



- (51) International Patent Classification:
E21B 43/26 (2006.01) *C09K 8/62* (2006.01)
E21B 43/247 (2006.01)
- (21) International Application Number:
PCT/US2015/035552
- (22) International Filing Date:
12 June 2015 (12.06.2015)
- (25) Filing Language: English
- (26) Publication Language: English
- (30) Priority Data:
14/313,958 24 June 2014 (24.06.2014) US
- (71) Applicant (for CA only): **SCHLUMBERGER CANADA LIMITED** [CA/CA]; 125 - 9 Avenue SE, Calgary, Alberta T2G 0P6 (CA).
- (71) Applicant (for FR only): **SERVICES PETROLIERS SCHLUMBERGER** [FR/FR]; 42 rue Saint Dominique, 75007 Paris (FR).
- (71) Applicant (for GB, JP, NL only): **SCHLUMBERGER HOLDINGS LIMITED**; P.O. Box 71, Craigmuir Chambers, Road Town, 1110 Tortola, Virgin Islands, British (VG).
- (71) Applicant (for all designated States except AE, AO, BH, CA, CN, FR, GB, GH, IN, JP, LY, MA, MZ, NA, NG, NL, PH, SD, SY, US, VN): **SCHLUMBERGER TECHNOLOGY B.V.** [NL/NL]; Parkstraat 83-89m, NL-2514 JG The Hague (NL).
- (71) Applicant (for AE, AO, BF, BH, BJ, CF, CG, CI, CM, CN, GA, GH, GN, GQ, GW, IN, KM, LY, MA, ML, MR, MZ, NA, NE, NG, PH, SD, SN, SY, TD, TG, VN only): **PRAD RESEARCH AND DEVELOPMENT LIMITED**; P.O. Box 71, Craigmuir Chambers, Road Town, 1110 Tortola, Virgin Island, British (VG).
- (71) Applicant (for US only): **SCHLUMBERGER TECHNOLOGY CORPORATION** [US/US]; 300 Schlumberger Drive, Sugar Land, TX 77478 (US).
- (72) Inventors: **POTAPENKO, Dmitriy**; 15310 Truslow Point Lane, Sugar Land, TX 77478 (US). **BROWN, J., Ernest**;

[Continued on next page]

(54) Title: COMPOUND CLUSTER PLACEMENT IN FRACTURES

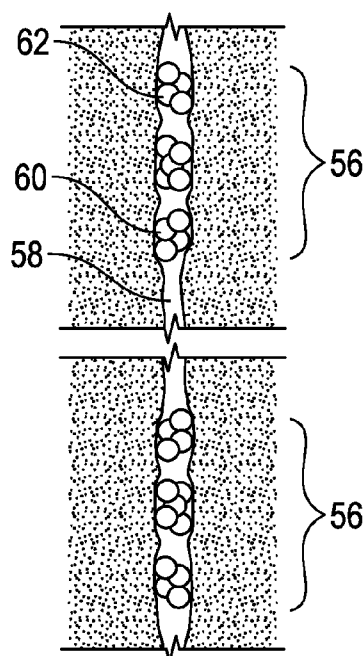


FIG. 8

(57) Abstract: Proppant cluster placement in fractures with foamed carrying fluid. A formation treatment method includes injecting a treatment fluid stage, having a particulate-containing substage containing a self-agglomerating solid composition and a foamed carrying fluid, above a fracturing pressure, and alternating pulses of a pumping parameter to transform the self-agglomerating composition into a channelized solids pack, and closing the fracture. Also disclosed are methods of modeling a fracture treatment interval for such a method, and methods of treatment and systems to treat with such a treatment fluid stage, wherein solid particulate-rich substages are larger than the solid particulate-lean substages to form particulate-rich island regions, an interconnected network of open channel regions between the island regions and the island regions are channelized to form particulate clusters within the island regions separated from adjacent particulate clusters by open voids in the island regions.



7246 Welshwood Ln., Sugar Land, TX 77479 (US).
LAFFERTY, Theodore; 1322 Shady Bend Drive, Sugar
Land, TX 77479 (US). **MILLER, Matthew, J.**; 23607
Rollinford Lane, Katy, TX 77494 (US).

(74) **Agents:** **VANDERMOLEN, Mathieu** et al.; 10001 Rich-
mond Avenue, IP Administration Center of Excellence,
Room 4720, Houston, TX 77042 (US).

(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))

COMPOUND CLUSTER PLACEMENT IN FRACTURES

RELATED APPLICATION DATA

[0001] None.

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 increase permeability of subterranean formations. A fracturing fluid is injected into the wellbore passing through the subterranean formation. A propping agent (proppant) is injected into the fracture to maintain the distance between the fracture walls upon closure and, thereby, to provide hydraulic conductivity and improved extraction of extractive fluids, such as oil, gas or water.

[0004] Heterogeneous placement of the proppant in clusters can create conductive channels around the proppant clusters. The improper placement of proppant particles before fracture closure, however, can pose a risk of screenout in the wellbore or decrease the conductivity in the fracture. For example, if the channels are too wide and/or the proppant clusters of insufficient strength, the fracture may collapse or the fracture width may be narrower than needed for good conductivity; or if too much proppant is used the channels may be too narrow and/or insufficiently interconnected for good conductivity.

SUMMARY

[0005] The disclosed subject matter of the application in some embodiments provides methods and systems to treat subterranean formations penetrated by a wellbore using a compound cluster placement technique.

[0006] In some embodiments according to the present disclosure, a method to treat a subterranean formation penetrated by a wellbore comprises providing a treatment fluid stage comprising a particulate-containing substage comprising a self-agglomerating solid composition and a foamed carrying fluid; injecting the treatment fluid stage above

a fracturing pressure to place the treatment fluid stage in a fracture in the formation according to pumping parameters selected from composition of the particulate-containing substage and pumping rate of the treatment fluid stage; alternating pulses of at least one of the pumping parameters to transform the self-agglomerating solid composition in the fracture into a channelized solids pack comprising clusters having a high concentration of solids, wherein the clusters are separated by open voids having a substantially reduced concentration of solids between the clusters; and closing the fracture onto the clusters.

[0007] In some embodiments, the self-agglomerating solids composition comprises fiber. In some embodiments, the transformation of the solid composition comprises destabilization of the foamed carrying fluid. In some embodiments, the at least one alternated pumping parameter comprises foam quality of the carrying fluid between alternate pulses within the particulate-containing substage, such as, for example, wherein the foam quality (volume percent gas) is alternated between values different by at least 5 percent, e.g., 60% foam quality pulses alternated with 0% foam quality (liquid carrying fluid only), e.g., where the composition of one or more of solids and/or other components in the liquid phase remains constant or continuous with respect to the liquid phase.

[0008] In some embodiments, the at least one alternated pumping parameter comprises a concentration between alternate pulses within the particulate-containing substage of a fluid rheology component [defined as anything that changes fluid rheology, such as, for example, a viscosifier, breaker, crosslinker, decrosslinker, etc. before closing the fracture, such as, for example, a concentration of breaker between alternate pulses, e.g., wherein the breaker reduces the viscosity of the carrying fluid before closing the fracture. In some embodiments, the at least one alternated pumping parameter is selected from the group consisting of crosslinker concentration, crosslinker delay agent concentration, decrosslinker concentration, fiber concentration, proppant concentration, fluid loss additive concentration, clay stabilizer concentration, pH adjusting agent concentration, and combinations thereof.

[0009] In some embodiments, closing the fracture comprises shutting in the wellbore and waiting for the fracture to close, or forced fracture closure.

[0010] In some embodiments, the treatment fluid stage comprises alternating a plurality of the solid particulate-containing substages with solid particulate-lean substages, wherein a volume of each of the solid particulate-containing substages is larger than a respective volume of an adjacent one of the particulate-lean substages (e.g., the laden stage is larger than the smaller of the immediately preceding or following clean stages to take leading/trailing laden stages and ignore size of pad/flush stages).

[0011] In some embodiments according to the present disclosure, a method to treat a subterranean formation penetrated by a wellbore comprises considering [defined as estimating or measuring] closure stress and stiffness of an interval of the formation; modeling the interval based on the closure stress and stiffness of the interval to determine a minimum coverage of propped regions in a fracture in the interval and maximum channel breadth between the propped regions to inhibit collapse of the channels; formulating a treatment fluid stage comprising alternating solid particulate-rich and solid particulate-lean substages, wherein at least a portion of the particulate-rich substage comprises a self-agglomerating solid composition and a foamed carrying fluid, wherein a volume of each of the particulate-rich substages is larger than a respective volume of an adjacent one of the particulate-lean substages; injecting the formulated treatment fluid stage above a fracturing pressure into the formation by alternately injecting the solid particulate-rich and solid particulate-lean substages into the fracture; forming a plurality of particulate-rich island regions in the fracture to provide at least the minimum coverage of propped regions as determined by the modeling; forming an interconnected network of open channel regions between the island regions in the fracture having a channel breadth less than the maximum channel breadth as determined by the modeling; reducing pressure in the fracture to close the fracture propped on the island regions; and hydraulically conducting fluid flow through the open channel regions between the formation and the wellbore, e.g., producing reservoir fluids or injecting a fluid into the reservoir.

[0012] In some embodiments, the method may further comprise channelizing the solid particulate rich island regions in situ in the fracture to form solid particulate clusters within the island regions separated from adjacent solid particulate clusters by open voids within the island regions. In some embodiments, the solid particulate-rich substages and the solid particulate-lean substages in the treatment stage fluid may have an overall volumetric ratio from 60:40 to 95:5, or from 70:30 to 90:10.

[0013] In some embodiments according to the present disclosure, a method comprises injecting a treatment fluid stage above a fracturing pressure into the formation to distribute a mixture of a solid particulate in a fracture; alternately injecting solid particulate-rich and solid particulate-lean substages of the treatment fluid stage into the fracture, wherein at least a portion of the particulate-rich substage comprises a self-agglomerating solid composition and a foamed carrying fluid, wherein a volume of each of the solid particulate-rich substages is [at least 50%] larger than a respective volume of an adjacent one [immediately preceding or following] of the solid particulate-lean substages to form a plurality of solid particulate-rich island regions in the fracture and an interconnected network of open channel regions between the island regions; channelizing the particulate-rich island regions in situ in the fracture to form particulate clusters within the island regions separated from adjacent particulate clusters by open voids in the island regions; reducing pressure in the fracture to close the fracture onto the island regions; and hydraulically conducting fluid flow through the open channel regions between the formation and the wellbore, e.g., producing reservoir fluids or injecting a fluid into the reservoir..

[0014] In some embodiments, the solid particulate-rich substages each comprise alternating pulses injected at different rates. In some embodiments, the solid particulate-rich substages may each comprise alternating pulses comprising a substantially uniform distribution of one or more components in the alternate pulses and a heterogeneous distribution between alternate pulses of at least one other component, e.g., another component selected from the foam quality (gas), solid particulate, fibers, anchorant, agglomerant, agglomerant aid, agglomerant aid activator, binding liquid, an induced settling trigger, viscous gel macrostructures, and combinations thereof.

[0015] In some embodiments, the particulate-rich substages each comprise alternating pulses comprising a substantially uniform distribution of one or more components with respect to a liquid phase of the carrying fluid in the alternate pulses, and a heterogeneous distribution between alternate pulses of foam quality (volume percent gas), wherein the foam quality is alternated between values different by at least 5 percent.

[0016] In some embodiments, the carrying fluid comprises a viscoelastic surfactant. In some embodiments, the treatment fluid stage comprises a pH control agent. In some embodiments, the treatment fluid stage comprises an ester and the method further comprises releasing an acid from the ester. In some embodiments, the solid particulate-lean substages comprise fiber. In some embodiments, the solid particulate-rich substages comprise a slurry of the solid particulate freely dispersed in fluid spaces around macrostructures suspended in a carrying fluid.

[0017] In some embodiments, the solid particulate-rich substages and the solid particulate-lean substages in the treatment stage fluid have an overall volumetric ratio from 60:40 to 95:5, or from 70:30 to 90:10. In some embodiments, the solid particulate-rich substages provide at least a minimum coverage of propped regions comprising the islands and a channel breadth between the propped regions sufficiently small to inhibit collapse of the open channel regions in the interconnected network, e.g., a propped region:open channel region areal ratio from 60:40 to 95:5, or from 70:30 to 90:10.

[0018] In some embodiments according to the present disclosure, a system to treat a fracture interval of a formation penetrated by a wellbore comprises: a subterranean formation penetrated by a wellbore; a treatment fluid stage disposed at least partially in the wellbore, the treatment fluid stage comprising solid particulate-rich and solid particulate-lean substages, wherein a volume of each of the solid particulate-rich substages is larger (representing more than 50% of the total volume) than a respective volume of an adjacent one (immediately preceding or following) of the solid particulate-lean substages to form a plurality of solid particulate-rich island regions in the fracture and an interconnected network of open channel regions between the island regions; the solid particulate-rich substages each comprising alternating pulses comprising a

substantially uniform distribution of one or more components with respect to a liquid phase of a carrying fluid in the alternate pulses, and a heterogeneous foam quality to channelize the particulate-rich island regions in situ in the fracture to form particulate clusters within the island regions separated from adjacent particulate clusters by open voids within the island regions; and a shut in system to close the fracture onto the solid particulate-rich island regions.

[0019] This summary is provided to introduce a selection of concepts that are further described below in the detailed description. This summary is not intended to identify key or essential features of the claimed subject matter, nor is it intended to be used as an aid in limiting the scope of the claimed subject matter.

BRIEF DESCRIPTION OF THE DRAWINGS

[0020] 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.

[0021] Fig. 1 schematically illustrates proppant distribution in a fracture upon placement according to embodiments of the present disclosure.

[0022] Fig. 2 schematically illustrates proppant distribution in the fracture of Fig. 1 following heterogeneous settling according to embodiments of the present disclosure.

[0023] Fig. 3 schematically illustrates a propped fracture having proppant clusters separated by open voids within a propped region of the fracture according to embodiments of the present disclosure.

[0024] Fig. 4 illustrates a pumping sequence of a proppant-laden substage with alternated foam quality according to embodiments of the present disclosure.

[0025] Fig. 5 schematically illustrates a fracture filled with alternating stages of homogenous proppant-rich and proppant-lean treatment fluids.

[0026] Fig. 6 schematically illustrates a fracture filled with alternating stages of in situ channelizing proppant-rich treatment fluid and proppant-lean treatment fluid, wherein

the volume of the proppant rich treatment fluid is greater than that of the proppant lean treatment fluid, according to embodiments of the present disclosure.

[0027] Fig. 7 schematically illustrates a fracture filled with alternating stages of in situ channelizing proppant-rich treatment fluid and proppant-lean treatment fluid, wherein the volume of the proppant rich treatment fluid is substantially greater than that of the proppant lean treatment fluid, according to further embodiments of the present disclosure.

[0028] Fig. 8 is a sectional view of a portion of the propped fracture of Fig. 7 as seen along the view lines 8-8.

DETAILED DESCRIPTION OF SOME ILLUSTRATIVE EMBODIMENTS

[0029] 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.

[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) 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 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 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 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 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] 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 between particulate clusters in a fracture after at least a portion of the fracture has been filled with a generally continuous proppant or other particle concentration or regions of continuous proppant concentration. The following discussion refers to proppant as one example of the first solid particle which may be used in the present disclosure, although other types of solid particles are contemplated. The terms proppant and sand are used interchangeably herein.

[0035] The term “self-agglomerating solid composition” refers to an in situ treatment fluid system wherein a generally uniform region or island of solids placed into a formation automatically coalesces into proppant clusters within the region or island separated by open voids between the clusters within the region nor island.

[0036] The term “foamed carrying fluid” is used interchangeably with “energized fluid” and “foam” to 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 terms "foamed carrying fluid" and "energized fluid" encompass both energized fluids and foams and refer to any stable mixture of gas and liquid, regardless of the foam quality. Foamed carrying 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. 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.

[0037] As used herein, "destabilization" of a foamed fluid refers to the formation of large gas bubbles, e.g., the coalescence of fine gas bubbles into larger bubbles, which are incapable of supporting any solid particles which may be present, resulting in the formation of solid particle clusters adjacent to the bubbles. In some embodiments, the foam quality can be used as a parameter to adjust the destabilization rate of the treatment fluid, e.g., higher foam quality may lead to more destabilization and larger proppant clusters, and/or alternating pulses of different foam quality, e.g., pulses of 80% foam quality alternated with 75% foam quality pulses, or 70% and 40%, or 50% and 0%, or the like, where the liquid carrier fluid phase has an otherwise continuous composition and proppant loading, may enable different proppant settling rates between the adjacent pulses and a heterogeneous proppant distribution, and thus a heterogeneous conductivity distribution.

[0038]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, or channels filled with proppant islands of proppant clusters wherein the proppant clusters are spaced apart by open voids between the proppant clusters, such that the channel has a relatively higher conductivity than adjacent non-channel areas.

[0039]As used herein, “compound cluster placement” refers to a fracture system comprising proppant islands spaced apart by open channels wherein the proppant islands are each comprised of a plurality of proppant clusters, each proppant cluster comprising a plurality of proppant particles in contact with adjacent particles, wherein the spacing between the proppant clusters within a proppant island is much less than the spacing between adjacent proppant islands, e.g., an order of magnitude less. Proppant clusters may or may not be porous, e.g., they may have a packed volume fraction from 50 to 100% with interstitial flow paths on the order of the largest particle size, whereas proppant islands in a compound cluster placement system may each comprise a plurality of clusters with intermediate sized flow channels or voids between the clusters, which are generally smaller than the relatively larger open flow channels between the islands.

[0040]Proppant coverage refers to the area of a fracture along its extent which contains the proppant islands or other propped regions in relation to the total area of the extent of the fracture. Because of the close proximity of the clusters within the islands relative to the stiffness and closure stress, the entire area of the island may be considered to be propped. The “channel breadth” refers to the distance between the propped regions. Modeling tools such as FracCADE (available from Schlumberger) or MATLAB are available to determine, based on the closure stress, e.g., the overburden pressure, and the stiffness or rigidity of the formation at the fracture face, the maximum channel breadth that can be tolerated before the fracture will collapse and opposing faces of the fracture between the adjacent islands will be closed off. In some embodiments, the treatment is designed to avoid collapse of the channels, or to minimize risk of collapse, by providing open channels between the proppant islands which generally do not

exceed the maximum allowable open channel breadth for the particular fracture closure stress and stiffness.

[0041] 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.

[0042] Conversely, a parameter as a function of another variable such as time or rate, 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.

[0043] In embodiments, the open voids between the clusters within the proppant fill or proppant islands may be formed in situ after placement of the proppant and/or proppant islands in the fracture by differential movement of the proppant particles, e.g., by foam destabilization, by coalescence of a binding liquid around the agglomerant and/or proppant particles, 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. In embodiments, the movement of the proppant particles may be facilitated by the presence or introduction of an agglomerant aid such as a binding liquid, e.g., a hydrophobic liquid. In embodiments; and the movement of the proppant particles may optionally be further facilitated by reduction of the viscosity of the treatment fluid, which may be instantaneous, gradual, or stagewise.

[0044] According to some embodiments herein, the open voids between the clusters within the proppant islands or other regions of proppant fill may be formed by 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 the fracture and aggregating the solid particulate in the fracture to form clusters at respective interfaces with adjacent macrostructures. According to some embodiments, the solid particulate comprises disaggregated proppant in a proppant-laden substage or pulse within the substage. According to some embodiments, the carrier fluid comprises fiber present in the fluid spaces around the macrostructures, e.g., gel balls, to stabilize the treatment stage fluid for the injection into the fracture.

[0045] In some embodiments, the method comprises pumping a proppant laden fracturing fluid comprising a foamed carrying fluid into a subterranean formation at pressure above a fracturing pressure of the formation. With reference to the system illustrated in Fig. 1, a pumping system 10 supplies a treatment fluid 12 to wellbore 14 and into the fracture 16. In this example, the treatment fluid 12 comprises a foamed proppant slurry, which initially fills the fracture 16 with a generally homogenous distribution of a propping agent. In some embodiments, the proppant slurry is destabilized, for example, prior to closure of the fracture 16, as illustrated in Fig. 2, resulting in the formation of proppant-rich clusters 18 separated by proppant-lean or proppant-free void spaces 20 between the clusters. Where the fracturing fluid 12 comprises macrostructures 22 such as fibers, these may dispose in the clusters 18, the void spaces 20, or a combination thereof. As illustrated in Fig. 3, upon closure of the fracture 16 and removal of any fibers, e.g., by hydrolysis or other degradative pathway, the clusters 18 prop open the fracture and fluid may readily flow through the conductive void spaces 20.

[0046]As seen in Fig. 4, a pumping sequence used in some embodiments has a continuous pumping rate 30, a continuous proppant concentration 32 (with respect to the liquid carrier phase) and a discontinuous foam quality 34, 36. In these embodiments, the proppant loading may follow a proppant-free pad stage 38 beginning at a relatively low proppant loading 40 which after one or more foamed pulses 34A, may have a smooth ramp 42 up over a series of foamed pulses 34B to a higher proppant loading 44, and then be maintained at a constant rate 44 for an additional series of foamed pulses 34C until the proppant stage 32 is ended, and followed by a flush stage 46.

[0047]Alternatively, the pumping sequence used in some embodiments may have a continuous pumping rate, a continuous proppant concentration (with respect to the liquid carrier phase) and a discontinuous rate for a gel breaking agent.

[0048]With reference to the system illustrated in Fig. 5, a pumping system 10 supplies a treatment fluid 12 comprising a foamed carrying fluid to wellbore 14 in communication with a fracture 16. In this system the treatment fluid stage comprises alternating proppant-laden substages 48, which may contain a foamed carrying fluid, with a proppant-lean substage 50, which may or may not comprise foamed carrying fluid, which form proppant islands 52 in the fracture 16 corresponding to the proppant-laden substages 48 and channels 54 between the islands corresponding to the proppant-lean substages 50.

[0049]During the injection of the fracturing fluid, the pressure in the well or treatment zone thereof may be sufficiently maintained to keep the fracture 16 from closing before the islands 52 and channels 54 are formed, following which the fracture is closed on the proppant islands 52, which theoretically maintain the spacing between the opposing fracture faces for hydraulic conductivity. In this system, the channels 54 may be relatively wide since the fracture 16 may have a high rigidity such that fracture collapse does not occur, and thus a relatively high total volume of the proppant-lean substages 50 may be employed relative to that of the proppant-laden substages 52.

[0050]It should be noted when considering the relative volumes or other properties of the proppant-laden substages 48 relative to the proppant-lean substages 50, one

generally refers only to the main substages, that is, any preceding pad or pre-pad stages as well as any following flush stages are not generally considered as being either a proppant-laden substage 48 or a proppant-lean substage 50 and may be excluded from the calculation. For example, the initial proppant-laden substage 48 is considered relative to the initial trailing proppant-lean substage 50, whereas the ultimate proppant-laden substage 48 may be considered relative to the immediately preceding proppant-lean substage 50, and the intermediate proppant-laden substages 48 may be considered relative to either the immediately preceding or immediately following proppant-lean substage 50.

[0051] In some embodiments according to the present disclosure as seen in Fig. 6, the volume of the proppant-laden substages 48 is as large as or larger than that of the adjacent proppant-lean substages 50, which may result in a proportionately larger proppant coverage by the proppant islands 56 in the fracture 16. The open channels 58 between the islands 56 in some embodiments do not exceed the maximum allowable channel breadth to inhibit collapse of the fracture, while at the same time providing improved fracture propping capability, e.g., a relatively wider fracture, due to the higher propped region coverage, depending on the closure stress and strength of the fracture rock. That is to say, the open channels 54 may have a narrow breadth relative to Fig. 5, but may also have a greater width to maintain equivalent or improved conductivity, in some embodiments.

[0052] In addition, in some embodiments the islands 56 in Fig. 6 may be comprised of a plurality of proppant clusters 60 and open voids 62 to provide additional hydraulic conductivity through the islands 56. In some embodiments, these proppant clusters may be formed within the islands 56 by employing proppant-laden substages 48 which have an in-situ channelization functionality, e.g., a pulsed foamed quality, pump rate or concentration of proppant or other component such that clusters 60 of the proppant are formed within the islands 56. For example, the proppant-laden substages 48 placed in the fracture 16 may include, activate, generate or release a trigger that induces channelization; may be pulsed at different rates to induce clustering of the proppant within the islands 56; may contain alternating pulses comprising a substantially uniform distribution of one or more components in the alternate pulses and a heterogeneous

distribution between alternate pulses of at least one other component, e.g., another component selected from the foam quality, solid particulate, fibers, breaking agent, delayed viscosity reducing agent, anchorant, agglomerant, agglomerant aid, agglomerant aid activator, binding liquid, an induced settling trigger, viscous gel macrostructures, and combinations thereof; or the like.

[0053] For some embodiments represented by Figs. 7 and 8, the volume of the proppant-laden substages 48 is substantially larger than that of the adjacent proppant-lean substages 50, which results in a substantially larger proppant coverage by the proppant islands 56 in the fracture 16. For example, solid particulate-rich substages 48 and the solid particulate-lean substages 50 may have an overall volumetric ratio from 60:40 to 95:5, or from 70:30 to 90:10, or the like, e.g., 80:20. Or, the relative volumes of the proppant-laden substages 48 and proppant-lean substages 50 may be such that the ratio of the proppant coverage (area of the islands 56) to that of the channels 58 is from 60:40 to 95:5, or from 70:30 to 90:10, or the like, e.g., 80:20.

[0054] In some embodiments, the movement of proppant into clusters 60 may be facilitated by the presence of the foamed carrying fluid in the treatment fluid 12, especially in the proppant-laden substages 48 and/or the proppant-lean substages 50, or by activation of an optional trigger to destabilize the proppant-laden substages 48 of the fracturing fluid and/or the regions of the proppant islands 56, such as, for example, a breaker or decrosslinking additive to at least partially reduce the localized viscosity of the fracturing fluid, e.g., from a viscosity corresponding to a crosslinked polymer to that of a linear polymer. Agglomerants such as fibers may optionally also settle in the fracture, e.g., at a slower rate than the proppant, which may result in some embodiments from the agglomerants having a specific gravity that is equal to or closer to that of the carrier fluid than that of the proppant. As one non-limiting example, the proppant may be sand with a specific gravity of 2.65, the agglomerants may be a localized fiber-laden region comprising fiber with a specific gravity of 1.1-1.5, e.g., polylactic acid fibers having a specific gravity of 1.25, and the carrier fluid may be aqueous with a specific gravity of 1-1.1.

[0055] In some embodiments settling of the proppant may also be mediated by buoyancy imparted by gas, a binding liquid and/or fibers, which may have a specific gravity lower than that of the proppant, carrier liquid or other component. In this example, the lower specific gravity component may have a lower settling rate relative to the proppant. In other embodiments, agglomerants and/or anchorants may interact with either or both of the fracture faces, e.g. by friction or adhesion, which may similarly be mediated by the presence of any binding liquid in some embodiments, e.g., where the binding liquid has an affinity for the formation surface, and may have a density similar or dissimilar to that of the proppant, e.g., glass fibers may have a specific gravity greater than 2.

[0056] As a result of coalescence of proppant induced by differential settling rates in the carrying fluid according to some embodiments, the proppant may form clusters adjacent respective agglomerants, facilitated by the presence of any binding liquid, and settling is retarded. Further, in some embodiments, the agglomerants may be anchorants which are activated to form immobilized anchoring structures, which may be mediated by any binding liquid, to hold the clusters fast against the opposing surface(s) of the fracture.

[0057] In some embodiments, the method decreases the viscosity in the proppant-laden substages 48 of the fracturing fluid and/or the regions of the proppant islands 56 by employing a fracturing fluid comprising a crosslinked polymeric viscosifier for proppant placement, in one temporal stage to that of a linear gel, to promote proppant/agglomerant/binding liquid agglomeration for in-situ channelization, but without completely breaking the viscosity to facilitate anchoring prior to fracture closure, i.e., the formation or activation of anchors to inhibit complete settling of the proppant system to the floor of the fracture or proppant island.

[0058] The in-situ channelization concept is based on the creation of clusters, which in some embodiments may be anchored in the fracture within the proppant islands, to promote open voids within the islands. Anchors are materials designed to stay in place in the fracture, while clusters are the agglomeration of sand and any fiber, binding liquid or other materials that settle on top of the anchors after placement but before fracture closure. To initiate settling of the sand within the islands, a decrease in the fluid

viscosity is implemented in some embodiments. In some embodiments, an acid or acid precursor may function as a de-crosslinker which may be mixed homogeneously in the treatment fluid or the proppant-laden substages 48 thereof at the surface, or pulsed into the proppant-laden substages 48, and pumped down the wellbore and into the fracture. After placement, the de-crosslinker, which in some embodiments may be based on ester chemistry to release the acid by hydrolysis, is allowed to react with the crosslinked polymer to reduce its viscosity. After fracture closure, a breaker such as an oxidative breaker may break and/or, in the case of a partially broken or decrosslinked viscosifier, continue to more fully break the viscosifier to facilitate cleanup and reservoir production.

[0059] In-situ channelization in some embodiments promotes high conductivity through proppant islands 56 by the formation of open void spaces 32, relying on the settlement of the proppant and fibers on the anchors to form clusters, leaving high conductive void spaces 32 within the proppant islands 56 that are free of proppant surrounding the clusters 60. The rate of settlement of the proppant is related to the creation of clusters 60, where a high settling rate may lead to no anchors or clusters, whereas a slow settling rate can lead to no open voids 62 due to premature fracture closure. The settlement of the sand depends on the viscosity and specific gravity of the fluid, and also, according to embodiments herein, on the rate at which this viscosity decreases at the reservoir temperature.

[0060] In one representative example according to some embodiments, a gelling agent is guar based, crosslinked with borate or with a delayed crosslinker and the oil-in-water emulsion employs alkaline emulsifiers for stability, which may be destabilized by reducing the pH. In some embodiments, the crosslinkers are used to create highly viscous gels comprising a stable oil-in-water emulsion at a pH between 8 and 12. In some embodiments, esters are used as dual functionality demulsifiers and decrosslinkers, since at high reservoir temperatures some esters can undergo hydrolysis and form carboxylic acids, lowering the pH of the fluid and thus destabilizing the emulsion to release the oil phase while simultaneously deactivating the borate or other crosslinker and thereby decrosslinking the fluid to improve mobility of the agglomerants, anchorants, channelization aids and/or proppants.

[0061] A system used to implement the fracture treatment may include a pump system comprising one or more pumps to supply the treatment fluid to the wellbore and fracture. In embodiments, the wellbore may include a substantially horizontal portion, which may be cased or completed open hole, wherein the fracture is transversely or longitudinally oriented and thus generally vertical or sloped with respect to horizontal. A mixing station in some embodiments may be provided at the surface to supply a mixture of carrier fluid, proppant, agglomerant, agglomerant aid, agglomerant aid activator, viscosifier, decrosslinking agent, etc., which may for example be an optionally stabilized concentrated blend slurry (CBS) to allow reliable control of the proppant concentration, any fiber, agglomerant aid, etc., which may for example be a concentrated masterbatch to allow reliable control of the concentration of the fiber, proppant, agglomerant aid, etc., and any other additives which may be supplied in any order, such as, for example, other viscosifiers, loss control agents, friction reducers, clay stabilizers, biocides, crosslinkers, breakers, breaker aids, corrosion inhibitors, and/or proppant flowback control additives, or the like.

[0062] In some embodiments, concentrations of one or more additives, including the proppants, fibers, agglomerant aid, breaker, viscosity reducing agent or the like, to the fracturing fluid may be alternated. For example agglomerants/agglomerant aids may be alternately added, or a higher agglomerant/agglomerant aid concentration may be added, to form slugs of treatment fluid in which agglomeration and/or settling is promoted or inhibited, which may accumulate clusters during channelization, but which may be completely degraded after fracture closure to widen open voids or form additional open voids. Two or more additives (including agglomerants and/or agglomerant aids) may also be alternated independently in pulses within the proppant-laden substages.

[0063] The well may if desired also be provided with a shut in valve to maintain pressure in the wellbore and fracture, a flow-back/production line to flow back or produce fluids either during or post-treatment, as well as any conventional wellhead equipment.

[0064] If desired in some embodiments, the pumping schedule for the proppant-laden substages may be employed according to the alternating-proppant loading technology

disclosed in U.S. Patent Application Publication No. US 2008/0135242, which is hereby incorporated herein by reference.

[0065] In some embodiments, a treatment slurry stage, e.g., the proppant-laden substages thereof, has a continuous concentration of a first solid particulate, e.g., proppant, and a discontinuous concentration of an additive that facilitates either clustering of the first solid particulate in the islands, or anchoring of the clusters in the islands, or a combination thereof, to form clusters of the first solid particulate to prop open the fracture upon closure. As used herein, “anchorant” refers to a material, a precursor material, or a mechanism, that inhibits movement such as settling, or preferably stops movement, of particulates or clusters of particulates in a fracture, whereas an “anchor” refers to an anchorant that is active or activated to inhibit or stop the movement. In some embodiments, the agglomerant may be an anchorant that may comprise a material, such as fibers, flocs, flakes, discs, rods, stars, etc., for example, which may be heterogeneously distributed in the island regions of the fracture and have a different movement rate, and/or cause some of the first solid particulate to have a different movement rate, which may be faster or preferably slower with respect to the settling of the first solid particulate and/or clusters. As used herein, the term “flocs” includes both flocculated colloids and colloids capable of forming flocs in the treatment slurry stage.

[0066] In some embodiments, the agglomerant/anchorant 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 agglomerants/anchors may adhere to each other to facilitate consolidation, stability and/or strength of the formed clusters, which adherence may be mediated by the presence or generation of any binding liquid. Adherence of the agglomerants to each other and/or to the fracture surface may be promoted by a binding liquid in some embodiments.

[0067] In some embodiments, the anchorant 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 anchorant components may

react or combine to form the anchor as in a fiber/binding liquid system, a two-reactant system, a catalyst/reactant system, a pH-sensitive reactant/pH modifier system (which may be or include the decrosslinker), or the like.

[0068] In some embodiments, the anchorant may form boundaries for particulate movement, e.g., lower boundaries for particulate settling.

[0069] In some embodiments, the conductive channels extend in fluid communication from adjacent a face of 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.

[0070] In some embodiments, the proppant islands are channelized by injecting into a fracture in the formation at a continuous rate the proppant-laden substage with a continuous first solid particulate concentration; and while maintaining the continuous rate and first solid particle concentration during injection of the proppant-laden substage, successively alternating concentration modes of an anchorant, such as fiber, in pulses between a plurality of relatively anchorant-rich modes and a plurality of anchorant-lean modes within the injected treatment fluid stage.

[0071] In some embodiments, the injection of the proppant-laden substages forms a homogenous region within the proppant islands of continuously uniform distribution of the first solid particulate. In some embodiments, the alternation of pulses of the concentration of the agglomerant and/or agglomerant aid forms heterogeneous areas within the proppant islands comprising agglomerant/agglomerant aid-rich areas and agglomerant/agglomerant aid-lean areas.

[0072] In some embodiments, the agglomerant may comprise a degradable material. In some embodiments, the agglomerant 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 agglomerant may comprise acrylic fiber. In some embodiments the agglomerant may comprise mica.

[0073] In some embodiments, the agglomerant is present in the agglomerant-laden stages or pulses of the proppant-laden substages 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 agglomerant may be from 0.05 vol% less than 5 vol%, or less than 1 vol%, or less than 0.5 vol%. The agglomerant 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 0.5vol%.

[0074] In further embodiments, the agglomerant 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 agglomerant 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 agglomerant 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 agglomerant 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 agglomerant 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.

[0075] In further embodiments, the agglomerant 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.

[0076] In further embodiments, the agglomerant 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 agglomerant 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 agglomerant 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.

[0077] In some embodiments, the agglomerant 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 EVA, 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.

[0078] In some embodiments the agglomerants 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. The gel bodies may be made from the same or different polymer and/or crosslinker as the continuous crosslinked polymer phase, but may have a different viscoelastic characteristic or morphology.

[0079] In some embodiments the breaking agent may be a persulphate such as ammonium persulphate, a bromate such as sodium bromate, a chlorate or chlorite such as sodium chlorate and sodium chlorite, or enzyme. Some viscosity reducing agents may be esters such as ethyllactate, buthylglutarate, DBE esters et cetera or polyesters ssuch as PLA, PGA et cetera for borate x-linked fluids, lactates and polylactate for Zr x-linked fluids, etc. Breakers or viscosity reducing agents may be used in dissolved, solid and encapsulated forms.

[0080] In some embodiments, a system to produce reservoir fluids comprises the wellbore and the fracture resulting from any of the fracturing methods disclosed herein.

[0081] The following discussion is based on specific examples according to some embodiments wherein the first particulate comprises proppant and the agglomerant or anchor, where present, comprises fiber. In some specific embodiments illustrated below, the wellbore is oriented horizontally and the fracture is generally vertical, however, the disclosure herein is not limited to this specific configuration.

[0082] 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.

[0083] 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.

[0084] “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} .

[0085] “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.

[0086] 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.

[0087] 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.

[0088] 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.

[0089] 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 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 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 micron at 170 s^{-1} and 25°C.

[0090] 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 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 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 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 (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.

[0091] 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 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, 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 otherwise capable of being changed in shape, state, or structure.

[0092] 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 particle(s) used as anchorants or otherwise 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.

[0093] 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.

[0094] 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 US 20130233542, each of which are hereby incorporated herein by reference.

[0095] “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.

[0096] “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 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 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.

[0097] “Gravel” refers to particles used in gravel packing, and the term is synonymous with proppant as used herein. “Sub-proppant” or “subproppant” 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.

[0098] 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.

[0099] 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.

[00100] “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.

[00101] 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 “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.

[00102] 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);
- (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
- (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

- (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
- (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.

[00103] 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 $\text{SVF} = \text{PVF}$; (2) a low-shear viscosity of at least $1\text{ Pa}\cdot\text{s}$ (5.11 s^{-1} , 25°C); (3) a yield stress (as determined herein) of at least 1 Pa ; (4) an apparent viscosity of at least $50\text{ mPa}\cdot\text{s}$ (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 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 thereof.

[00104] 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 treatment fluid to at least $1\text{ Pa}\cdot\text{s}$ (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 $50\text{ mPa}\cdot\text{s}$ (170 s^{-1} , 25°C);

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) 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.

[00105] 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.

[00106] 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. 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 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 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.

[00107] In embodiments, the fluid may include leakoff control agents, such as, for example, latex dispersions, water soluble polymers, submicron particulates, 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 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 (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.

[00108] 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.

[00109] Accordingly, the present invention provides the following embodiments:

[Embodiments listing to be provided based on approved claims]

EXAMPLES

Example 1: Foam carrier fluid forming uniform clusters:

[00110] The energized fluid as disclosed was tested at room temperature, and atmospheric pressure, using artificial voids created between two plates having a space there between. The fracture width was 6 mm and the plates dimension were 100 cm by 100 cm. As would be understood, other sizes of plates could be used. The plates were made from a transparent acrylic glass, so that the settling and distribution of the

treatment slurry may be observed over time. 100 mesh sandpaper was glued to the back wall of the slot to provide roughness.

[00111] In this example, a heterogeneous proppant distribution in the slot was achieved by alternating pulses of a solid free foamed fluid and laden foamed fluid. The solid free fluid contained 60 vol% nitrogen and 40 vol% of 0.36% guar solution in water with 5 g/L of polylactide fibers (length 6 mm, diameter 12 microns), 0.5% of foaming agent (oxyalkylated alcohol), 2.4×10^{-5} g/ml of potassium hydroxide, 0.5% of triethanolamine, 0.2 g/L of ammonium persulfate. The fluid was crosslinked with 0.1% of potassium borate. The laden fluid was of similar composition, 720 g of sand of 20/40 mesh was added per liter of the foamed fluid (6 ppa).

Example 2: Foamed carrier fluid forming channels in situ:

[00112] In this example, a fracture was formed in a 37m (120ft) interval in a formation having a closure stress of 14.5MPa (2,100psi) and a stiffness of 20,700MPa (3×10^6 psi). Bottomhole static temperature was 70°C. Using a FracCADE 7.4 modeling tool, it was determined that a propped region coverage of 30% is required and a channel breadth of 1,000 mm can be supported. The fracture treatment consisted of a pad stage of 31.8m³ (200 bbls), proppant stages of 127.2 m³ (800 bbls) and flush stage of 23.9m³ (150 bbls) of water containing 2% Potassium Chloride.

[00113] The placement was achieved by alternating 6.4m³ (40 bbls) of proppant laden substages with 3.2m³ (20 bbls) of non-proppant substages. The proppant concentrations was increased according to the following schedule of 130 g of proppant per liter of carrier fluid (1ppa), 260 g/L (2ppa), 390 g/L (3ppa), 520 g/L (4ppa). The increase of concentration was done every 31.8m³ (200 bbls) of total fluid pumped (laden and clean stages). The substages were pumped at a rate of 53 L/sec (20 BPM).

[00114] The fluid used for the pad stage contained 60 vol% nitrogen and 40 vol% of 3.6×10^{-3} g/ml of guar gum solution in water, 3.6×10^{-5} g/ml of glycerol, 2.4×10^{-5} g/ml of potassium hydroxide, 7.3×10^{-5} g/ml of potassium borate, 2.4×10^{-5} g/ml of oxyalkylated

alcohol, 6.0×10^{-5} g/ml of tetramethyl ammonium chloride, 1.0×10^{-4} g/ml of triethanolamine and 1.2×10^{-4} g/ml of ammonium persulphate.

[00115] The carrier fluid contained 60 vol% nitrogen and 40 vol% of 3.6×10^{-3} g/ml of guar gum solution in water, 3.6×10^{-5} g/ml of glycerol, 2.4×10^{-5} g/ml of potassium hydroxide, 7.3×10^{-5} g/ml of potassium borate, 2.4×10^{-5} g/ml of oxyalkylated alcohol, 6.0×10^{-5} g/ml of tetramethyl ammonium chloride, 1.0×10^{-4} g/ml of triethanolamine, 1.2×10^{-4} - 3.6×10^{-4} g/ml of ammonium persulphate, and polylactic acid fibers (length 6 mm, diameter 12 microns) into the fluid at 1.2×10^{-3} g/ml.

[00116] The proppant laden fluid had a similar composition supplemented with sand of 20/40 mesh in concentration as mentioned above.

[00117] Simulated bottomhole pressure was 17.6 MPa (2550 psi). This pumping schedule and the used formulation were designed to meet the minimum proppant coverage and maximum channel breadth determined by the model.

[00118] 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 to treat a subterranean formation penetrated by a wellbore, comprising:
providing a treatment fluid stage comprising a particulate-containing substage comprising a self-agglomerating solid composition and a foamed carrying fluid;
injecting the treatment fluid stage above a fracturing pressure to place the treatment fluid stage in a fracture in the formation according to pumping parameters selected from composition of the particulate-containing substage and pumping rate of the treatment fluid stage;
alternating pulses of at least one of the pumping parameters to transform the self-agglomerating solid composition in the fracture into a channelized solids pack comprising clusters having a high concentration of solids, wherein the clusters are separated by open voids having a substantially reduced concentration of solids between the clusters; and
closing the fracture onto the clusters.
2. The method of claim 1, wherein the self-agglomerating solids composition comprises fiber.
3. The method of claim 1, wherein the transformation of the solid composition comprises destabilization of the foamed carrying fluid.
4. The method of claim 1, wherein the at least one alternated pumping parameter comprises foam quality of the carrying fluid between alternate pulses within the particulate-containing substage.
5. The method of claim 1, wherein the at least one alternated pumping parameter comprises foam quality of the carrying fluid between alternate pulses within the

particulate-containing substage, wherein the foam quality (volume percent gas) is alternated between values different by at least 5 percent.

6. The method of claim 1, wherein the at least one alternated pumping parameter comprises a concentration between alternate pulses within the particulate-containing substage of a fluid rheology component [defined as anything that changes fluid rheology, such as, for example, a viscosifier, breaker, crosslinker, decrosslinker, etc. before closing the fracture.
7. The method of claim 1, wherein the at least one alternated pumping parameter comprises a concentration of breaker between alternate pulses, wherein the breaker reduces the viscosity of the carrying fluid before closing the fracture.
8. The method of claim 1, wherein the at least one alternated pumping parameter is selected from the group consisting of crosslinker concentration, crosslinker delay agent concentration, decrosslinker concentration, fiber concentration, proppant concentration, fluid loss additive concentration, clay stabilizer concentration, pH adjusting agent concentration, and combinations thereof.
9. The method of claim 1, wherein closing the fracture comprises shutting in the wellbore and waiting for the fracture to close.
10. The method of claim 1, wherein closing the fracture comprises forced fracture closure.
11. The method of claim 1, wherein the treatment fluid stage comprises alternating a plurality of the solid particulate-containing substages with solid particulate-lean substages, wherein a volume of each of the solid particulate-containing substages is larger than a respective volume of an adjacent one of the particulate-lean substages.

12. A fracture treatment method for a subterranean formation penetrated by a wellbore, comprising:
 - considering closure stress and stiffness of an interval of the formation;
 - modeling the interval based on the closure stress and stiffness of the interval to determine a minimum coverage of propped regions in a fracture in the interval and maximum open channel breadth between the propped regions to inhibit collapse of the open channels;
 - formulating a treatment fluid stage comprising alternating solid particulate-rich and solid particulate-lean substages, wherein at least a portion of the particulate-rich substage comprises a self-agglomerating solid composition and a foamed carrying fluid, wherein a volume of each of the particulate-rich substages is larger than a respective volume of an adjacent one of the particulate-lean substages;
 - injecting the formulated treatment fluid stage above a fracturing pressure into the formation by alternately injecting the solid particulate-rich and solid particulate-lean substages into the fracture;
 - forming a plurality of particulate-rich island regions in the fracture to provide at least the minimum coverage of propped regions as determined by the modeling;
 - forming an interconnected network of open channel regions between the island regions in the fracture having a channel breadth less than the maximum channel breadth as determined by the modeling;
 - reducing pressure in the fracture to close the fracture propped on the island regions; and
 - hydraulically conducting fluid flow through the open channel regions between the formation and the wellbore.
13. The method of claim 12, further comprising channelizing the solid particulate rich island regions in situ in the fracture to form solid particulate clusters within the island regions separated from adjacent solid particulate clusters by open voids within the island regions.

14. The method of claim 1, wherein the solid particulate-rich substages and the solid particulate-lean substages in the treatment stage fluid have an overall volumetric ratio from 60:40 to 95:5.
15. A method to treat a subterranean formation penetrated by a wellbore, comprising:
 - injecting a treatment fluid stage above a fracturing pressure into the formation to distribute a mixture of a solid particulate in a fracture;
 - alternatingly injecting solid particulate-rich and solid particulate-lean substages of the treatment fluid stage into the fracture, wherein at least a portion of the particulate-rich substage comprises a self-agglomerating solid composition and a foamed carrying fluid, wherein a volume of each of the solid particulate-rich substages is larger than a respective volume of an adjacent one [immediately preceding or following] of the solid particulate-lean substages to form a plurality of solid particulate-rich island regions in the fracture and an interconnected network of open channel regions between the island regions;
 - channelizing the particulate-rich island regions in situ in the fracture to form particulate clusters within the island regions separated from adjacent particulate clusters by open voids in the island regions;
 - reducing pressure in the fracture to close the fracture onto the island regions; and
 - hydraulically conducting fluid flow through the open channel regions between the formation and the wellbore.
16. The method of claim 15, wherein the solid particulate-rich substages each comprise alternating pulses injected at different rates.
17. The method of claim 15, wherein the solid particulate-rich substages each comprise alternating pulses comprising a substantially uniform distribution of one

or more components in the alternate pulses and a heterogeneous distribution between alternate pulses of at least one other component.

18. The method of claim 15, wherein the particulate-rich substages each comprise alternating pulses comprising a substantially uniform distribution of one or more components in the alternate pulses, and a heterogeneous distribution between alternate pulses of another component selected from the solid particulate, foam quality (gas), fibers, anchorant, agglomerant, agglomerant aid, agglomerant aid activator, binding liquid, an induced settling trigger, viscous gel macrostructures, and combinations thereof.
19. The method of claim 15, wherein the particulate-rich substages each comprise alternating pulses comprising a substantially uniform distribution of one or more components with respect to a liquid phase of the carrying fluid in the alternate pulses, and a heterogeneous distribution between alternate pulses of foam quality (volume percent gas), wherein the foam quality is alternated between values different by at least 5 percent.
20. The method of claim 15, wherein the carrying fluid comprises a viscoelastic surfactant.
21. The method of claim 15, wherein the treatment fluid stage comprises a pH control agent.
22. The method of claim 15, wherein the treatment fluid stage comprises an ester and further comprising releasing an acid from the ester.
23. The method of claim 15, wherein the solid particulate-lean substages comprise fiber.

24. The method of claim 15, wherein the solid particulate-rich substages comprise a slurry of the solid particulate freely dispersed in fluid spaces around macrostructures [gel blobs or fibers] suspended in a carrying fluid.
25. The method of claim 15, wherein the solid particulate-rich substages and the solid particulate-lean substages in the treatment stage fluid have an overall volumetric ratio from 60:40 to 95:5.
26. The method of claim 15, wherein the solid particulate-rich substages provide at least a minimum coverage of propped regions comprising the islands and a channel breadth between the propped regions sufficiently small to inhibit collapse of the open channel regions in the interconnected network.
27. A system to treat a fracture interval of a formation penetrated by a wellbore, comprising:
 - a subterranean formation penetrated by a wellbore;
 - a treatment fluid stage disposed at least partially in the wellbore, the treatment fluid stage comprising solid particulate-rich and solid particulate-lean substages, wherein a volume of each of the solid particulate-rich substages is larger than a respective volume of an adjacent one of the solid particulate-lean substages to form a plurality of solid particulate-rich island regions in the fracture and an interconnected network of open channel regions between the island regions;
 - the solid particulate-rich substages each comprising alternating pulses comprising a substantially uniform distribution of one or more components with respect to a liquid phase of a carrying fluid in the alternate pulses, and a heterogeneous foam quality to channelize the particulate-rich island regions in situ in the fracture to form particulate clusters within the island regions separated from adjacent particulate clusters by open voids within the island regions;

- a pump system to pump 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; and
- a shut in system to close the fracture onto the solid particulate-rich island regions.

1/4

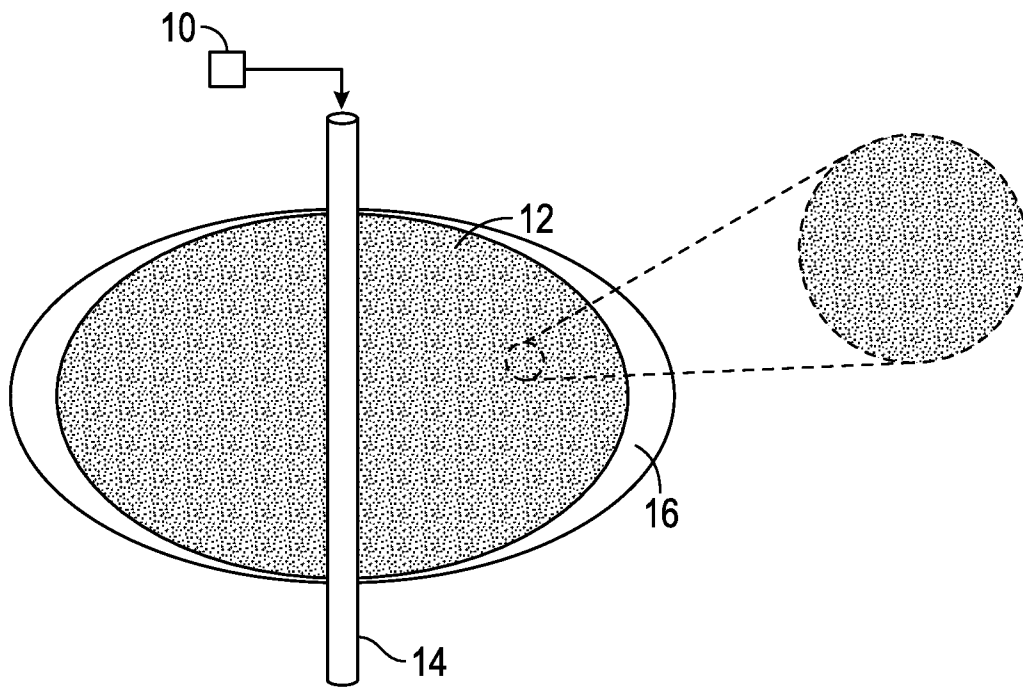


FIG. 1

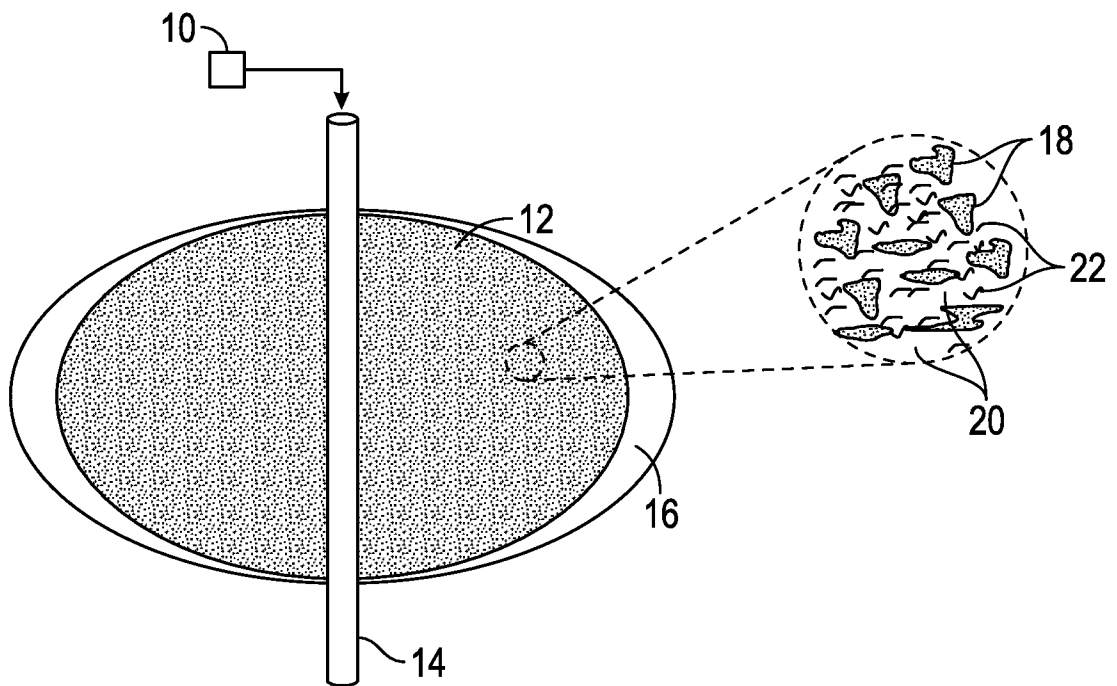


FIG. 2

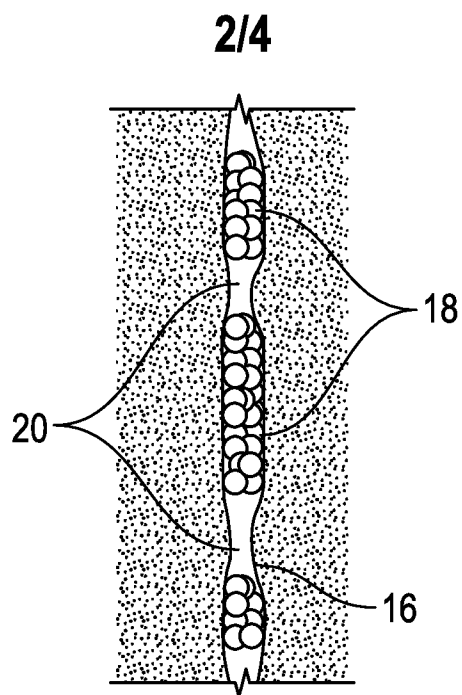


FIG. 3

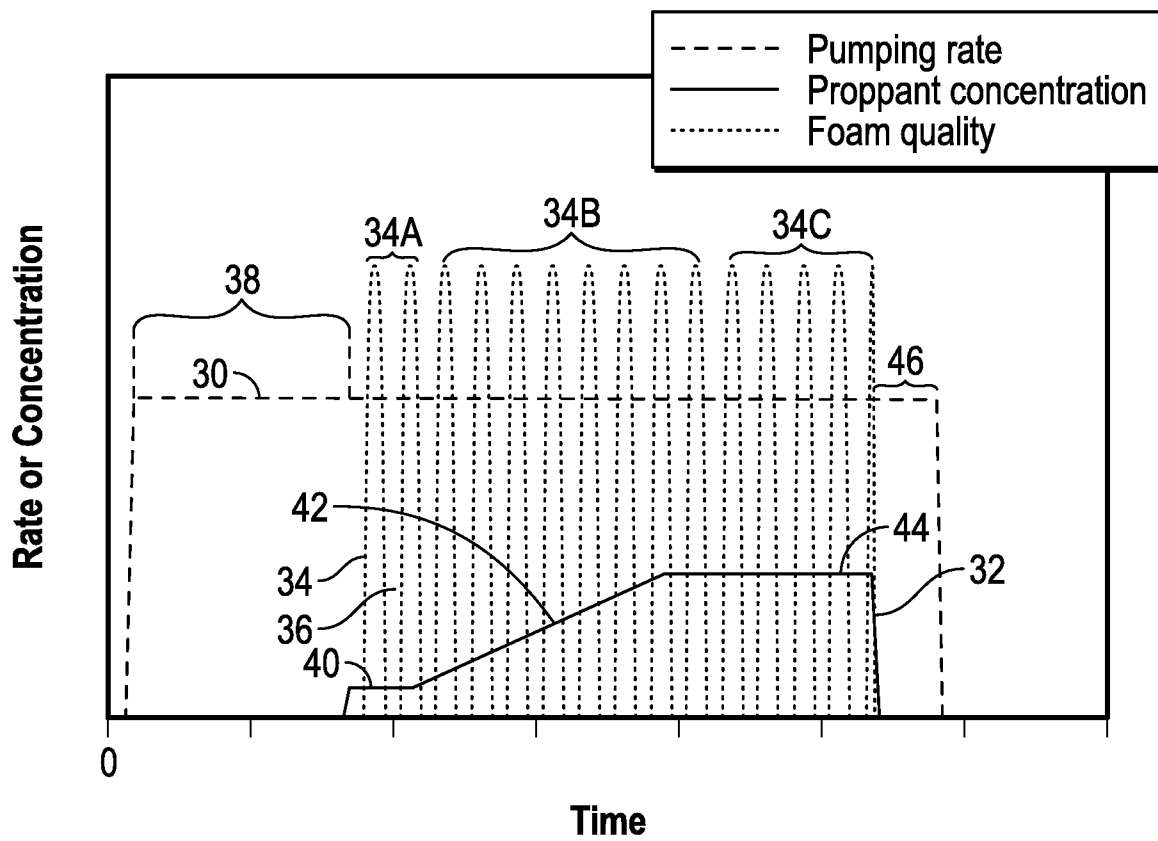


FIG. 4

3/4

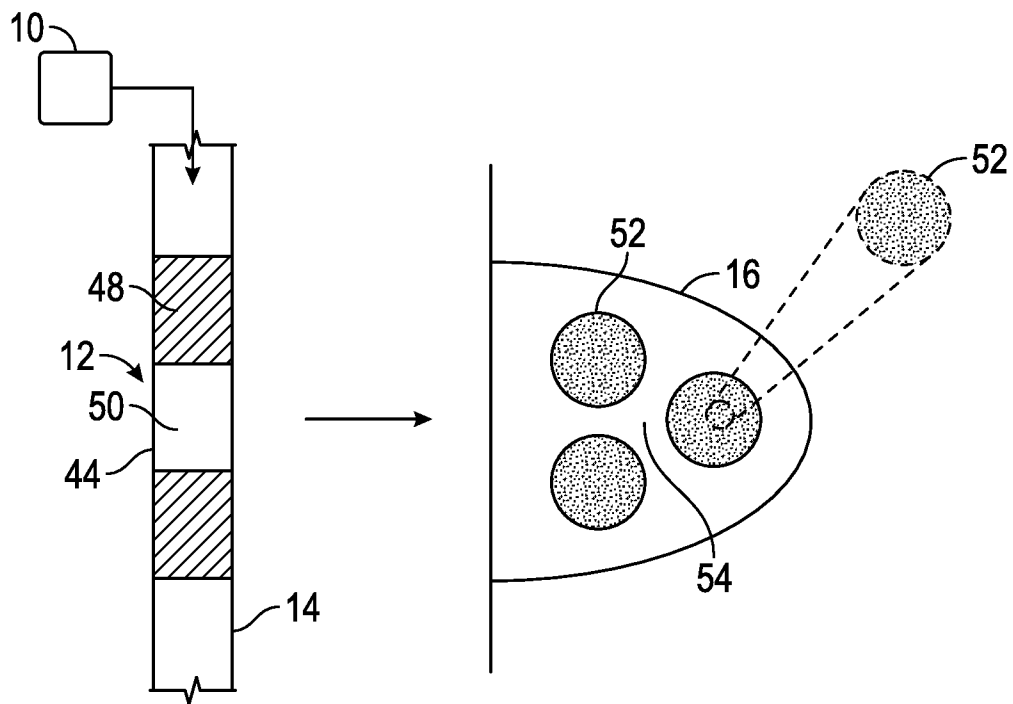


FIG. 5

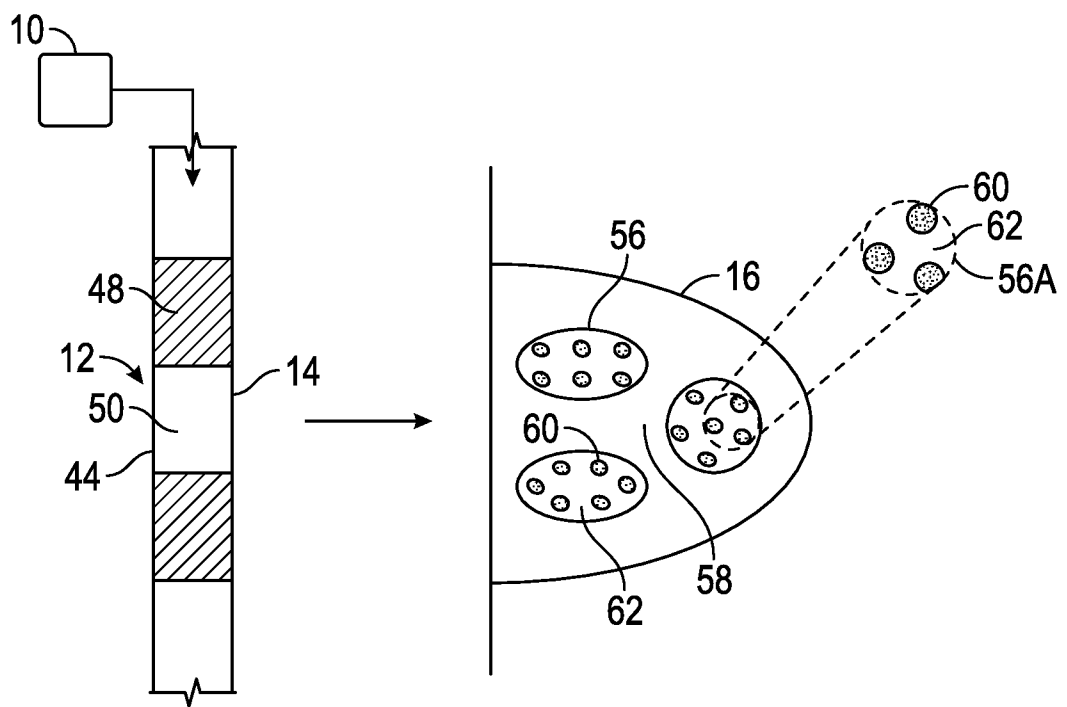


FIG. 6

4/4

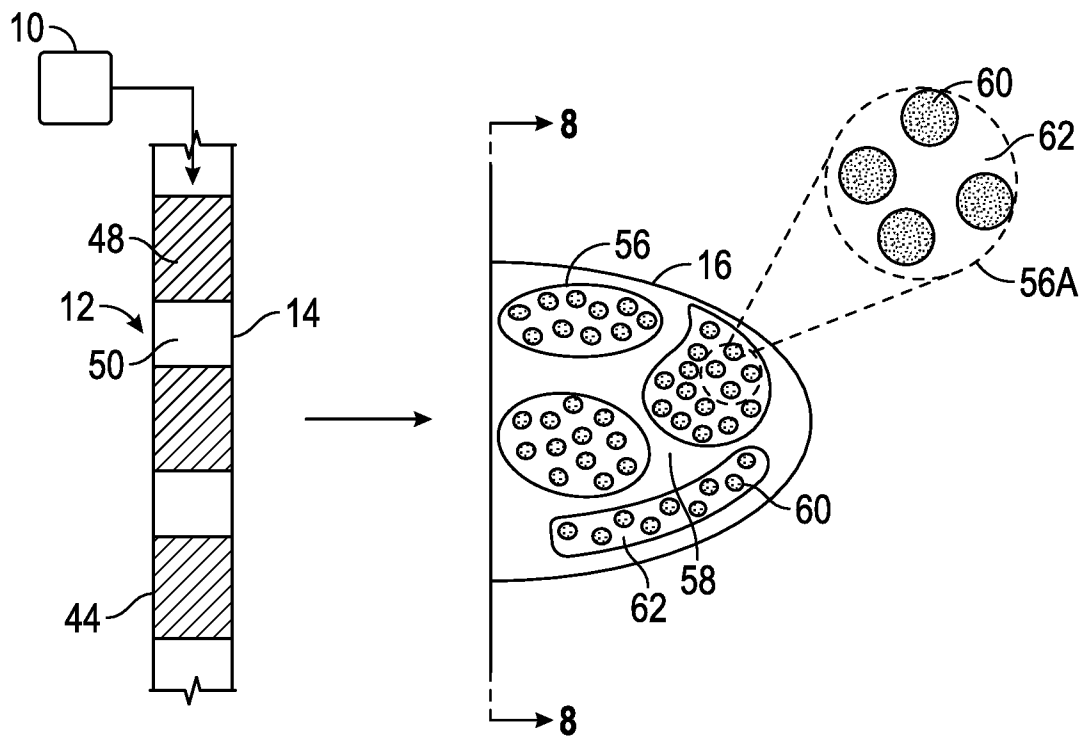


FIG. 7

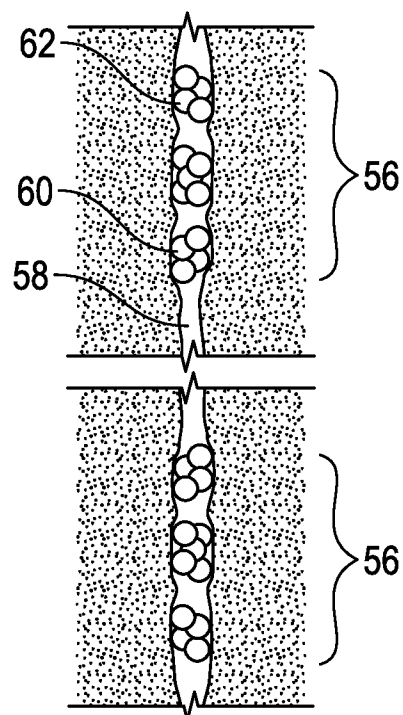


FIG. 8

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2015/035552**A. CLASSIFICATION OF SUBJECT MATTER****E21B 43/26(2006.01)i, E21B 43/247(2006.01)i, C09K 8/62(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; E21B 33/13; E21B 43/247; C09K 8/62

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: fracturing, proppant, self-agglomerating solid composition, foamed carrying fluid, pumping rate, alternating, channel, void

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2014-0144635 A1 (NGUYEN et al.) 29 May 2014 See abstract, paragraphs [0018]-[0020], [0042], [0045]-[0046], [0056]-[0057], [0061]-[0062], claims 1, 9, and figures 1-2.	1-11, 15-27
Y		12-14
Y	US 2008-0149329 A1 (COOPER et al.) 26 June 2008 See abstract, paragraph [0034], claim 1, and figure 1.	12-14
A	US 2012-0325472 A1 (LITVINETS et al.) 27 December 2012 See abstract, paragraphs [0030], [0055]-[0056], [0076], [0092], [0102], claims 1, 10, 27, and figures 1-4.	1-27
A	US 2012-0247764 A1 (PANGA et al.) 04 October 2012 See abstract, paragraphs [0018]-[0020], claim 1, and figure 1.	1-27
A	US 2011-0083849 A1 (MEDVEDEV et al.) 14 April 2011 See abstract, paragraphs [0019]-[0021], claim 1, and figures 1-2.	1-27



Further documents are listed in the continuation of Box C.



See patent family annex.

* Special categories of cited documents:

"A" document defining the general state of the art which is not considered to be of particular relevance

"E" earlier application or patent but published on or after the international filing date

"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)

"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art

"&" document member of the same patent family

Date of the actual completion of the international search

21 September 2015 (21.09.2015)

Date of mailing of the international search report

21 September 2015 (21.09.2015)

Name and mailing address of the ISA/KR

International Application Division
Korean Intellectual Property Office
189 Cheongsu-ro, Seo-gu, Daejeon Metropolitan City, 35208,
Republic of Korea

Facsimile No. +82-42-472-7140

Authorized officer

Jang, Gijeong

Telephone No. +82-42-481-8364



INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2015/035552

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
US 2014-0144635 A1	29/05/2014	None	
US 2008-0149329 A1	26/06/2008	AR 064451 A1 CA 2672852 A1 CA 2672852 C EA 011447 B1 EA 200702563 A1 MX 2009006521 A US 7451812 B2 WO 2008-075242 A1 WO 2008-075242 B1	01/04/2009 26/06/2008 23/10/2012 27/02/2009 30/06/2008 17/07/2009 18/11/2008 26/06/2008 02/10/2008
US 2012-0325472 A1	27/12/2012	CA 2841581 A1 CN 103781991 A MX 2014000436 A US 9085727 B2 WO 2013-012772 A1	24/01/2013 07/05/2014 30/04/2014 21/07/2015 24/01/2013
US 2012-0247764 A1	04/10/2012	AR 085918 A1 US 2014-131040 A9	06/11/2013 15/05/2014
US 2011-0083849 A1	14/04/2011	CA 2592799 A1 CA 2592799 C RU 0002345115 C2 RU 2006123073 A US 2008-0000638 A1 US 2008-0135242 A1 US 2009-0286700 A1 US 2011-0114313 A1 US 7581590 B2 US 7931966 B2 US 8066068 B2 US 8757259 B2 US 8763699 B2 WO 2008-068645 A1	29/12/2007 01/06/2010 27/01/2009 10/01/2008 03/01/2008 12/06/2008 19/11/2009 19/05/2011 01/09/2009 26/04/2011 29/11/2011 24/06/2014 01/07/2014 12/06/2008