embodiments, the concentrated blend slurry comprises at least one of the following stability indicia: (1) an SVF of at least 0.4 up to $SVF = PVF$; (2) a low-shear viscosity of at least 1 Pa-s (5.11 s^{-1} , 25°C); (3) a yield stress (as
10 determined herein) of at least 1 Pa; (4) an apparent viscosity of at least 50 mPa-s (170 s^{-1} , 25°C); (5) a multimodal solids phase; (6) a solids phase having a PVF greater than 0.7; (7) a viscosifier selected from viscoelastic surfactants, in an amount ranging from 0.01 up to 7.2 g/L (60 ppt), and hydratable gelling agents in
15 an amount ranging from 0.01 up to 4.8 g/L (40 ppt) based on the volume of fluid phase; (8) colloidal particles; (9) a particle-fluid density delta less than 1.6 g/mL, (e.g., particles having a specific gravity less than 2.65 g/mL, carrier fluid having a density greater than 1.05 g/mL or a combination thereof); (10) particles having an aspect ratio of at least 6; (11) ciliated or coated proppant; and (12) combinations
20 thereof.

[0085] In an embodiment, the concentrated blend slurry is formed (stabilized) by at least one of the following slurry stabilization operations: (1) introducing sufficient particles into the slurry or treatment fluid to increase the SVF of the treatment fluid to at least 0.4; (2) increasing a low-shear viscosity of the slurry or
25 treatment fluid to at least 1 Pa-s (5.11 s^{-1} , 25°C); (3) increasing a yield stress of the slurry or treatment fluid to at least 1 Pa; (4) increasing apparent viscosity of the slurry or treatment fluid to at least 50 mPa-s (170 s^{-1} , 25°C); (5) introducing a multimodal solids phase into the slurry or treatment fluid; (6) introducing a solids phase having a PVF greater than 0.7 into the slurry or treatment fluid; (7)
30 introducing into the slurry or treatment fluid a viscosifier selected from

viscoelastic surfactants, e.g., in an amount ranging from 0.01 up to 7.2 g/L (60 ppt), and hydratable gelling agents, e.g., in an amount ranging from 0.01 up to 4.8 g/L (40 ppt) based on the volume of fluid phase; (8) introducing colloidal particles into the slurry or treatment fluid; (9) reducing a particle-fluid density delta to less than 1.6 g/mL (e.g., introducing particles having a specific gravity less than 2.65 g/mL, carrier fluid having a density greater than 1.05 g/mL or a combination thereof); (10) introducing particles into the slurry or treatment fluid having an aspect ratio of at least 6; (11) introducing ciliated or coated proppant into slurry or treatment fluid; and (12) combinations thereof. The slurry stabilization operations may be separate or concurrent, e.g., introducing a single viscosifier may also increase low-shear viscosity, yield stress, apparent viscosity, etc., or alternatively or additionally with respect to a viscosifier, separate agents may be added to increase low-shear viscosity, yield stress and/or apparent viscosity.

[0086] Increasing carrier fluid viscosity in a Newtonian fluid also proportionally increases the resistance of the carrier fluid motion. In some embodiments, the carrier fluid has a lower limit of apparent dynamic viscosity, determined at 170 s^{-1} and 25°C , of at least about 10 mPa-s, or at least about 25 mPa-s, or at least about 50 mPa-s, or at least about 75 mPa-s, or at least about 100 mPa-s, or at least about 150 mPa-s, or at least about 300 mPa-s, or at least about 500 mPa-s. A disadvantage of increasing the viscosity is that as the viscosity increases, the friction pressure for pumping the slurry generally increases as well. In some embodiments, the fluid carrier has an upper limit of apparent dynamic viscosity, determined at 170 s^{-1} and 25°C , of less than about 1000 mPa-s, or less than about 500 mPa-s, or less than about 300 mPa-s, or less than about 150 mPa-s, or less than about 100 mPa-s, or less than about 50 mPa-s. In an embodiment, the fluid phase viscosity ranges from any lower limit to any higher upper limit.

[0087] In some embodiments, an agent may both viscosify and impart yield stress characteristics, and in further embodiments may also function as a friction reducer to reduce friction pressure losses in pumping the treatment fluid. In an

embodiment, the liquid phase is essentially free of viscosifier or comprises a viscosifier in an amount ranging from 0.01 up to 12 g/L (0.08 – 100 ppt) of the fluid phase. The viscosifier can be a viscoelastic surfactant (VES) or a hydratable gelling agent such as a polysaccharide, which may be crosslinked.

5 When using viscosifiers and/or yield stress fluids, proppant settling in some embodiments may be triggered by breaking the fluid using a breaker(s). In some embodiments, the slurry is stabilized for storage and/or pumping or other use at the surface conditions and proppant transport and placement, and settlement triggering is achieved downhole at a later time prior to fracture closure, which
10 may be at a higher temperature, e.g., for some formations, the temperature difference between surface and downhole can be significant and useful for triggering degradation of the viscosifier, any stabilizing particles (e.g., subproppant particles) if present, a yield stress agent or characteristic, and/or a activation of a breaker. Thus in some embodiments, breakers that are either
15 temperature sensitive or time sensitive, either through delayed action breakers or delay in mixing the breaker into the slurry to initiate destabilization of the slurry and/or proppant settling, can be useful.

[0088] In embodiments, the fluid may include leakoff control agents, such as, for example, latex dispersions, water soluble polymers, submicron particulates,
20 particulates with an aspect ratio higher than 1, or higher than 6, combinations thereof and the like, such as, for example, crosslinked polyvinyl alcohol microgel. The fluid loss agent can be, for example, a latex dispersion of polyvinylidene chloride, polyvinyl acetate, polystyrene-co-butadiene; a water soluble polymer such as hydroxyethylcellulose (HEC), guar, copolymers of polyacrylamide and
25 their derivatives; particulate fluid loss control agents in the size range of 30 nm to 1 micron, such as γ -alumina, colloidal silica, CaCO_3 , SiO_2 , bentonite etc.; particulates with different shapes such as glass fibers, flocs, flakes, films; and any combination thereof or the like. Fluid loss agents can if desired also include or be used in combination with acrylamido-methyl-propane sulfonate polymer
30 (AMPS). In an embodiment, the leak-off control agent comprises a reactive solid,

e.g., a hydrolyzable material such as PGA, PLA or the like; or it can include a soluble or solubilizable material such as a wax, an oil-soluble resin, or another material soluble in hydrocarbons, or calcium carbonate or another material soluble at low pH; and so on. In an embodiment, the leak-off control agent comprises a reactive solid selected from ground quartz, oil soluble resin, degradable rock salt, clay, zeolite or the like. In other embodiments, the leak-off control agent comprises one or more of magnesium hydroxide, magnesium carbonate, magnesium calcium carbonate, calcium carbonate, aluminum hydroxide, calcium oxalate, calcium phosphate, aluminum metaphosphate, sodium zinc potassium polyphosphate glass, and sodium calcium magnesium polyphosphate glass, or the like. The treatment fluid may also contain colloidal particles, such as, for example, colloidal silica, which may function as a loss control agent, gellant and/or thickener.

[0089] In embodiments, the proppant-containing treatment fluid may comprise from 0.06 or 0.12 g of proppant per mL of treatment fluid (corresponding to 0.5 or 1 ppa) up to 1.2 or 1.8 g/mL (corresponding to 10 or 15 ppa). In some embodiments, the proppant-laden treatment fluid may have a relatively low proppant loading in earlier-injected fracturing fluid and a relatively higher proppant loading in later-injected fracturing fluid, which may correspond to a relatively narrower fracture width adjacent a tip of the fracture and a relatively wider fracture width adjacent the wellbore. For example, the proppant loading may initially begin at 0.48 g/mL (4 ppa) and be ramped up to 0.6 g/mL (6 ppa) at the end.

[0090] In some embodiments, where the macrostructures are made from a gel ball material, the gel ball material may be presheared prior to mixing with the base fluid, and/or the base fluid and material suitable for forming the ball may be mixed together in an appropriate mixer to provide the proper shear and other conditions to obtain the gel bodies of the desired size and distribution, such as, for one example, at a ratio of 70 to 95% by volume of proppant or other solid

particulate to 5 to 30% by volume of gel body material, e.g., 85% to 15%, based on the total volume of gel body material and solid particulate(s).

[0091] The treatment fluid in some embodiments may also contain a breaker for the viscoelastic carrier fluid to lower the viscosity after the fluid is placed in the fracture, prior to or after fracture closure. The change in viscosity in these
5 embodiments allows the solid particles such as sand or other proppant to settle on top of the gel bodies, where the gel bodies, due to their higher viscosity and size, are anchored in the formation and capture the solid particulate to create clusters. In these embodiments, the clusters maintain the fracture open after
10 closure stress is applied while the space surrounding the clusters is left free of proppant to create channels. Additional breaker may be employed in some embodiments to fully break the carrier fluid and/or to break the gel body material after fracture closure to create conductive pathways.

[0092] This channelization phenomenon of some embodiments is observed in
15 Figs. 2A-2C. In Fig. 2A, immediately following injection of the treatment fluid(s), the generally vertically oriented fracture 40 may contain a fairly even or homogenous distribution of proppant particles 42 and gel bodies 44. In Fig. 2B, settlement of the proppant in the fracture 42, e.g., prior to closure, has aggregated the proppant and resulted in the formation of proppant clusters 46 on
20 the upper surfaces of the immobilized gel bodies 44. Then after closure as seen in Fig. 2C, conductive paths 48 are formed between the clusters 46.

[0093] In other embodiments, after the fluid is pumped into the fracture 50 to distribute the particulate slurry 52 and gel bodies 54 as seen in Fig. 3A, the closure stress is applied on the gel bodies 54 which expand radially and may
25 connect laterally to one or more adjacent gel bodies 54 as seen in Fig. 3B, and the gel bodies 54 may then be broken to form a connected flow path 56 along the profiles 58 of the respective gel bodies, as seen in Fig. 3C.

[0094] For example, the gel body breaker may contact the gel bodies 54 when the stress from the formation is applied, lowering the viscosity of the gel bodies

54 and allowing them to flow, e.g., into the formation and/or toward the wellbore during flowback. In some embodiments, e.g., where closure stress may not be sufficient to break a frangibly encapsulated breaker, a thermally sensitive encapsulant such as an encapsulated acid may additionally or alternatively be used as a breaker, whereby the temperature trigger releases the acid, lowers the pH and de-crosslinks the polymer in the gel bodies. When the gel bodies break, the resulting voided spaces may create a network of channels. In these embodiments, the carrier fluid may or may not be broken before the fracture closure, proppant may or may not settle and aggregate to form clusters, and the carrier fluid may or may not be lost to the formation through natural fractures, surface wetting or low fluid loss control properties of the fluid.

[0095] In some embodiments, as mentioned, the gel bodies can also be formulated to optionally contain fibers, proppant at relatively high concentration, e.g., 0.6 g/mL (5 ppa) or more, or a combination thereof, referred to herein as composite gel bodies. These composite gel bodies in some embodiments are incorporated in a viscous base fluid and pumped in a fracturing treatment. The base fluid in some embodiments may optionally contain fiber, proppant or a combination of both. After placement, the fluid used to carry these gel bodies can be leaked off into the formation or flowed back as the fracture is closing. The gel bodies, however, may be retained in the fracture due to a large size relative to the fracture width and/or high viscosity relative to the carrier fluid. When the fracture closes in some embodiments, the gel bodies made with proppant and/or fiber may act as or reinforce the proppant clusters to facilitate holding the fracture open and improve conductivity.

[0096] In some embodiments, changes in salinity concentrations between the composite gel bodies and the formation brine may be used to shrink the gel bodies to give higher solid concentration and thus thicker pillars. These solid laden gel bodies in some embodiments may be sufficiently strong and stiff to support and prop the fracture open upon closure, i.e., the composite gel bodies may function as proppant and/or as a proppant adjunct. In some embodiments,

channels may be formed surrounding the composite bodies, with high conductivity for production.

[0097] According to some embodiments herein, the macrostructures may form “shelves” on their upper surfaces, which may be distributed along the fracture height and length. Where the fracture(s) generally has a variable width depending on the distance from the well and wall surface imperfections, the macrostructures in some embodiments, may have a range of different sizes to be effectively placed between the fracture walls in different locations, e.g., larger macrostructures where the fracture is wider and smaller macrostructures where the fracture is narrower. The macrostructures in some embodiments may not have a substantial compaction strength, and in some embodiments the macrostructures may have a specific gravity comparable to the carrier fluid or be nearly neutrally buoyant, e.g., 95 to 100% of the specific gravity of the carrier fluid.

[0098] In some embodiments, the cumulative surface area of the terraces, or the horizontal projection area, provided by the macrostructures, determines the amount of proppant that can be retained on them. On the other hand, too high macrostructure concentrations in a slurry may lead to plugging of the perforations or fractures during injection or attempted injection. While the macrostructure shape is not limited herein and can be any appropriate for the particular application, in some embodiments the shape is elongated with high aspect ratio. For spherical macrostructure 60 the ratio of horizontal projection area to volume comprises $3/2d$ as seen in Fig. 4, where d is the diameter of the sphere; for transverse disc macrostructure 70, $4/\pi D$ as seen in Fig. 5, where D is the diameter and d is the thickness; whereas the horizontal elongated cylindrical macrostructure 80, with diameter d and length l as seen in Fig. 6, has a projection area/volume ratio expressed as $4/\pi d$.

[0099] The macrostructure particles 80 in some embodiments may be oriented horizontally in the flow of the carrier fluid during pumping, so they will naturally form shelves when stuck in the fracture. Furthermore, while proppant covers

substantially the entire top surface of an elongated particle, significantly less proppant is held by a spherical or disc-shaped particle, e.g., at the margins where the slope of the macrostructure exceeds the angle of repose. The proppant pillar volume also depends on the material angle of repose, which for most of fracturing sands and proppants in some embodiments is in the range of 27-35°. It is important to find an optimal additive concentration in the slurry. It is possible to evaluate concentration based on volume balance between additive material and proppant, as illustrated in the examples below.

[00100] In some embodiments according to the disclosure herein, an in situ method and system are provided for increasing fracture conductivity. By “in situ” is meant that channels of relatively high hydraulic conductivity are formed in a fracture after it has been filled with proppant particles, which in some embodiments, may be injected at a generally continuous proppant particle concentration. As used herein, a “hydraulically conductive fracture” is one which has a high conductivity relative to the adjacent formation matrix, whereas the term “conductive channel” refers to both open channels as well as channels filled with a matrix having interstitial spaces for permeation of fluids through the channel, such that the channel has a relatively higher conductivity than adjacent non-channel areas.

[00101] The term “continuous” in reference to concentration or other parameter as a function of another variable such as time, for example, means that the concentration or other parameter is an uninterrupted or unbroken function, which may include relatively smooth increases and/or decreases with time, e.g., a smooth rate or concentration of proppant particle introduction into a fracture such that the distribution of the proppant particles is free of repeated discontinuities and/or heterogeneities over the extent of proppant particle filling. In some embodiments, a relatively small step change in a function is considered to be continuous where the change is within +/- 10% of the initial function value, or within +/- 5% of the initial function value, or within +/- 2% of the initial function value, or within +/- 1% of the initial function value, or the like over a period of time

of 1 minute, 10 seconds, 1 second, or 1 millisecond. The term “repeated” herein refers to an event which occurs more than once in a stage.

[00102] Conversely, a parameter as a function of another variable such as time, for example, is “discontinuous” wherever it is not continuous, and in some embodiments, a repeated relatively large step function change is considered to be discontinuous, e.g., where the lower one of the parameter values before and after the step change is less than 80%, or less than 50%, or less than 20%, or less than 10%, or less than 5%, or less than 2% or less than 1%, of the higher one of the parameter values before and after the step change over a period of time of 1 minute, 10 seconds, 1 second, or 1 millisecond.

[00103] In embodiments, the conductive channels are formed in situ after placement of the proppant particles in the fracture by differential movement of the proppant particles, e.g., by gravitational settling and/or fluid movement such as fluid flow initiated by a flowback operation, out of and/or away from an area(s) corresponding to the conductive channel(s) and into or toward spaced-apart areas in which clustering of the proppant particles results in the formation of relatively less conductive areas, which clusters may correspond to pillars between opposing fracture faces upon closure.

[00104] In some embodiments, a treatment slurry stage has a continuous concentration of a first solid particulate, e.g., proppant, and a discontinuous concentration of the microstructures that facilitates either clustering of the first solid particulate in the fracture, or anchoring of the clusters in the fracture, or a combination thereof, to form anchored clusters of the solid particulate to prop open the fracture upon closure. As used herein, an “anchorant” refers to a material, a precursor material, or a mechanism, that inhibits settling, or preferably stops settling, of particulates or clusters of particulates in a fracture, whereas an “anchor” refers to an anchorant such as a microstructure that is active or activated to inhibit or stop the settling.

[00105] In some embodiments, the microstructure may adhere to one or both opposing surfaces of the fracture to stop movement of a proppant particle cluster and/or to provide immobilized structures upon which proppant or proppant cluster(s) may accumulate. In some embodiments, the microstructures may
5 adhere to each other to facilitate consolidation, stability and/or strength of the formed clusters.

[00106] In some embodiments, the microstructure may comprise a continuous concentration of a first anchorant component and a discontinuous concentration of a second anchorant component, e.g., where the first and second
10 anchorant components may react to form the microstructures as in a two-reactant system, a catalyst/reactant system, a pH-sensitive reactant/pH modifier system, or the like.

[00107] In some embodiments, the microstructure may form lower boundaries for particulate settling.

[00108] In some embodiments, a method for treating a subterranean formation penetrated by a wellbore comprises: injecting a treatment stage fluid above a fracturing pressure to form a fracture in the formation; continuously distributing a first solid particulate into the formation in the treatment stage fluid; aggregating the first solid particulate distributed into the fracture to form spaced-
15 apart clusters in the fracture; anchoring at least some of the clusters in the fracture to inhibit aggregation of at least some of the clusters; reducing pressure in the fracture to prop the fracture open on the clusters and form interconnected, hydraulically conductive channels between the clusters.
20

[00109] In some embodiments, the first solid particulate continuously distributed in the treatment stage fluid comprises disaggregated proppant at a continuous concentration. In some embodiments, the aggregation comprises triggering settling of the distributed first solid particulate. In some embodiments, the method further comprises viscosifying the treatment stage fluid for distributing the first solid particulate into the formation, and breaking the treatment stage fluid
25

in the fracture to trigger the settling. In some embodiments, the method further comprises successively alternating concentration modes of a microstructure in the treatment stage fluid between a relatively microstructure-rich mode and an microstructure-lean mode during the continuous distribution of the first solid particulate into the formation in the treatment stage fluid to facilitate one or both of the cluster aggregation and anchoring.

[00110] In some embodiments, the microstructure-lean concentration mode is free or essentially free of microstructure, or a difference between the concentrations of the microstructure-rich and microstructure-lean modes is at least 10, or at least 25, or at least 40, or at least 50, or at least 60, or at least 75, or at least 80, or at least 90, or at least 95, or at least 98, or at least 99, or at least 99.5 weight percent of the microstructure concentration of the microstructure-rich mode. A microstructure-lean mode is essentially free of microstructure if the concentration of microstructure is less than 0.5 percent based on the volume of the microstructure concentration of the microstructure rich mode.

[00111] In some embodiments, the conductive channels extend in fluid communication from adjacent a face of in the formation away from the wellbore to or to near the wellbore, e.g., to facilitate the passage of fluid between the wellbore and the formation, such as in the production of reservoir fluids and/or the injection of fluids into the formation matrix. As used herein, "near the wellbore" refers to conductive channels coextensive along a majority of a length of the fracture terminating at a permeable matrix between the conductive channels and the wellbore, e.g., where the region of the fracture adjacent the wellbore is filled with a permeable solids pack as in a high conductive proppant tail-in stage, gravel packing or the like.

[00112] In some embodiments, a method for treating a subterranean formation penetrated by a wellbore comprises: injecting into a fracture in the formation at a continuous rate a treatment fluid stage with a continuous first solid particulate concentration; while maintaining the continuous rate and first solid

particle concentration during injection of the treatment fluid stage, successively alternating concentration modes of a microstructure in the treatment fluid stage between a plurality of relatively microstructure-rich modes and a plurality of microstructure-lean modes within the injected treatment fluid stage.

5 **[00113]** In some embodiments, the injection of the treatment fluid stage forms a homogenous region within the fracture of continuously uniform distribution of the first solid particulate. In some embodiments, the alternation of the concentration of the microstructure forms heterogeneous areas within the fracture comprising microstructure-rich areas and microstructure-lean areas.

10 **[00114]** In some embodiments, the injected treatment fluid stage comprises a viscosified carrier fluid, and the method may further comprise reducing the viscosity of the carrier fluid in the fracture to induce settling of the first solid particulate prior to closure of the fracture, and thereafter allowing the fracture to close.

15 **[00115]** In some embodiments, the method may also include forming bridges or terraces with the microstructures in the fracture and forming conductive channels between the bridges with the microstructure-lean modes.

20 **[00116]** In some embodiments, a method for treating a subterranean formation penetrated by a wellbore comprises: injecting into a fracture in the formation at a continuous rate a treatment fluid stage comprising a viscosified carrier fluid with a continuous first solid particulate concentration and a continuous microstructure concentration to form a homogenous region within the fracture of continuously uniform distribution of the first solid particulate and the microstructures; reducing the viscosity of the carrier fluid within the homogenous
25 region to induce settling of the first solid particulate prior to closure onto the microstructures to form pillars in corresponding to clusters of the settled first solid particulate and channels corresponding to areas from which the first solid particulate has settled; and thereafter allowing the fracture to close onto the pillars.

[00117] In some embodiments, the microstructure may comprise a degradable material. In some embodiments, the microstructure is selected from the group consisting of polylactic acid (PLA), polyglycolic acid (PGA), polyethylene terephthalate (PET), polyester, polyamide, polycaprolactam and polylactone, poly(butylene succinate), polydioxanone, glass, ceramics, carbon (including carbon-based compounds), elements in metallic form, metal alloys, wool, basalt, acrylic, polyethylene, polypropylene, novoloid resin, polyphenylene sulfide, polyvinyl chloride, polyvinylidene chloride, polyurethane, polyvinyl alcohol, polybenzimidazole, polyhydroquinone-diimidazopyridine, poly(p-phenylene-2,6-benzobisoxazole), rayon, cotton, or other natural fibers, rubber, sticky fiber, or a combination thereof. In some embodiments the microstructure may comprise acrylic fiber. In some embodiments the microstructure may comprise mica.

[00118] In some embodiments, the microstructure is present in the microstructure-laden stages of the treatment slurry in an amount of less than 5 vol%. All individual values and subranges from less than 5 vol% are included and disclosed herein. For example, the amount of microstructure may be from 0.05 vol% less than 5 vol%, or less than 1 vol%, or less than 0.5 vol%. The microstructure may be present in an amount from 0.5 vol% to 1.5 vol%, or in an amount from 0.01 vol% to 0.5 vol%, or in an amount from 0.05 vol% to 0.5 vol%.

[00119] In further embodiments, the microstructure may comprise a fiber with a length from 1 to 50 mm, or more specifically from 1 to 10mm, and a diameter of from 1 to 50 microns, or, more specifically from 1 to 20 microns. All values and subranges from 1 to 50 mm are included and disclosed herein. For example, the fiber microstructure length may be from a lower limit of 1, 3, 5, 7, 9, 19, 29 or 49 mm to any higher upper limit of 2, 4, 6, 8, 10, 20, 30 or 50 mm. The fiber microstructure length may range from 1 to 50 mm, or from 1 to 10 mm, or from 1 to 7 mm, or from 3 to 10 mm, or from 2 to 8 mm. All values from 1 to 50 microns are included and disclosed herein. For example, the fiber microstructure diameter may be from a lower limit of 1, 4, 8, 12, 16, 20, 30, 40, or 49 microns to

an upper limit of 2, 6, 10, 14, 17, 22, 32, 42 or 50 microns. The fiber microstructure diameter may range from 1 to 50 microns, or from 10 to 50 microns, or from 1 to 15 microns, or from 2 to 17 microns.

[00120] In further embodiments, the microstructure may be fiber selected from the group consisting of polylactic acid (PLA), polyester, polycaprolactam, polyamide, polyglycolic acid, polyterephthalate, cellulose, wool, basalt, glass, rubber, or a combination thereof.

[00121] In further embodiments, the microstructure may comprise a fiber with a length from 0.001 to 1 mm and a diameter of from 50 nanometers (nm) to 10 microns. All individual values from 0.001 to 1 mm are disclosed and included herein. For example, the microstructure fiber length may be from a lower limit of 0.001, 0.01, 0.1 or 0.9 mm to any higher upper limit of 0.009, 0.07, 0.5 or 1 mm. All individual values from 50 nanometers to 10 microns are included and disclosed herein. For example, the fiber microstructure diameter may range from a lower limit of 50, 60, 70, 80, 90, 100, or 500 nanometers to an upper limit of 500 nanometers, 1 micron, or 10 microns.

[00122] In some embodiments, the microstructure may comprise an expandable material, such as, for example, swellable elastomers, temperature expandable particles. Examples of oil swellable elastomers include butadiene based polymers and copolymers such as styrene butadiene rubber (SBR), styrene butadiene block copolymers, styrene isoprene copolymer, acrylate elastomers, neoprene elastomers, nitrile elastomers, vinyl acetate copolymers and blends of EV A, and polyurethane elastomers. Examples of water and brine swellable elastomers include maleic acid grafted styrene butadiene elastomers and acrylic acid grafted elastomers. Examples of temperature expandable particles include metals and gas filled particles that expand more when the particles are heated relative to silica sand. In some embodiments, the expandable metals can include a metal oxide of Ca, Mn, Ni, Fe, etc. that reacts with the water to generate a metal hydroxide which has a lower density than the metal oxide, i.e., the metal hydroxide occupies more volume than the metal oxide

thereby increasing the volume occupied by the particle. Further examples of swellable inorganic materials can be found in U.S. Application Publication Number US 20110098202, which is hereby incorporated by reference in its entirety. An example for gas filled material is EXPANCEL™ microspheres that are manufactured by and commercially available from Akzo Nobel of Chicago, IL. These microspheres contain a polymer shell with gas entrapped inside. When these microspheres are heated the gas inside the shell expands and increases the size of the particle. The diameter of the particle can increase 4 times which could result in a volume increase by a factor of 64.

[00123] In some embodiments, the ability of the fracturing fluid to suspend the proppant is reduced after finishing the fracturing treatment and before fracture closure to a level which triggers gravitational settling of the propping agent inside the fracture. For example, the fracturing fluid may be stabilized during placement with a viscosified carrier fluid and destabilized by breaking the viscosity after placement in the fracture and before closure. Proppant settling results in the creation of heterogeneity of proppant distribution inside the fracture because the rate of proppant settling in presence of fiber is significantly slower than without fiber. At some certain concentrations of fiber and propping agent according to embodiments herein, it is possible to enable the creation of stable interconnected proppant free areas and proppant rich clusters which in turn enables high conductivity of the fracture after its closure.

EXAMPLES

[00124] **Example 1:** demonstration of concentration evaluation based on volume balance between cylindrical macrostructures and proppant. In the case of the elongate cylinder shown in Fig. 7, the volume of the cylinder shelf, V_a , is given in Eq. 1:

$$V_a = l \cdot \pi d^2 / 4 \quad (1)$$

where l is the length and d is the diameter of the cylinder, which is also just equal to the width of the fracture in this example. The volume of the proppant heap on the top is given by Eq. 2:

$$V_{heap} = d \cdot l^2 \tan \alpha / 4 \quad (2)$$

5 where α is the angle of repose of the proppant.

[00125] Considering porosity of proppant pack as φ , the proppant volume V_p in the heap is given by Eq. 3:

$$V_p = (1 - \varphi) \cdot V_{heap} = (1 - \varphi) \cdot d \cdot l^2 \tan \alpha / 4 \quad (3)$$

[00126] If volumetric proppant concentration (fraction) in the slurry is denoted as C_p , then optimal volumetric concentration of additive material C_a can be defined according to the formula given in Eq. 4:

$$C_a = C_p \cdot \frac{V_a}{V_p} \text{ or } C_a = C_p \cdot \frac{\pi d \varphi}{l \tan \alpha} \quad (4)$$

[00127] This concentration ratio in this example is based on the assumption that all macrostructures are covered with proppant and all proppant is accumulated on the terraces. The cylindrical macrostructures are also assumed for the purpose of this example to be oriented horizontally in the flow and once the particle sticks between the fracture walls its orientation does not change, as it provides minimum resistance to flow.

[00128] Eq. (4) establishes the ratio between required volume concentration of additive and volume concentration of proppant. For certain proppant material volume and mass of additive can be calculated. In this example, the proppant is sand with a density of 2.65 g/cm³, pack porosity 0.35, and angle of repose 30°; the macrostructures are cylinders with length of 25 mm, diameter 5 mm and have density equal to 1.2 g/cm³. Then volume and mass ratios will then be as follows in Eqs. 5-7:

$$C_a = C_p \cdot \frac{\pi d (1 - \varphi)}{l \tan \alpha} = C_p \cdot \frac{3.14 \cdot 0.5 \cdot (1 - 0.35)}{2.5 \cdot 0.58} = 0.7 \cdot C_p \quad (5)$$

$$0.7 = \frac{C_a}{C_p} = \frac{V_a}{V_p} = \frac{M_a/\rho_a}{M_p/\rho_p} \quad (6)$$

$$M_a = 0.7 \cdot \frac{\rho_a}{\rho_p} \cdot M_p = 0.7 \cdot \frac{1.2}{2.65} \cdot M_p = 0.32 \cdot M_p \quad (7)$$

where M_a is the macrostructures mass, M_p is the proppant mass, ρ_a is density of the macrostructures material, ρ_p is density of the proppant material. Eq. 7 provides the mass ratio. In other words, for every 1000 kg of sand/proppant, 320 kg of macrostructures are required. Note that the mass of sand/proppant required to achieve the same fracture conductivity in case of heterogeneous proppant placement can be 30-50% less than in case of conventional proppant placement.

[00129] The ratio of Eq. 7 strongly depends on the shape of additive particles. For the same diameter additive particles, but with 50 mm length, the ratio between volume concentrations (Eq. 8) will be different as well as the mass ratio (Eq. 9):

$$C_a = C_p \cdot \frac{\pi d(1-\varphi)}{l \tan \alpha} = C_p \cdot \frac{3.14 \cdot 0.5 \cdot (1-0.35)}{5 \cdot 0.58} = 0.35 \cdot C_p \quad (8)$$

$$M_a = 0.35 \cdot \frac{\rho_a}{\rho_p} \cdot M_p = 0.35 \cdot \frac{1.2}{2.65} \cdot M_p = 0.16 \cdot M_p \quad (9)$$

Thus the required number of 50 mm macrostructures is four time less than the required number of 25 mm ones. Obviously, the mass of the cylinder depends on its length linearly and the mass of the proppant heap on the top is proportional to the squared cylinder length and density. Particles are not required to be high stress and crush resistant.

[00130] Example 2: This example is based on a laboratory experiment using fragments of soda straw to represent tubular macrostructures, having a length of 20 mm, diameter 5 mm, thickness of the wall 0.1 mm, density 0.95 g/cm³. Sand 70/140 US mesh (density 2.65 g/cm³, porosity of pack 0.35) and mica 70/140 US (density 2.8 g/cm³, porosity of pack 0.15) were used as proppant.

[00131] The tubes were placed horizontally between the walls of a settling PLEXIGLAS polycarbonate slot. The slot was then filled with water. Proppant was poured from the top of the slot. The heaps formed on the tubes were measured. In case of sand which had an angle of repose close to 30°, the
5 volume heap is calculated in Eq. 10:

$$V_{heap} = d \cdot \frac{l^2 \tan \alpha}{4} = 5 \cdot 20 \cdot 20 \cdot \frac{0.58}{4} = 290 \text{ mm}^3 \quad (10)$$

[00132] Taking into account porosity of the proppant pack, the volume of proppant in the heap is calculated in Eq. 11:

$$V_p = (1 - \varphi) \cdot V_{heap} = (1 - 0.65) \cdot 290 = 101.5 \text{ mm}^3 \quad (11)$$

10 **[00133]** The volume of the tube (just walls without void space) is calculated in Eq. 12:

$$V_a = l \cdot \pi \cdot \frac{(d^2 - (d - \Delta d)^2)}{4} = 20 \cdot 3.14 \cdot \frac{25 - 24}{4} = 15.7 \text{ mm}^3 \quad (12)$$

[00134] Taking into account densities of materials the following mass ratios occur in Eqs. 13 and 14:

$$15 \quad M_a = 0.35 \cdot \frac{\rho_a}{\rho_p} \cdot M_p = 0.35 \cdot \frac{1.2}{2.65} \cdot M_p = 0.16 \cdot M_p \quad (13)$$

$$M_a = \frac{V_a}{V_p} \cdot \frac{\rho_a}{\rho_p} \cdot M_p = \frac{15.7}{101.5} \cdot \frac{0.95}{2.65} \cdot M_p = 0.055 \cdot M_p \quad (14)$$

[00135] This means that if the macrostructures have a shape of tubes, for each 1000 kg of proppant only 55 kg of macrostructures are required. This value is significantly smaller compared to ratios of Eqs. 7 and 9.

20 **[00136]** For the mica proppant an important observation was made. Since mica particles are plate-like, the heap length is greater than the length of shelf on which the heap lies. Some mica particles stick out of the platform for a distance Δl , they are hold by adjacent particles. The Δl value was measured to be about 1 mm. Volume of the proppant heap is proportional to the square of the
25 base. Angle of repose for mica is about 40°. In this case the volume of proppant in the heap is

$$V_{heap} = d \cdot \frac{(l+2\Delta l)^2 \tan \alpha}{4} = 5 \cdot 22 \cdot 22 \cdot \frac{0.84}{4} = 508.2 \text{ mm}^3 \quad (15)$$

[00137] A heap of mica is significantly bigger than a heap of sand (cf. Eq. 10) in the same conditions, although total mass of proppant in this heap is less because of increased porosity of mica package:

$$5 \quad M_{sand} = (1 - \varphi) \cdot V_{heap} \cdot \rho_{sand} = (1 - 0.65) \cdot 0.290 \cdot 2.65 = 0.27g \quad (16)$$

$$M_{mica} = (1 - \varphi) \cdot V_{heap} \cdot \rho_{mica} = (1 - 0.85) \cdot 0.508 \cdot 2.8 = 0.21g \quad (17)$$

[00138] **Example 3:** In stimulation of a shale reservoir the estimated fracture width during pumping in this example is assumed to be 5 mm near wellbore and is considered to decrease linearly with distance down to 0 mm at 10 500 m. The width is further assumed to be the same along the whole fracture height. Proppant is supposed to be delivered 200 m from the wellbore. Therefore, if macrostructures have cylindrical shape their diameters should be uniformly distributed from 3 mm to 5 mm to cover the area where proppant is going to be placed.

15 **[00139]** **Example 4:** In the following examples, gel ball materials were prepared by hydrating the guar for 10-20 minutes in a 1000 mL Waring blender, adding any fiber or solids to the mixture, and then crosslinking the gel. A 100 g portion of the crosslinked gel was transferred to a 500 mL blender cup and the speed was increased to medium for 1 second, then speed immediately reduced
20 to zero; this was repeated three times for each 100 g of crosslinked gel, and the resulting balls added to the carrier fluid. Most of the gel balls were between 10-13 mm in diameter. The size of the balls is dependent on the shear rate, which could be adjusted in the field to obtain the desired size. In this example the macrostructures were gel balls made with guar at a concentration of 12 g/L (100
25 ppt) and cross-linked with a borate crosslinker. The gel ball material was then mixed in a carrier fluid consisting of a viscoelastic fluid (ClearFRAC XT) containing 20 mL/L (20 gpt) of a 35-40 wt% surfactant solution and 3.3 mL/L (3.3 gpt) of a rheology modifier solution, and also containing PLA fibers at 4.8 g/L (40

ppt) and 0.6 g/mL (5 ppa) of 20/40 mesh sand. The base fluid and gel ball material were mixed at a ratio of 85% by volume of sand to 15% by volume of gel ball material. With reference to Fig. 8A, the mixture was injected into a 152 mm (6-in.) by 203 mm (8 in.) slot 200 with a 3 mm wide gap and a transparent to
5 obtain a more or less random placement of gel balls 202 and distributed proppant 204. Slots used to simulate reservoir fractures in this example had a transparent front plate and sandpaper with a roughness of 100 mesh grit was glued to the back wall of the slot. After 2 hours settling time, as seen in Fig. 8B, the gel balls 202 supported settled proppant 206, creating channels 208 formed under the gel
10 balls 202.

[00140] Example 5: Example 4 was repeated with different carrier fluid and gel ball compositions. In this example the gel ball material was made with crosslinked sodium polyacrylate. The gel ball material was then mixed in a carrier fluid comprising a viscoelastic fluid containing guar at 3 g/L (25 ppt), 0.6 g/mL (5
15 ppa) of 20/40 mesh sand, and 4.8 g/L (40 ppt) of crimped fibers measuring 12.7 mm (0.5 in.) in length and 40 μ m in diameter. The base fluid and gel ball material were mixed at a ratio of 85% by volume of sand to 15% by volume of gel ball material. The mixture was crosslinked with 2 mL/L (2 gpt) borate crosslinker solution, and DBE-5 ester at 70 mL/L (70 gpt), which hydrolyzes at elevated
20 temperatures to form acid, was used to de-crosslink the fluid to linear gel viscosity after placement in a 152 mm (6-in.) by 203 mm (8 in.) slot 200 with a 6 mm wide gap. The gel balls anchored on the rough (non-window) surface of the cell and captured the settling proppant to create clusters. Channels free of proppant were formed surrounding the clusters. The remaining linear gel
25 viscosity was then broken completely with a chemical oxidant breaker to allow for flowback through the formed channels.

[00141] Example 6: This example demonstrates the feasibility of radially expanding gel ball macrostructures at fracture closure to contact adjacent gel balls, and, upon breaking the contacting gel balls, e.g., by releasing
30 encapsulated and/or temperature activated breaker present in the gel balls,

creating flow paths through the gel ball profiles. The carrier was a viscoelastic ClearFRAC XT fluid, made with 20 mL/L (20 gpt) of a 35-40 wt% surfactant solution and 3.3 mL/L (3.3 gpt) of a rheology modifier solution, and also containing PLA fibers at 4.8 g/L (40 ppt) and 2.16 g/mL (18 ppa) of a mixture of 70/140 mesh and 40/70 mesh sand. Gel balls, made from guar at a concentration of 12 g/L (100 ppt) and cross-linked with a borate crosslinker solution at 2 mL/L (2 gpt), and also containing 4.8 g/L (40 ppt) PLA fibers, were added to the fluid. The base fluid and gel ball material were mixed at a ratio of 60% by volume of sand to 40% by volume of gel ball material. The slurry was packed into a 152 mm (6-in.) by 203 mm (8 in.) slot 210 with a 3 mm wide gap to obtain a more or less random placement of gel balls 212 and distributed proppant 214 as seen in Fig. 9A. After 2 hours settling time at room temperature, as seen in Fig. 9B, the gel balls 212 maintained their integrity and position.

[00142] Example 7: In this example, the gel balls were formulated with a combination of fibers and sand at relatively high concentration. The gel balls contained 12 g/L (100 ppt) guar, 2 mL/L (2 gpt) borate crosslinker solution, 4.8 g/L (40 ppt) PLA fibers and 0.36 g/mL (3 ppa) 20/40 mesh sand. The carrier fluid was comprised of only ClearFRAC XT 20, made with 20 mL/L (20 gpt) of a 35-40 wt% surfactant solution and 3.3 mL/L (3.3 gpt) of a rheology modifier solution. The base fluid and gel ball material were mixed at a ratio of 85% by volume of sand to 15% by volume of gel ball material. The slurry was injected into a 152 mm (6-in.) by 203 mm (8 in.) slot 220. Figs. 10A and 10B show the slot immediately after filling and after 2 hours at room temperature. After 2 hours, the gel balls 222 maintained their integrity and position in the cell while channels formed below and above the gel balls.

[00143] Example 8: In this example, long fibers were employed as the macrostructures. The fibers were PLA fibers measuring 2.5 – 5.1 cm (1 – 2 in.). The carrier fluid was a viscoelastic fluid (ClearFRAC XT) containing 15 mL/L (15 gpt) of a 35-40 wt% surfactant solution and 2.5 mL/L (2.5 gpt) of rheology modifier (such as borate crosslinker) solution, and also containing short (5.6 –

7.1 mm long) PLA fibers at 4.8 g/L (40 ppt) and 0.6 g/mL (5 ppa) of 20/40 mesh sand. The long fibers were added to the carrier fluid at a low concentration of 0.05 g/L. Figure 11 A and B were used to illustrate the expected behavior of this mixture when placed into the fracture. With reference to Fig. 11A, the mixture was injected into a 965.2 mm (38 in.) by 2209.8 mm (87 in.) slot 230 with a 4 mm wide gap to obtain a more or less uniform placement of the mixture. Above the long streaks of proppant free areas 232, there is a tiny (~1 mm) step 234 of the fracture surface. It can be seen that this small disturbance gives rise to a clear hindering line for the proppant clusters 236 to settle onto. Without wishing to be bound by any theory, it is believed that the long fiber in the system may create the same phenomenon.

[00144] While the embodiments have 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 some embodiments have been shown and described and that all changes and modifications that come within the spirit of the embodiments are desired to be protected. It should be understood that while the use of words such as ideally, desirably, 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.

CLAIMS

We claim:

1. A method for treating a subterranean formation penetrated by a wellbore, comprising:
5 injecting a treatment stage fluid, comprising a slurry of a solid particulate freely dispersed in fluid spaces around macrostructures suspended in a carrier fluid, into a fracture in the formation;
aggregating the solid particulate in the fracture to form clusters at
10 respective interfaces with adjacent macrostructures;
reducing pressure in the fracture to prop the fracture open on the clusters
and form interconnected, hydraulically conductive channels
between the clusters.
- 15 2. The method of claim 1, wherein the solid particulate comprises disaggregated proppant and the treatment fluid stage is a proppant-laden hydraulic fracturing fluid.
- 20 3. The method of claim 1, wherein the carrier fluid comprises fiber present in the fluid spaces around the macrostructures to stabilize the treatment stage fluid for the injection into the fracture.
- 25 4. The method of claim 1, further comprising viscosifying the carrier fluid for injection into the formation, and breaking the carrier fluid in the fracture to trigger the aggregation of the solid particulate.
- 30 5. The method of claim 1, further comprising successively alternating concentration modes of the macrostructures in the treatment stage fluid between a relatively macrostructure-rich mode and a macrostructure-lean mode during the treatment stage fluid injection.

6. The method of claim 1, wherein the macrostructures comprise viscous gel.
7. The method of claim 1, wherein the macrostructures comprise viscous gel comprising crosslinked polymer.
- 5 8. The method of claim 1, wherein the macrostructures comprise viscous gel comprising crosslinked polymer selected from polysaccharides, polyacrylates, alginates, polyacrylamides, and combinations thereof.
- 10 9. The method of claim 1, wherein the macrostructures comprise viscous gel reinforced with proppant, subproppant, fiber or a combination thereof.
10. The method of claim 1, further comprising degrading the macrostructures after the aggregation of the solid particulate in the fracture.
- 15 11. The method of claim 1, further comprising elongating the macrostructures in the fracture.
12. The method of claim 1, wherein the macrostructures comprise a gel relatively more viscous than the carrier fluid, and further comprising elongating the macrostructures in the fracture by restraining flow of the macrostructures in the fracture relative to the carrier fluid, by compression of the macrostructures during fracture closure, or by a combination thereof.
- 20 13. The method of claim 1, wherein the macrostructures comprise viscous gel and further comprising compression and elongation of the macrostructures during fracture closure to form gel-filled channels comprising a plurality of the elongated macrostructures in contact with each other.
- 25 30

14. The method of claim 1, wherein the macrostructures in the injection comprise a volume in the treatment fluid from 5 to 30 volume percent [e.g. 15 vol%] and the solid particulate comprises a volume in the treatment fluid from 95 to 70 volume percent [e.g., 85 vol%], based on the total volume of the macrostructures and solid particulate in the treatment fluid.
15. The method of claim 1, wherein the macrostructures have a dimension at least 10 times larger than the solid particulate.
16. The method of claim 1, wherein the macrostructures comprise long fibers having a length of at least about 0.75 cm.
17. The method of claim 1, wherein the macrostructures comprise long fibers having a length of from about 1 cm to about 7.5 cm.
18. The method of claim 1, wherein the injection into the fracture is at a continuous rate of the treatment fluid stage with a continuous concentration of the solid particulate; and further comprising, while maintaining the continuous rate and solid particulate concentration during injection of the treatment fluid stage, successively alternating concentration modes of the macrostructures in the treatment fluid stage between a plurality of relatively macrostructure-rich modes and a plurality of macrostructure-lean modes.
19. The method of claim 1, wherein the injection of the treatment fluid stage forms a homogenous region within the fracture of continuously uniform distribution of the first solid particulate, and wherein the alternation of the concentration modes of the macrostructures forms heterogeneous areas within the fracture comprising macrostructure-rich areas and macrostructure-lean areas.

20. The method of claim 1, further comprising forming bridges with the macrostructures in the fracture to retain the clusters.

5 21. The method of claim 1, wherein the macrostructures are selected from a fiber, a floc, a flake, a ribbon, a platelet, a rod, or a combination thereof.

22. The method of claim 1, wherein the macrostructures are selected from the group consisting of polylactic acid (PLA), polyglycolic acid (PGA),
10 polyethylene terephthalate (PET), polyester, polyamide, polycaprolactam and polylactone, poly(butylene succinate), polydioxanonepolylactic acid, polyester, polycaprolactam, polyamide, polyglycolic acid, polyterephthalate, or a combination thereof.

15 23. The method of claim 1, wherein the macrostructures are long fibers selected from the group consisting of glass, ceramics, carbon (including carbon-based compounds), elements in metallic form, metal alloys, wool, basalt, acrylic, polyethylene, polypropylene, novoloid resin, polyphenylene sulfide, polyvinyl chloride, polyvinylidene chloride, polyurethane, polyvinyl
20 alcohol, polybenzimidazole, polyhydroquinone-diimidazopyridine, poly(p-phenylene-2,6-benzobisoxazole), rayon, cotton, or other natural fibers, cellulose, wool, basalt, glass, rubber, acrylic, mica, and combinations thereof.

25 24. The method of claim 1, wherein the macrostructures comprise sticky fiber.

25. The method of claim 1, wherein the macrostructures are degradable and further comprising degrading the macrostructures after closure of the fracture.

30

26. A system, comprising:
a subterranean formation penetrated by a wellbore;
a treatment slurry stage disposed in the wellbore, the treatment slurry
stage comprising a slurry of a solid particulate freely dispersed in
5 fluid spaces around macrostructures suspended in a carrier fluid;
and
a pump system to inject the treatment fluid stage from the wellbore to the
formation at a pressure above fracturing pressure to inject the
treatment fluid stage into a fracture in the formation.
- 10 27. The system of claim 26, wherein the solid particulate comprises
disaggregated proppant and the treatment fluid stage is a proppant-laden
hydraulic fracturing fluid.
- 15 28. The system of claim 26, wherein the carrier fluid comprises fiber present in
the fluid spaces around the macrostructures to stabilize the treatment
stage fluid for the injection into the fracture.
- 20 29. The system of claim 26, wherein the treatment slurry stage further
comprises a viscosifier in the carrier fluid and a breaker to break the
carrier fluid in the fracture to trigger the aggregation of the solid
particulate.
- 25 30. The system of claim 26, wherein the treatment slurry stage further
comprises successively alternating concentration modes of the
macrostructures in the treatment slurry stage between a relatively
macrostructure-rich mode and a macrostructure-lean mode during the
treatment slurry stage injection.

31. The system of claim 26, wherein the macrostructures comprise viscous gel.
32. The system of claim 26, wherein the macrostructures comprise viscous
5 gel comprising crosslinked polymer.
33. The system of claim 26, wherein the macrostructures comprise viscous gel comprising crosslinked polymer selected from polysaccharides, polyacrylates, alginates, polyacrylamides, and combinations thereof.
- 10 34. The system of claim 26, wherein the macrostructures comprise viscous gel reinforced with proppant, subproppant, fiber or a combination thereof.
35. The system of claim 26, wherein the macrostructures comprise a gel
15 relatively more viscous than the carrier fluid.
36. The system of claim 26, wherein the macrostructures comprise a volume in the treatment slurry stage from 5 to 30 volume percent [e.g. 15 vol%] and the solid particulate comprises a volume in the treatment slurry stage
20 from 95 to 70 volume percent [e.g., 85 vol%], based on the total volume of the macrostructures and solid particulate in the treatment slurry stage.
37. The system of claim 26, wherein the macrostructures have a dimension at
25 least 10 times larger than the solid particulate.
38. The system of claim 26, wherein the macrostructures comprise long fibers having a length of at least about 0.75 cm.
39. The system of claim 26, wherein the macrostructures comprise long fibers
30 having a length of from about 1 cm to about 7.5 cm.

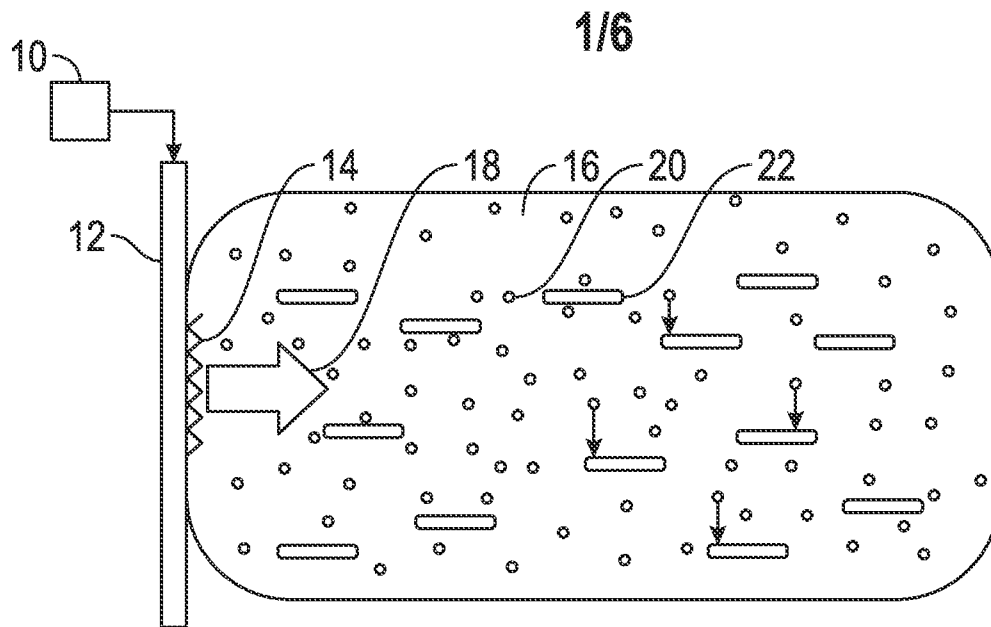


FIG. 1A

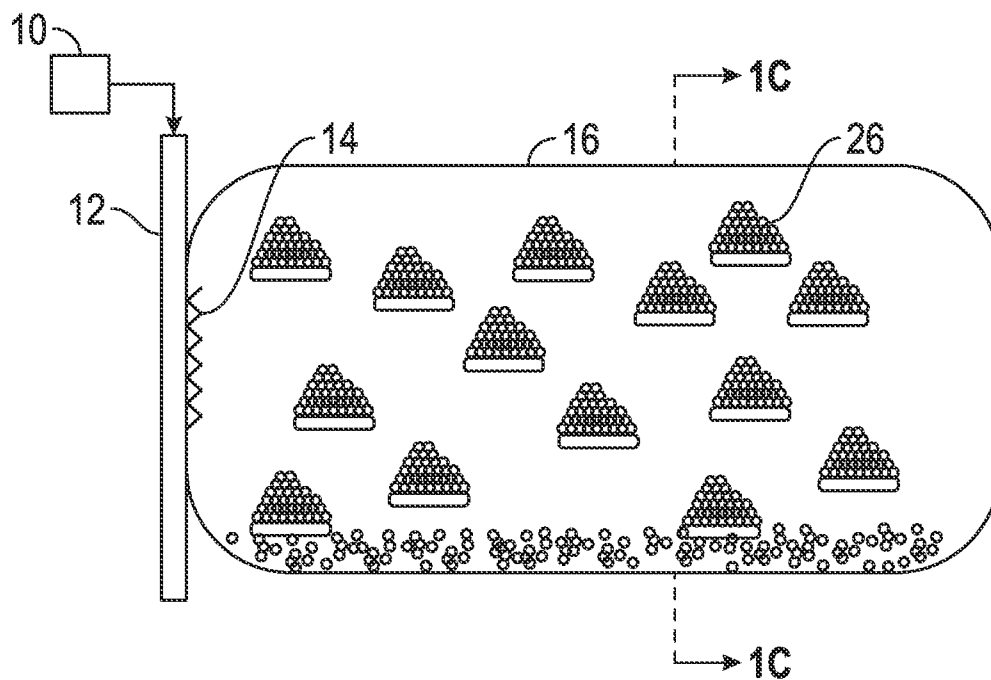


FIG. 1B

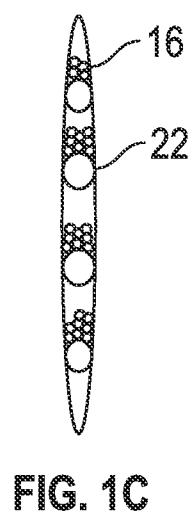


FIG. 1C

2/6

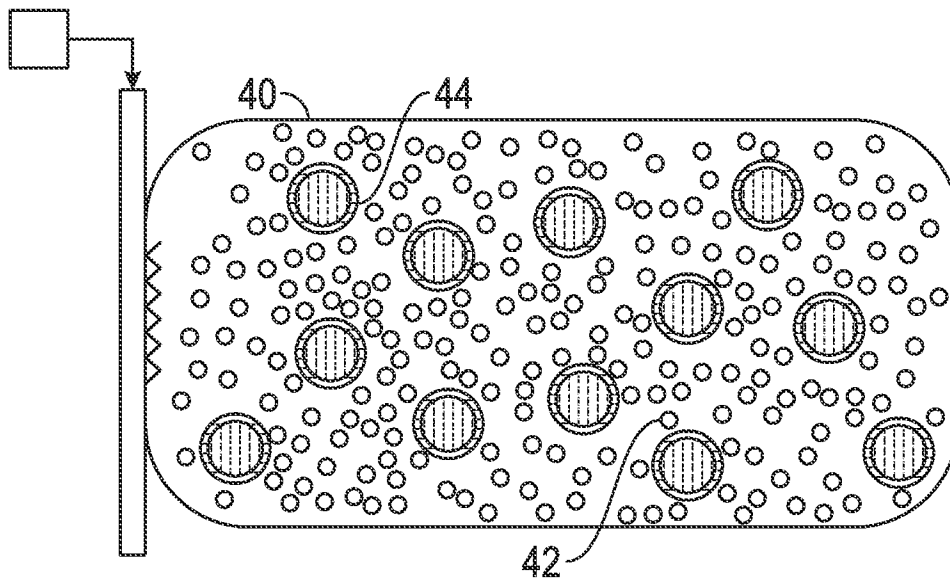


FIG. 2A

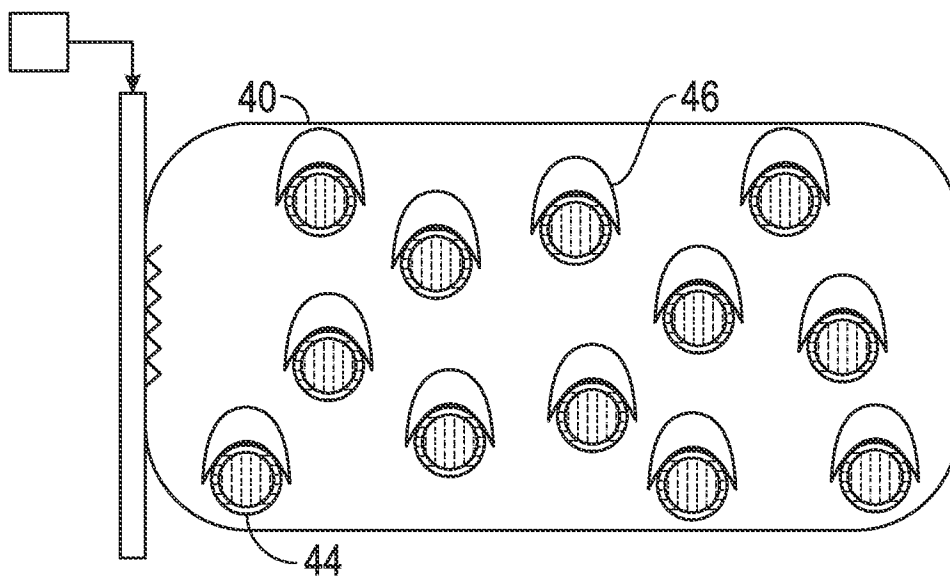


FIG. 2B

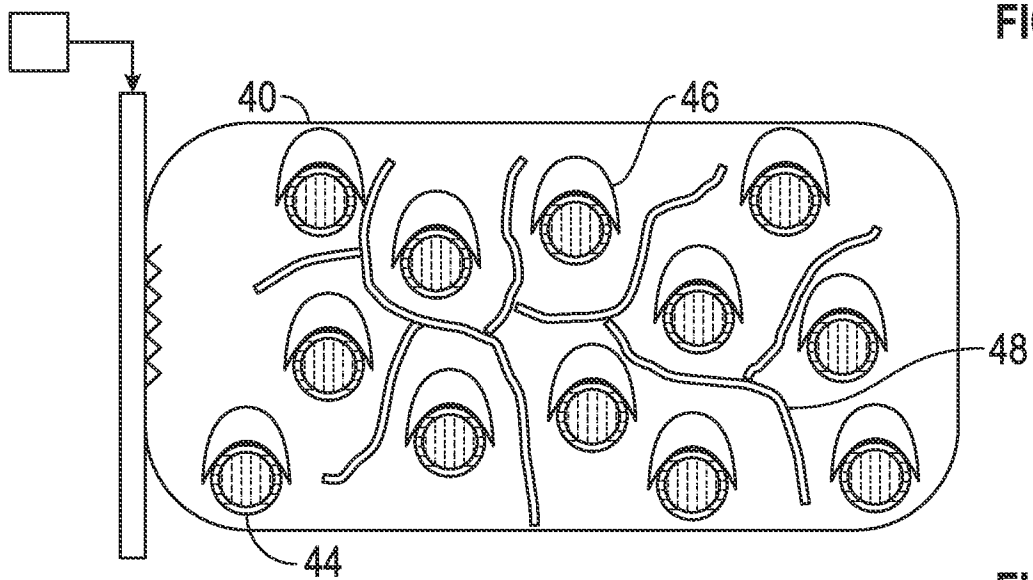


FIG. 2C

3/6

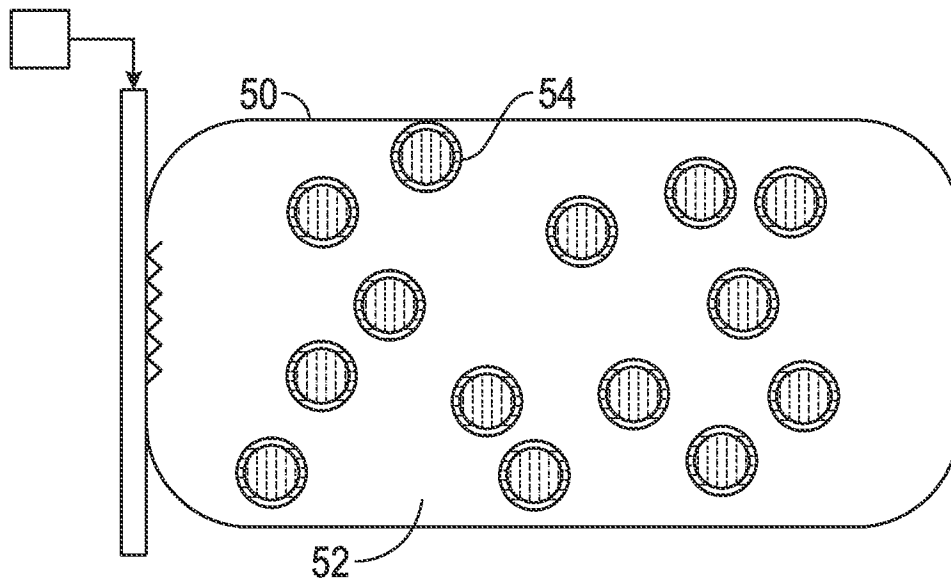


FIG. 3A

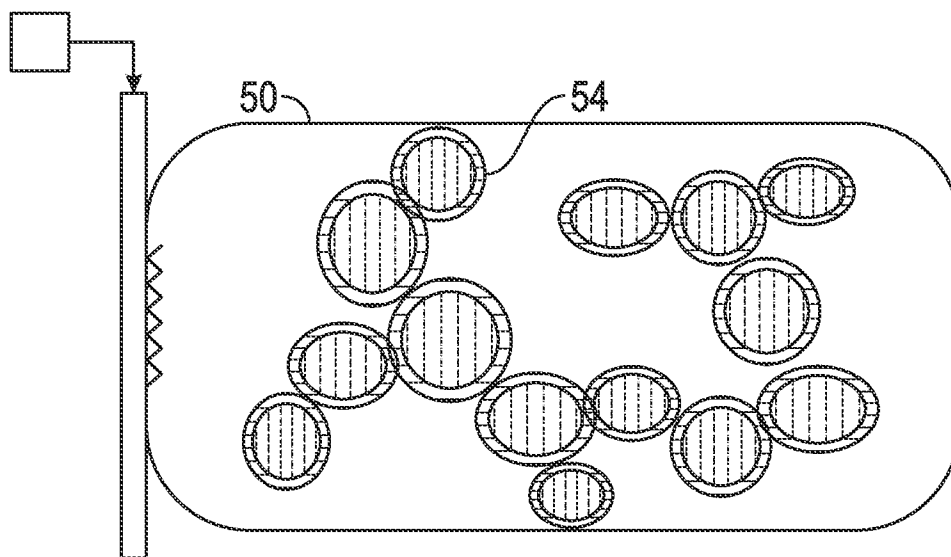


FIG. 3B

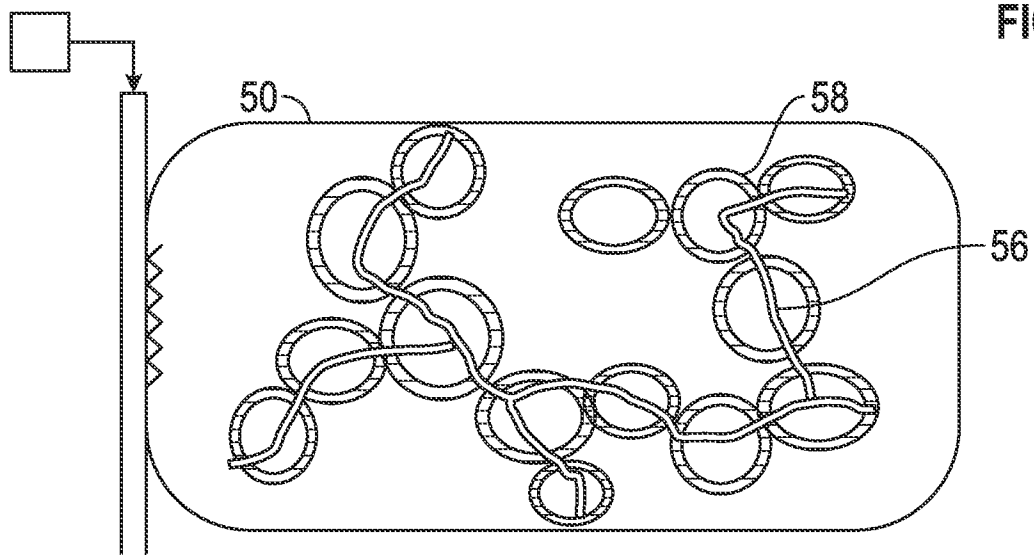


FIG. 3C

4/6

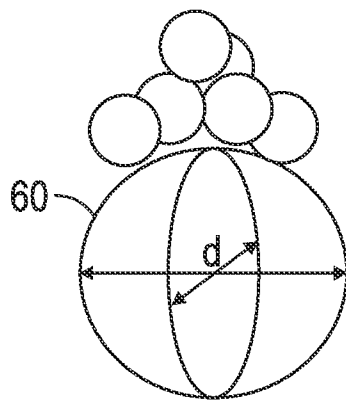


FIG. 4

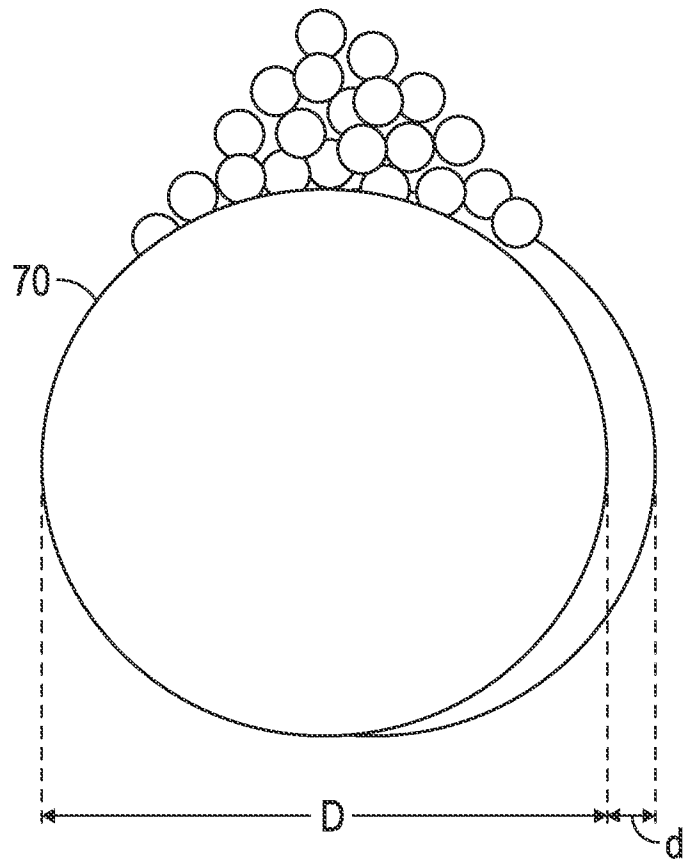


FIG. 5

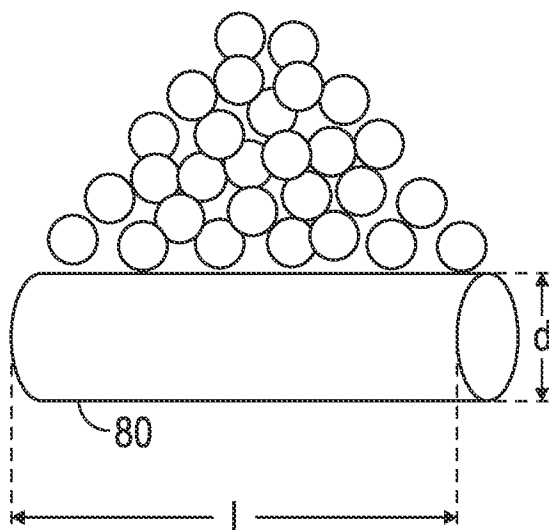


FIG. 6

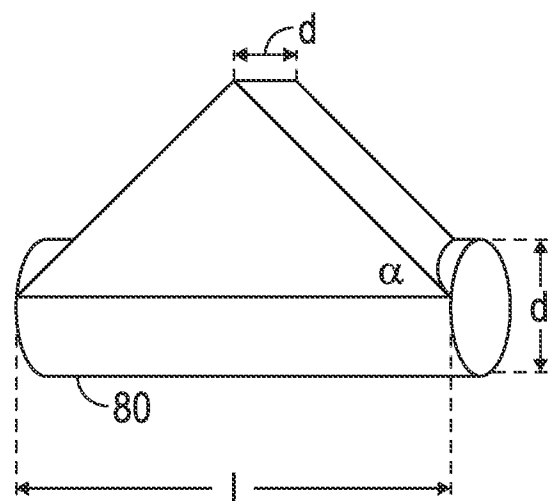


FIG. 7

5/6

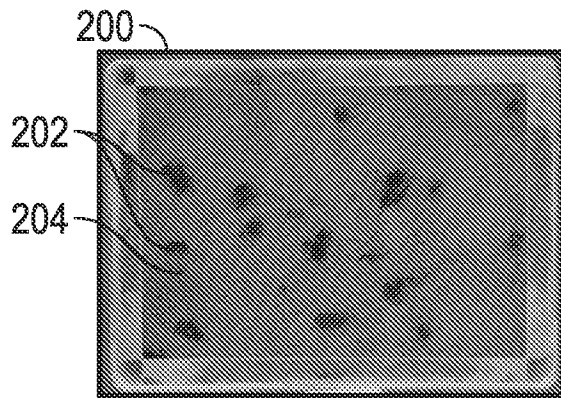


FIG. 8A

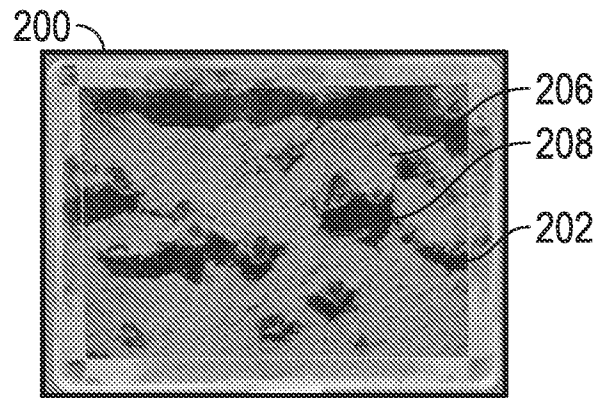


FIG. 8B

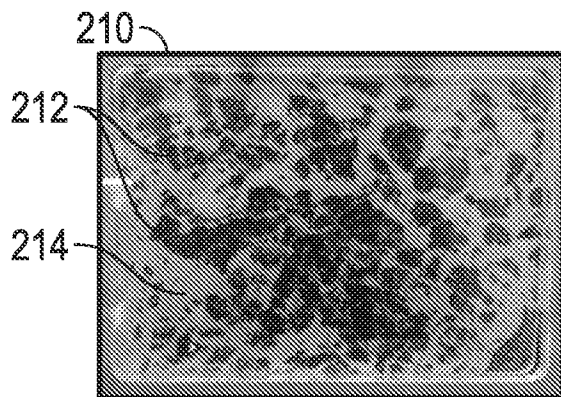


FIG. 9A

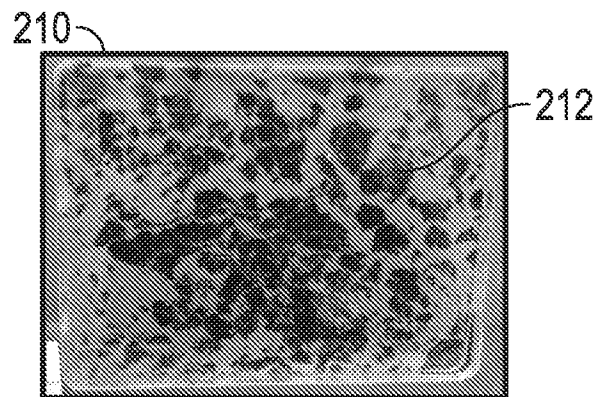


FIG. 9B

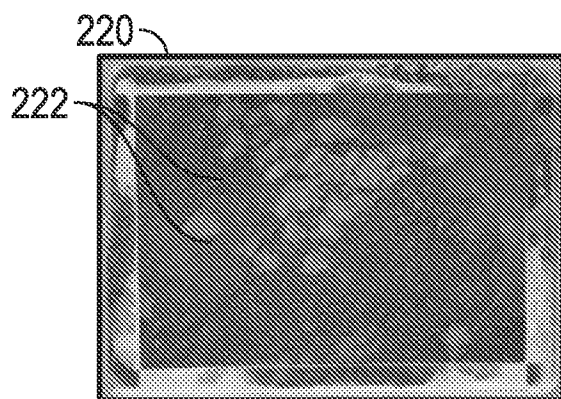


FIG. 10A

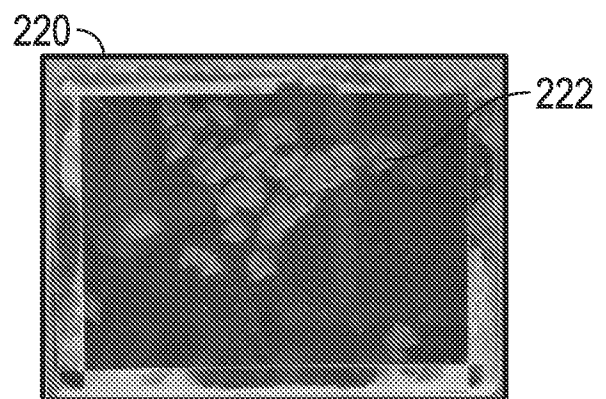


FIG. 10B

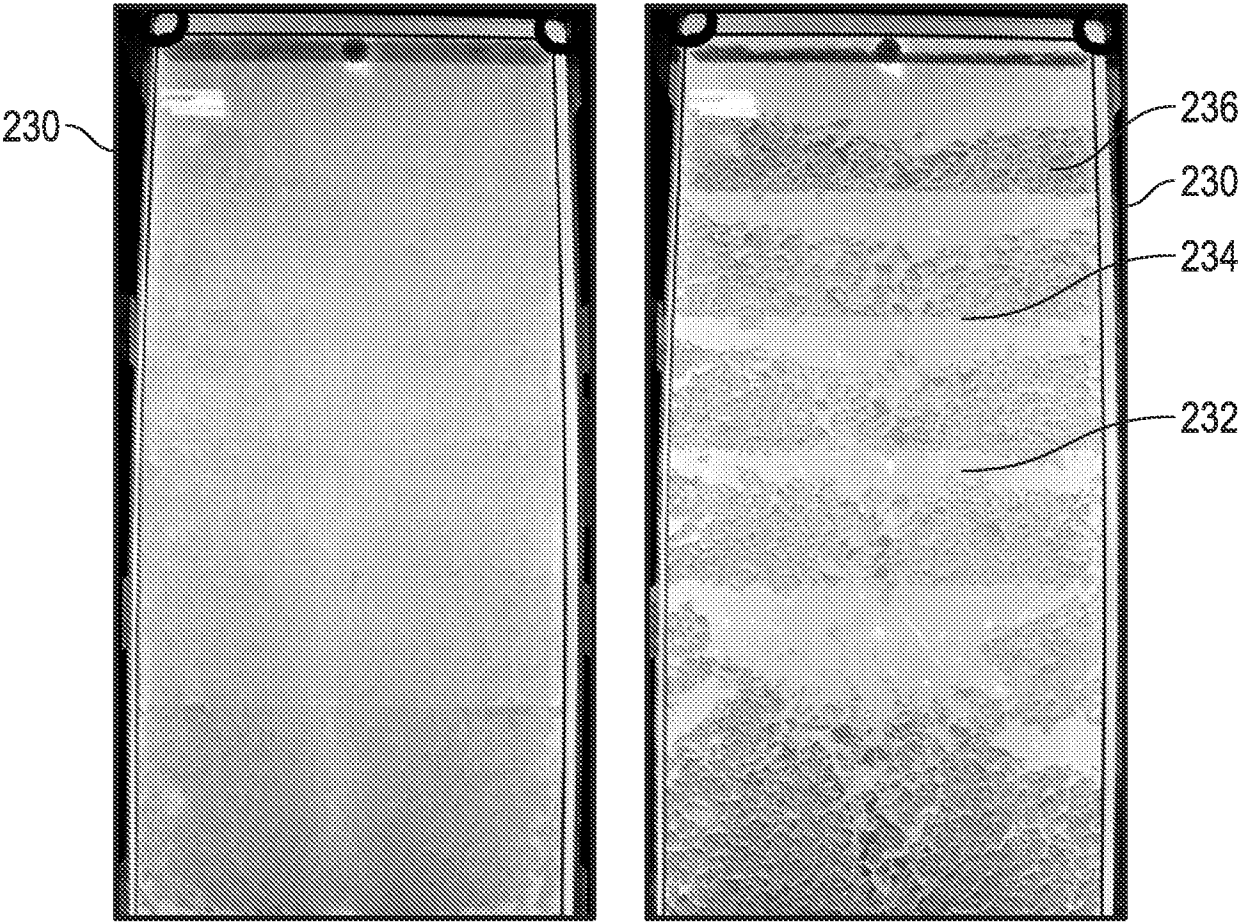


FIG. 11A

FIG. 11B

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2015/020316**A. CLASSIFICATION OF SUBJECT MATTER****E21B 43/26(2006.01)i, C09K 8/62(2006.01)i, C09K 8/80(2006.01)i**

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

E21B 43/26; E21B 43/267; C09K 8/62; C09K 8/80

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Korean utility models and applications for utility models

Japanese utility models and applications for utility models

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

eKOMPASS(KIPO internal) & Keywords: cluster, macrostructure, fiber, gel ball, fluid channel, subterranean formation, proppant, well treatment fluid

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2011-0240293 A1 (LESKO, TIMOTHY et al.) 06 October 2011 See abstract; paragraphs [0011], [0036]–[0075], [0106]; claims 1, 2, 27; and figures 1–4.	26–39
A		1–25
A	US 2012-0305247 A1 (CHEN, YIYAN et al.) 06 December 2012 See paragraph [0007]; claims 1–14, 26; and figures 1–2.	1–39
A	US 2012-0125618 A1 (WILLBERG, DEAN M. et al.) 24 May 2012 See paragraphs [0027]–[0038]; claims 71–86; and figures 2–3.	1–39
A	US 8540024 B2 (KOSAREV, IVAN VITALIEVICH et al.) 24 September 2013 See columns 2–4; claims 1–22; and figures 8A–8D.	1–39
A	US 2004-0256106 A1 (PHILLIPPI, MAX L. et al.) 23 December 2004 See paragraph [0012] and claim 1.	1–39



Further documents are listed in the continuation of Box C.



See patent family annex.

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"&" document member of the same patent family

Date of the actual completion of the international search

13 June 2015 (13.06.2015)

Date of mailing of the international search report

15 June 2015 (15.06.2015)

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INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2015/020316

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