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Makarychev-Mikhailov et al.(10) **Pub. No.: US 2013/0161003 A1**(43) **Pub. Date: Jun. 27, 2013**(54) **PROPPANT PLACEMENT****Publication Classification**(75) Inventors: **Sergey Mikhailovich Makarychev-Mikhailov**, St. Petersburg (RU); **Christopher N. Fredd**, Westfield, NY (US); **Trevor Hughes**, Cambridge (GB); **Evgeny Borisovich Barmatov**, Cambridge (GB); **Jill F. Geddes**, Cambridge (GB)(51) **Int. Cl.****E21B 43/267** (2006.01)(52) **U.S. Cl.**CPC **E21B 43/267** (2013.01)USPC **166/280.1**(73) Assignee: **SCHLUMBERGER TECHNOLOGY CORPORATION**, SUGAR LAND, TX (US)

(57)

ABSTRACT(21) Appl. No.: **13/520,328**(22) PCT Filed: **Dec. 31, 2009**(86) PCT No.: **PCT/RU09/00756**

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(2), (4) Date: **Mar. 12, 2013**

Embodiments of hydraulic fracturing methods disclosed herein use fine mesh proppant. In one embodiment the method is used to fracture a low permeability formation. In one embodiment the method uses flocculation to improve conductivity of a fracture. In one embodiment fluid flow through the fine mesh proppant in the fracture creates a network of connected channels to improve the fracture conductivity.

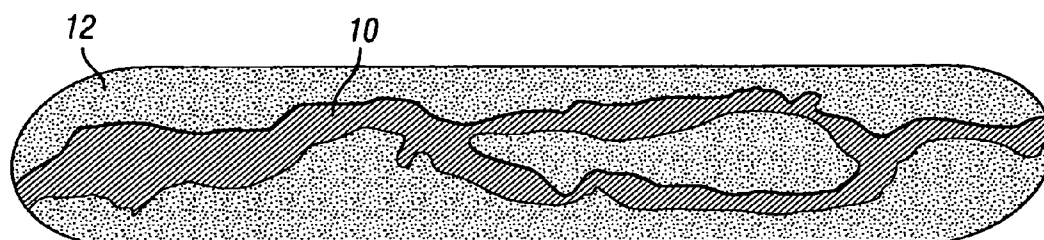


FIG. 1

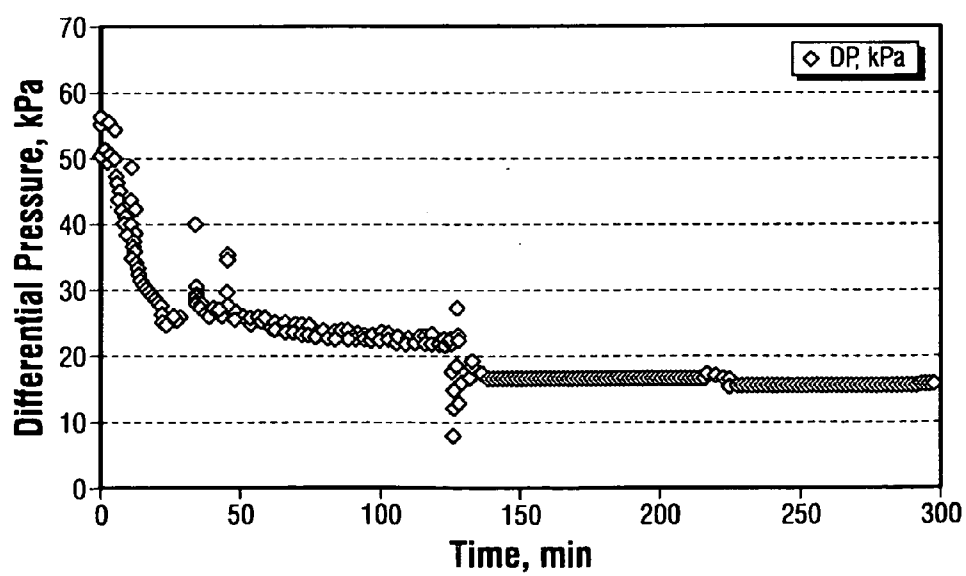


FIG. 2

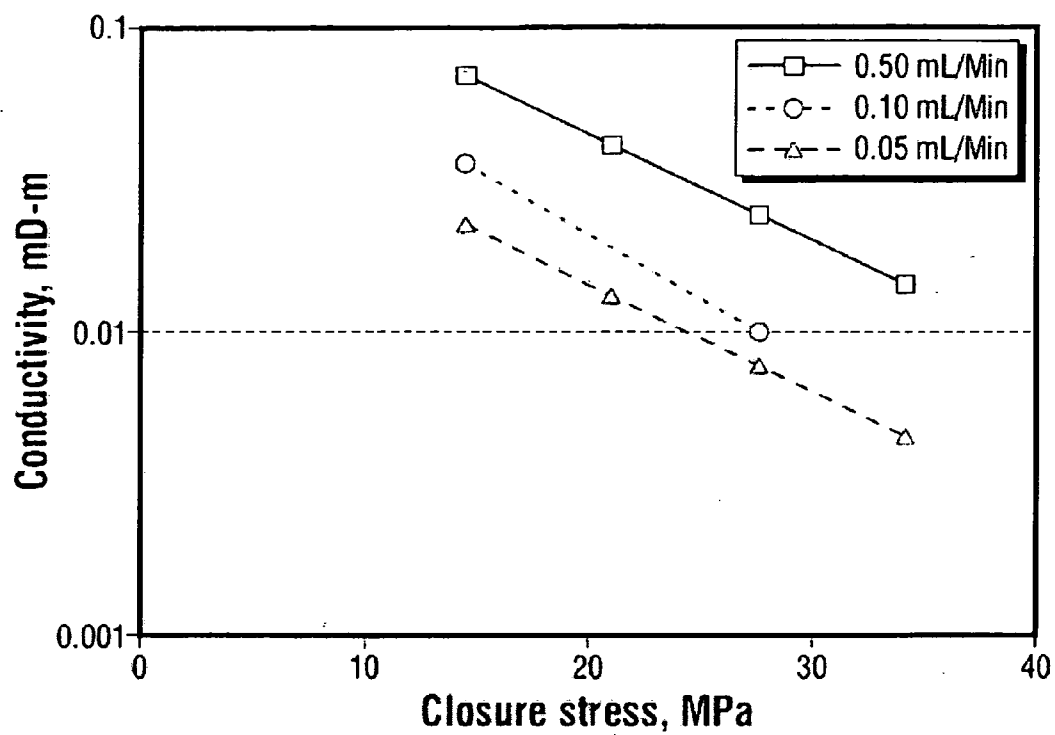


FIG. 3

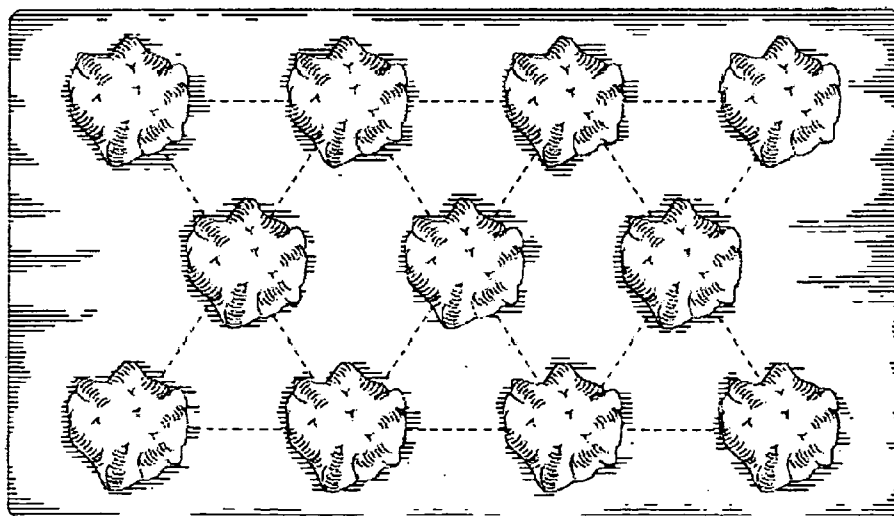


FIG. 4

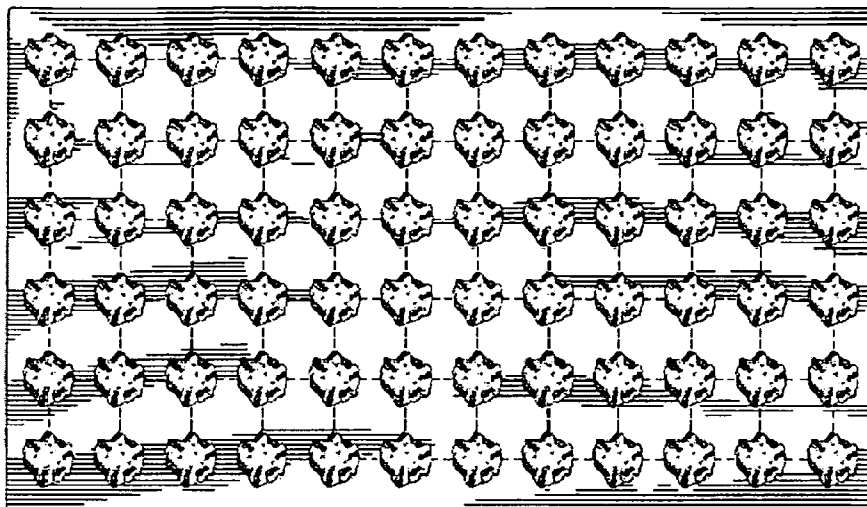


FIG. 5

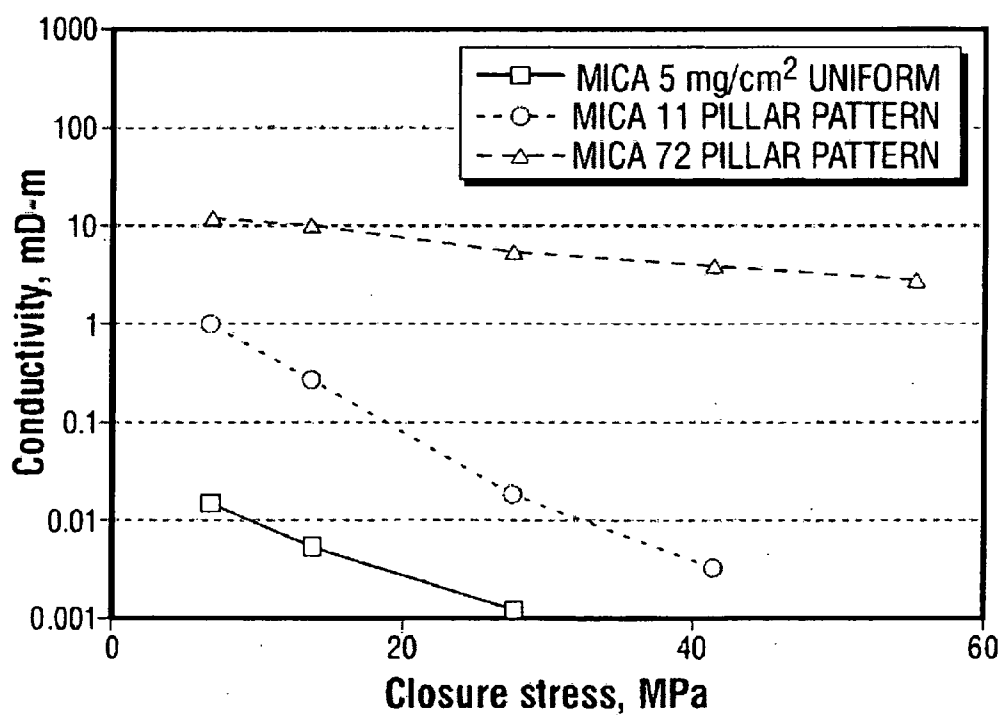


FIG. 6

PROPPANT PLACEMENT

FIELD OF THE INVENTION

[0001] The invention relates to stimulation of wells penetrating subterranean formations, and more specifically to fracturing with injection of proppant into the fracture to form one or more paths of reduced resistance to flow for the production of fluids. Embodiments of this invention are concerned with the placing of proppant in a fracture formed in a formation of low porosity such as a tight gas reservoir.

BACKGROUND

[0002] Hydraulic fracturing is an important method of reservoir stimulation, which allows significant hydrocarbon production increase. The fracturing treatment usually includes a step of pumping a fracturing fluid loaded with suspended solid particles, referred to as proppant, downhole into a subterranean formation at a pressure exceeding formation fracturing pressure. The resulting fracture is filled with the proppant material. When pumping ceases and the fracture is allowed to close, the solid proppant prevents complete closure the proppant pack further provides a conductive path for reservoir fluids to flow to the wellbore. High hydraulic conductivity of proppant packs in the fracture is considered to be a key objective of reservoir stimulation.

[0003] It is normal practice to employ solid proppant of controlled particle size distribution in order that the proppant pack has adequate fluid conductivity, i.e. is adequately porous, and to mitigate the flowback of fine particles. Post-fracture proppant flowback to the wellbore is generally regarded as a problem and an occurrence to be avoided, since it can cause proppant accumulation in the casing, a failure or fast depreciation of electrical submersible pumps, and reduced fracture conductivity due to fracture thickness loss, e.g., from the collapse of unstable moleholes. Although many materials have been used as proppants, for the fracturing of oil reservoirs it is commonplace to use so-called 20-40 sand which has a particle size distribution such that 90% by weight passes a 20 US mesh sieve but is retained by a 40 mesh sieve. Finer materials have been used and API standards recognise proppant sizes down to a size range of 70-140 US mesh. Materials which are smaller than 70-140 US mesh have been regarded as too small to use as proppants.

[0004] Hydraulic fracturing of very low permeability formations, also known as tight formations (including tight gas formations), such as the Barnett, Woodford, or Fayetteville shale formations, is common. Wells are often drilled horizontally to access the tight formations and production is then stimulated by one or usually a plurality of fracture treatments. Many of the tight gas reservoirs were fractured utilizing crosslinked gelled fluids; however, in an effort to reduce treatment costs, slick water fracturing which can also facilitate a reduced fracture height growth because of the lower fluid viscosity has emerged as the method of choice. Still, further enhancement of the stimulation of tight formations is desired.

[0005] The statements in the preceding section merely provide background information related to the present disclosure and may not constitute prior art.

SUMMARY OF THE INVENTION

[0006] We have now found that a tight formation can be fractured successfully using a fine mesh solid of smaller size

than has been conventionally recognized to be suitable for use as a proppant, combined with non-uniformity in the proppant pack.

[0007] In a first aspect, this invention provides a method of fracturing a low-permeability subterranean reservoir formation penetrated by a wellbore, comprising injecting well treatment fluid comprising proppant material into a fracture in the formation thereby forming a proppant pack therein, wherein the proppant material has a particle size distribution such that the proppant material has a median particle size less than 105 microns (140 US mesh). The proppant material may have a particle size and size distribution such that at least 90% by weight of the proppant material has a particle size less than 105 microns.

[0008] A fracture in a tight formation which is propped with a small particle size proppant may have a low final hydraulic conductivity, and yet this may be a greater conductivity than that of the unfractured formation, so that the fracturing process leads to effective stimulation despite the low conductivity achieved. In some embodiments of this invention, the method can include the steps of: fracturing a tight gas formation wherein a treatment fluid comprising fine mesh proppant materials is injected into the formation to form a fracture with a consolidated proppant pack having a relatively higher conductivity than the formation. Within embodiments of this invention, the fracturing step may be followed by producing gas, gas condensate or a combination thereof from the formation through the fracture and into a production conduit in fluid communication therewith.

[0009] Conductivity may be enhanced by non-uniformity of the proppant within the fracture. In one embodiment, the invention relates to a method, comprising: injecting well treatment fluid comprising fine mesh proppant material into a fracture in a low-permeability subterranean formation thereby forming a proppant pack; and concurrently or subsequently introducing non-uniformity in the proppant pack to form a conductive flow path for fluid flow through the propped fracture, wherein the non-uniform proppant pack has a higher conductivity relative to the uniform proppant pack at an identical closure stress (with the same proppant loading and fracture face).

[0010] Non-uniformity of the proppant distribution may arise spontaneously, for instance in the course of proppant flowback subsequent to pumping proppant into a fracture. In some forms of this invention additional steps may be taken to induce or enhance non-uniformity of proppant distribution. Thus, some embodiments of the present invention relate to a method of proppant placement in a low-permeability formation, which relies on creation of conductive channels in a proppant pack that is made of fine mesh materials. In some embodiments, methods of placement of fine proppant particulates can control the formation of stable channels in a fine proppant pack and enhance fracture conductivity.

[0011] Some forms of this invention include a step of flocculating or agglomerating a fine mesh proppant material and disposing or forming the aggregates in a formation to enhance flow of reservoir fluid therefrom. In some embodiments, the invention relates to a method comprising: injecting well treatment fluid comprising fine mesh proppant material into a fracture in a subterranean formation and providing in the fracture either a flocculating agent or a binding liquid to flocculate or agglomerate the fine mesh proppant material thereby forming a hydraulically conductive proppant pack in the fracture. Flocculation may be brought about using a flocc-

culating agent, which may be a polymeric flocculating agent. Agglomeration using a binding liquid may be brought about by providing a binding liquid in the fracture such that the binding liquid and the fine mesh proppant are similar to each other in hydrophobic/hydrophilic character but opposite to the well treatment fluid.

BRIEF DESCRIPTION OF THE DRAWINGS

[0012] FIG. 1 is a schematic representation of a branched channel network formed in a silica flour pack by washout in a standard conductivity cell according to an embodiment of the invention as described in Example 1 below.

[0013] FIG. 2 is time-trace plot of the pressure drop through a silica flour proppant pack according to an embodiment as described in Example 1 below.

[0014] FIG. 3 is a graph of the conductivity of uniform mica packs in a test cell at different fluid flow rates and closure stresses according to an embodiment as described in Example 2 below.

[0015] FIG. 4 schematically illustrates an 11-pillar arrangement of mica in preparation for testing in a conductivity test cell according to an embodiment of Example 3 below.

[0016] FIG. 5 schematically illustrates a 72-pillar arrangement of mica in preparation for testing in a conductivity test cell according to an embodiment of Example 3 below.

[0017] FIG. 6 is a graph of the conductivity of uniform and the pillared mica packs of FIGS. 4 and 5 and in a test cell at the same fluid flow rate and different closure stresses according to an embodiment as described in Example 3 below.

DETAILED DESCRIPTION

[0018] At the outset, it should be noted that in the development of any such actual embodiment, numerous implementation—specific decisions must be made to achieve the developer's specific goals, such as compliance with system related and business related constraints, which will vary from one implementation to another. Moreover, it will be appreciated that such a development effort might be complex and time consuming but would nevertheless be a routine undertaking for those of ordinary skill in the art having the benefit of this disclosure.

[0019] The description and examples are presented solely for the purpose of illustrating the preferred, embodiments of the invention and should not be construed as a limitation to the scope and applicability of the invention or embodiments thereof. While the compositions of embodiments of the present invention are described herein as comprising certain materials, it should be understood that the composition could optionally comprise two or more chemically different materials. In addition, the composition can also comprise some components other than the ones already cited. In the summary of the embodiments of invention and this detailed description, each numerical value should be read once as modified by the term "about" (unless already expressly so modified), and then read again as not so modified unless otherwise indicated in context. Also, in the summary of the embodiments of invention and this detailed description, it should be understood that a concentration range listed or described as being useful, suitable, or the like, is intended that any and every concentration within the range, including the end points, is to be considered as having been stated. For example, "a range of from 1 to 10" is to be read as indicating each and every

possible number along the continuum between about 1 and about 10. Thus, even if specific data points within the range, or even no data points within the range, are explicitly identified or refer to only a few specific, it is to be understood that inventors appreciate and understand that any and all data points within the range are to be considered to have been specified, and that inventors possession of the entire range and all points within the range.

[0020] As used herein, the expression "and/or" in a series is inclusive of any one, plurality or all of the series members, including all combinations and permutations thereof.

[0021] As used herein, the term "low-permeability formation" refers to formations having a permeability less than 1 millidarcy, and in various embodiments, less than 100 microdarcy, less than 10 microdarcy, less than 1 microdarcy, or less than 500 nanodarcy. These formations have such low permeability that the wells can be effectively stimulated in one embodiment with an overall or primary final fracture conductivity on the order of 0.3 to 30 mD-m (1 to 100 mD-ft) and/or with secondary and/or tertiary fractures on the order of 0.003 to 30 mD-m (0.01 to 100 mD-ft), where secondary fractures are understood to refer to usually relatively smaller fractures in length and/or width branching from the primary fractures, and tertiary fractures to usually relatively smaller fractures in length and/or width branching from the secondary fractures.

[0022] As used herein, the term "open channels" refers to interconnected passageways formed in the proppant-fracture structure. Open channels are distinct from interstitial passages between individual proppant particles in the proppant matrix in that the channels are relatively large scale flow paths that exceed the dimensions of a proppant grain in at least one direction. Such open channels generally have a hydraulic radius, and hence a hydraulic conductivity larger than that of interstitial flow passages through the proppant matrix, and that in one embodiment is at least an order of magnitude larger than that of interstitial flow passages through the proppant matrix.

[0023] As used herein the term "fine mesh materials" refers to proppant materials having a relatively smaller grain size than proppant sizes recognized under American Petroleum Institute Recommended Practices (API RP) standards 56 and/or 60. These standards call for particle sizes to be determined by a sieve analysis procedure. They recognize a number of sizes of sand or other proppant for fracturing, denoting them as falling between upper and lower sieve mesh sizes stated as X/Y and require that at least 90 wt % of the particles pass the sieve of size X which defines an upper boundary but are retained on a sieve of size Y which defines the lower boundary. Mesh sizes recognized under API RP standard 56 are 6/12, 8/16, 12/20, 16/30, 20/40, 30/50, 40/70, and 70/140 for sand. Some of these are also recognized under RP 60 for other proppant materials. The smallest of these recognized sizes is 70/140 (sieve openings of 210 and 105 micron). The full specification for 70/140 sand requires that not more than 0.1 wt % is retained on a 50 mesh (300 micron) sieve, 90 wt % passes 70 mesh but is retained on 140 mesh and not more than 1% passes a 200 mesh (75 micron) sieve. All mesh sizes provided herein refer to the mesh size as measured using the US Sieve Series unless otherwise stated. It will be appreciated that the sieve analysis procedure does not determine the value of the median or mean particle size but of course if 90 wt % of the particles lie between 70 and 140 mesh then the median particle size will also lie between these mesh sizes.

[0024] The fine mesh proppant used in embodiments of this invention may be such that at least 90 wt % is smaller than an upper limit selected from approximately 150 microns (100 US mesh), approximately 125 microns (120 US mesh), approximately 105 microns (140 US mesh), approximately 88 microns (170 US mesh), approximately 74 microns (200 US mesh), approximately 63 microns (230 US mesh), approximately 53 microns (270 US mesh), approximately 44 microns (325 US mesh), and approximately 37 microns (400 US mesh).

[0025] It may be the case that the median particle size is not greater than 105 micron or perhaps not greater than 90 or 75 micron. Median particle size, denoted as d_{50} may be determined by the commonly used technique of low angle laser light scattering, more commonly known as laser diffraction. Instruments for carrying out this technique are available from a number of suppliers including Malvern Instruments Ltd., Malvern, UK. The Malvern Mastersizer is a well known instrument which determines the volumes of individual particles, from which mean and median particle size can be calculated using computer software which accompanies the instrument. When determining particle sizes using such an instrument, the size of an individual particle may be taken as the diameter of a spherical particle of the same volume, the so-called "equivalent sphere". Volume median diameter denoted as $D[v,05]$ or d_{50} is a value of particle size such that 50% (by volume) of the particles have a volume larger than the volume of a sphere of diameter d_{50} and 50% of the particles have a volume smaller than the volume of a sphere of diameter d_{50} .

[0026] The fine mesh proppant used in embodiments of this invention may be such that at least 90 wt % is larger than a lower limit selected from approximately 0.5 microns, approximately 1 microns, approximately 2 microns, approximately 5 microns, approximately 10 microns, approximately 20 microns, approximately 30 microns, approximately 37 microns (400 US mesh), approximately 44 microns (325 US mesh), approximately 53 microns (270 US mesh), approximately 63 microns (230 US mesh), approximately 74 microns (200 US mesh), and approximately 88 microns (170 US mesh).

[0027] In one embodiment, the injected treatment fluid is essentially free of proppant and/or other solids larger than fine mesh materials, e.g., to the extent that the larger materials do not adversely impact the ability to form channels in the resulting proppant pack by fluid flowback or washout. In an embodiment, the treatment fluid does not contain any larger materials that are deliberately added to the treatment fluid or proppant material. In other embodiments, the injected treatment fluid can contain a relatively small proportion of solids that are larger than the fine mesh materials, such as for example, less than about 10, 5, 3, 2, 1, 0.5, 0.2, 0.1 or 0.01 weight percent of larger solid materials, by total weight of solids. In other embodiments, the weight percentage of fine mesh materials relative to the total weight of solids in the treatment fluid, can range from above a lower limit of from 5, 10, 20, 30, 40, 50, 60, 75, 80, 90, 95, 97, 98, 99, 99.5, 99.8, 99.9 or 99.99 weight percent, up to any higher upper limit selected from 50, 60, 75, 80, 90, 95, 97, 98, 99, 99.5, 99.8, 99.9, 99.99 or 100 weight percent.

[0028] Proppant used in this application may not necessarily require the same permeability and conductivity properties as typically required in conventional treatments because the overall fracture permeability will at least partially develop

from formation of stable, open channels. For example, within API RP standard 60, the sphericity of a proppant particle may be evaluated by the method of Section 6.2, and the roundness may be evaluated by the method of Section 6.3. Standard 60 recommends a minimum sphericity of 0.7 and minimum roundness of 0.7. In embodiments of this invention, however, the fine mesh proppant material can have sphericity less than 0.7, 0.6, 0.5, 0.4, or 0.3, roundness less than 0.7, 0.6, 0.5, 0.4, or 0.3, or sphericity and roundness both less than 0.7, 0.6, 0.5, 0.4, or 0.3, or any such combination of sphericity and roundness. In addition, the proppant material can be of other shapes such as cubic, rectangular, plate-like, or combinations thereof.

[0029] Suitable fine mesh or larger proppant materials can include sand, gravel, glass beads, ceramics, bauxites, glass, and the like or combinations thereof. In an embodiment, the fine mesh proppant material can be selected from silica, muscovite, biotite, limestone, Portland cement, talc, kaolin, barite, fly ash, pozzolan, alumina, zirconia, titanium oxide, zeolite, graphite, carbon black, aluminosilicates, biopolymer solids, synthetic polymer solids, and the like, including combinations and mixtures thereof. Thus, various proppant materials like plastic beads such as styrene divinylbenzene, and particulate metals may be used. Other proppant materials may be materials such as drill cuttings that are circulated out of the well. Also, naturally occurring particulate materials may be used as fine mesh or larger proppants, including, but not necessarily limited to: ground or crushed shells of nuts such as walnut, coconut, pecan, almond, ivory nut, brazil nut, etc.; ground or crushed seed shells (including fruit pits) of seeds of fruits such as plum, olive, peach, cherry, apricot, etc.; ground or crushed seed shells of other plants such as maize (e.g., corn cobs or corn kernels), etc.; processed wood materials such as those derived from woods such as oak, hickory, walnut, poplar, mahogany, etc., including such woods that have been processed by grinding, chipping, or other form of comminution, processing, etc, some nonlimiting examples of which are proppants made of walnut hulls impregnated and encapsulated with resins. Resin coated (various resin and plastic coatings) or encapsulated proppants having a base of any of the previously listed propping materials such as sand, ceramics, bauxite, nut shells, etc. may be used in accordance with embodiments of the invention.

[0030] Essentially, the proppant can be any fine mesh material that will hold open the propped portion of the fracture.

[0031] The selection of proppant may involve balancing proppant long-term strength, proppant distribution characteristics and proppant cost. Relatively inexpensive, low-strength materials, such as sand, can be used for hydraulic fracturing of formations with small internal stresses. Materials of greater cost, such as ceramics, bauxites and others, may be used in formations with higher internal stresses.

[0032] As already mentioned, in some forms of this invention the proppant is not placed uniformly in the fracture. The proppant may be placed in spaced pillars that resist crushing upon being subjected to the fracture closure stress. In another embodiment, flow channels can be formed in the fine mesh proppant, by washout, for example, and the remaining proppant pack or matrix bounding the channels can sufficiently resist crushing to prevent the fracture closure stress from completely closing off the flow channels.

[0033] Non uniform placing of the proppant relaxes some constraints on the choice of proppant material because flow conductivity is provided by channels between 'islands' or

pillars of proppant rather than by the porosity or permeability of the packed proppant matrix. The availability of the option to select a wider range of proppant materials can be an advantage in embodiments of the present invention. For example, proppant can have a range of mixed, variable diameters or other properties that yield a high-density, high-strength pillar, which can form a proppant matrix that has high or low porosity and high or low permeability (proppant porosity and permeability are not so important in an embodiment of this invention because fluid production through the proppant matrix is not required). Or, an adhesive or reinforcing material that would plug a conventional proppant pack can be employed in the interstitial spaces of the fine mesh proppant matrix herein, such as, for example, a polymer which can be further polymerized or crosslinked in the proppant.

[0034] In one embodiment, a non-uniformity, such as, for example, at least one open channel or a branching complex network of open channels is introduced into the proppant pack by fluid flow before, during or after fracture closure. The fine mesh proppants can have a higher ratio of drag force to mass than relatively larger particles such as conventional proppant, which ratio is generally inversely proportional to the particle diameter, such that they are more easily mobilized. Moreover, smaller particles provide relatively more particle layers which can be conducive to the formation of non-uniform stresses in the proppant pack. By flowing a proppant-lean or proppant-free fluid through the proppant pack, it is relatively easy to form and wash out a connected network of flow channels through the proppant pack. In various embodiments of this invention, a proppant-lean fluid which induces non-uniformity can be injected from the wellbore or can comprise backflow to the wellbore, or fluid produced from the formation into the fracture and toward the wellbore, or some combination thereof.

[0035] One known method for heterogenous proppant placement which may be used in this invention is to pump a fluid containing suspended proppant alternately with a fluid containing less of the suspended proppant or none at all. This approach is the subject of U.S. Pat. No. 6,776,235. Another known method which may be employed is to pump the proppant together with a removable material, referred to as a 'channelant'. After pumping has ceased and the fracture has closed onto proppant in the fracture, removal of the channelant leaves open pathways between islands or pillars of the proppant. This approach is the subject of WO2008/068645, the disclosure of which is incorporated herein by reference.

[0036] Characteristics of the proppant and channelant can be selected to facilitate segregation of proppant from the channelant-rich regions depending on the manner in which segregation is effected, downhole conditions, the channelant, the treatment fluid, etc. In an embodiment, a degradable channelant material is selected from substituted and unsubstituted lactide, glycolide, polylactic acid, polyglycolic acid, copolymers of polylactic acid and polyglycolic acid, copolymers of glycolic acid with other hydroxy-, carboxylic acid-, or hydroxycarboxylic acid-containing moieties, copolymers of lactic acid with other hydroxy-, carboxylic acid-, or hydroxycarboxylic acid-containing moieties, and mixtures of such materials. Representative examples are polyglycolic acid or PGA, and polylactic acid or PLA. These materials function as solid-acid precursors, and upon hydrolytic degradation in the fracture, can form acid species which can have secondary functions in the fracture.

[0037] A further possibility for creating non-uniformity of the proppant in the fracture is to cause the proppant particles to cluster together after they have been placed in the fracture. This approach facilitates travel of the proppant into and along a fracture, because the particles are small and separately suspended in a fracturing fluid, which may be particularly important in the context of fracturing a tight gas shale, but then brings the particles together to form islands or pillars within the fracture. These serve to prop the fracture while leaving open flow paths between them. The proppant particles could also be made to cluster while being pumped in the wellbore or in the fracture.

[0038] Clustering particles into aggregates, so that they are no longer uniformly distributed within the fracture may be done in several ways. One way to aggregate proppant particles is to use particles which have been precoated with an adhesive so that the proppant can have a self-adherent surface, e.g. by coating the proppant with an adhesive or tackifier, or grafting an adhesive or tackifying compound to the proppant. In one version of the self-adherent proppant, the proppant is loosely held together in cohesive slugs or globules of a gel or lightly crosslinked, flowable polymer for which the proppant has a differential affinity, e.g. the proppant can be grafted to the gel-forming polymer.

[0039] In one embodiment the proppant can be present in the treatment fluid that is injected into the fracture in the form of an immiscible fluid packet or globule dispersed in a more or less continuous phase of a second fluid. The immiscible fluid proppant packets can each contain sufficient proppant to form a suitably sized island, singly from isolated packet placement or in combination with one or more additional proppant packets where cumulative packet placement can occur. Because the open channels to be formed must interconnect between the wellbore and the remote exposed surfaces in the fracture, it can be convenient to provide the proppant-lean fluid in a continuous phase in the treatment fluid in which the proppant packets are a dispersed or discontinuous phase. In one version, the proppant packets can be provided with a thin encapsulating skin or deformable bladder to retain the proppant and remain flowable during injection, and the bladder can be optionally ruptured or chemically or thermally removed during placement in the fracture and/or during closure of the fracture.

[0040] A further possibility is that an adhesive coating is over-coated by a layer of non-adhesive substance which is degradable or dissolvable in the fracture as the fracture treatment fluid or another fluid it passes through the fracture. A non-adhesive substance inhibits the formation of proppant agglomerates prior to entering the fracture, and allows for control of a time moment in the fracture when, corresponding to a place where, a proppant particle gains its adhesive properties.

[0041] An adhesive coating can be cured at the formation temperature. Bonding particles together within proppant pillars can inhibit erosion of the proppant pillar as formation fluids flow past, and minimize ultimate proppant island destruction by erosion.

[0042] Another possibility for aggregating proppant is to contact the proppant particles, in the fracture, with a material which causes them to aggregate. Such material may enhance attractive forces between particles, reduce repulsive forces or create bridges joining particles together. The effect of aggregation is of course to reduce the number of particles by clustering them into particles as part of a larger size. As used

herein, the term 'degree of aggregation' refers to the ratio of the number of particles in a system before aggregation divided by the number of aggregates after aggregation. In embodiments, the degree of aggregation may range from a low limit of 2, 3, 5, or 10, up to infinity, i.e., monolithicity or one aggregate.

[0043] Aggregation of particles may be brought about with flocculating agents, i.e., a chemical agent such as a coagulant like alum and/or a flocculant like a polyacrylamide, which act on a molecular level on the surface chemistry of the particles to facilitate attractive forces and/or to inhibit repulsive forces.

[0044] Flocculating agents in one embodiment are inorganic, such as trivalent salts of aluminum and iron, activated silica or the like, or organic, such as natural organic flocculants including water-soluble starch, e.g., corn and potato, guar gum, alginates, chitin derivatives, glue, gelatin and the like, and such as synthetic polymers, which may be nonionic or ionic. Flocculating agents in an embodiment can include alum, prepolymerized or preoligomerized aluminum compounds, polyaluminum chloride, polyaluminum-silicate-sulfate, ferric chloride, ferric sulfate, ferrous sulfate, polyferric sulfate, polyphosphorous iron chloride, lime, starch, albumin, polysaccharides, and polymers and copolymers of at least one monomer selected from acrylamide, methacrylamide, N-vinylmethacrylamide, N-vinylmethacrylamide, vinyl acetate, acrylate esters, methacrylate esters, cyanoacrylate esters, vinyl pyrrolidone, and the like, and combinations and mixtures thereof.

[0045] Specific representative examples of nonionic polymers can include polyacrylamide, poly(ethylene oxide), polymers of 1-vinyl-2-pyrrolidone, polymers of N-vinylformamide, polymers of methoxyethylene, hydrolyzed polymers of poly(vinyl acetate) (i.e., polyvinyl alcohol), and the like.

[0046] Anionic polymeric flocculants in an embodiment are prepared as homopolymers or acrylamide copolymers of the alkali metal or ammonium salts of acrylic acid, methacrylic acid, ethylenesulfonic acid, 4-styrenesulfonic acid, 2-methyl-2-[(1-oxo-2-propenyl)amino]-1-propanesulfonic acid, 2-acrylamido-2-propanesulfonic acid, and the like.

[0047] Cationic polymeric flocculants in an embodiment can include polymers comprising monomers and/or comonomers such as substituted acrylamide and methacrylamide salts, e.g., methacrylamidopropyltrimethylammonium chloride, acryloyloxyethyltrimethylammonium chloride, methacryloyloxyethyltrimethylammonium chloride and N,N-dimethylaminoethyl methacrylate, N-vinylformamide and N-vinylacetamide which are hydrolyzed in alkaline or acid to vinylamine copolymers, salts of N-vinylimidazole, 2-vinylpyridine, 4-vinylpyridine, dialkyldiallylammonium chlorides (e.g., dialkyldimethylammonium chloride), and the like. Polyamines, e.g., prepared by polycondensation of alkylene dichlorides or epichlorohydrin and ammonia, low molecular weight alkylene polyamines, or polyaminoamides.

[0048] Specific representative examples of ionic polymers can include poly(sodium acrylate), poly[2-(N,N,N-trimethylamino)-ethyl acrylate] (chloride salt), polyethylenimine, poly[N-(dimethylamino-methyl)acrylamide], and the like. Functional groups on embodiments of modified polyacrylamides can include Mannich amines formed by reaction with dimethylamine and formaldehyde, quaternized Mannich amines, carboxylate formed by acid or base catalysis, hydrox-

amate formed by transamination with hydroxylamine, and the like. Further, combinations and mixtures of flocculating agents can be used.

[0049] Polymeric flocculating agents are commercially available, in embodiments, as solid, dry powders or granules, invert emulsions, two-phase aqueous solutions. Additional information on flocculants is available from, for example, Howard Heitner, "Flocculating Agents," *Kirk-Othmer Encyclopedia of Chemical Technology*, 5th Ed., John Wiley & Sons, Inc., vol. 11, pp. 623-647 (2004); and Hans Burkert et al., "Flocculants," *Ullmann's Encyclopedia of Industrial Chemistry*, 5th Ed., Wiley-VCH Verlag GmbH & Co. KGaA, Weinheim 10.1002/14356007.all 251 (2005); both of which are incorporated herein by reference in their entirety in jurisdictions where permitted.

[0050] The flocculating agents serve in an embodiment to bind the fine mesh materials together in a floc. Where high molecular weight ionic polymers are used in an embodiment, some segments of the polymer adsorb on a surface of the fine mesh proppant, and large segments extend into the liquid phase where other segments are adsorbed onto other fine mesh particles, linking the particles together by polymer bridges. The size of the flocs in an embodiment is controlled by the ratio of polymer to fine mesh proppant, charge densities of the polymer and fine mesh particles, mixing conditions such as shear rate, addition point, polymer concentration and dilution, pH, ionic strength, temperature, viscosity and the like. In one embodiment, the flocs are reversibly shear sensitive so that only limited or small floc formation occurs under high shear conditions such as during pumping down the wellbore, and large flocs form after the high shear condition is removed, for example, after placement in a fracture and during shut-in and fracture closure. The flocculation process in the fracture promotes a heterogeneous proppant placement resulting in the formation of channels of proppant clusters and/or between proppant flocs.

[0051] In one embodiment, a combination of cationic and anionic polymers is used, for example, an initially added cationic polymer can neutralize cationic charges on the fine mesh particles and form charge patches that present adsorption sites for the later added anionic polymer. In embodiments, flocs produced by bridging with high molecular weight polymers can be stronger or harder than other types of flocs, while charge patch neutralization can allow the bridges to reform if broken, for example, by high shear conditions. In an embodiment, larger flocs are more conducive to heterogeneity, the formation of a connected network of channels between the floc clusters, and/or conductivity of the propped fracture.

[0052] Yet another possibility for the aggregation of proppant particles is the use of a binding liquid. We have found that agglomeration can be caused by providing a binding liquid which exists as a separate phase within the fracturing fluid and where the binding liquid and proppant are similar to each other but opposite to the fracturing fluid in hydrophilic/hydrophobic character such that agglomerates of the solid proppant held together by the binding liquid are formed at the subterranean location.

[0053] The agglomeration of solid particles by one liquid in the presence of another is a known phenomenon. The agglomeration takes place if there is sufficient similarity in surface polarity between the two constituents which agglomerate, namely the binding liquid and the particulate proppant, and also sufficient contrast between both of these and the fractur-

ing fluid, so that agglomeration leads to a reduction in the total surface energy of the system. Generally, when all three materials are present together, the contact angle of the binding liquid to the solid surface should be low, while the contact angle of the fracturing fluid on the solid is high. The binding liquid then serves to hold the agglomerated solid particles in proximity to each other. The contact angle of the binding liquid on the surface of the solid may be sufficiently low that the binding liquid wets and spreads on the solid surface. The fracturing fluid and the binding liquid must of course remain as separate phases when placed in contact with each other.

[0054] The binding liquid and the particulate proppant may be transported as such in the fracturing fluid from the surface to the subterranean location. However, it is also possible that one or the other of them will be transported from the surface in the form of a precursor which then undergoes transformation below ground to become the binding liquid or the particulate proppant having the required hydrophilic/hydrophobic character. It is also possible to mix the binding liquid and proppant particle downhole, for example by pumping the binding liquid down coiled tubing while the proppant travels down the annulus around the coiled tubing.

[0055] The fracturing fluid may be hydrophilic and indeed may be aqueous, while the solid particles, the binding liquid and the agglomerates which form are all hydrophobic. The inverse arrangement is also possible, however, in which the fracturing fluid is hydrophobic while the binding liquid and the solid particles are both hydrophilic. Whether they are hydrophilic or hydrophobic, the agglomerates which are formed will be made up of the solid particles wetted by the binding liquid and thereby agglomerated together. When the agglomerates are hydrophobic, the dispersed binding liquid may be a hydrocarbon. A vegetable oil might possibly be used. A silicone oil such as a non-volatile polydimethylsiloxane would also be a possibility. Although they are somewhat more expensive than hydrocarbon mixtures such as kerosene, silicone oils have the useful property of being very hydrophobic. Fluorocarbon oils are also very hydrophobic and would be a further possibility.

[0056] It is possible that the viscosity of the binding liquid phase might be increased by using an oil thickened with oil-soluble polymer(s) and/or other oil-soluble thickening agents

[0057] In order that there is spontaneous agglomeration, the dispersed binding liquid and the particulate proppant must be sufficiently similar in hydrophobicity (or where appropriate hydrophilicity) that the binding liquid selectively wets the solid when they are both submerged within the fracturing fluid. A sufficiently hydrophobic particulate proppant may be a material which is inherently hydrophobic (rubber for example) or it may be a material to which a surface treatment has been applied in order to make it more hydrophobic (or where appropriate more hydrophilic) in order that agglomeration occurs. We have observed that particulate solids which are very hydrophobic form tight agglomerates with the solid particles closely packed together, whereas solids which are only just sufficiently hydrophobic to be agglomerated by a hydrophobic oil tend to form loose agglomerates characterised by a high volume fraction of oil within them and the solid particles lying at the oil-water interface.

[0058] Sand is frequently used as proppant in conventional fracturing. Ordinary silica sand is not agglomerated by oil in the presence of water. By contrast, we have found that sand

which has been treated to make it more hydrophobic will spontaneously agglomerate in the presence of oil.

[0059] A range of different methods can be used to modify the surface of solid particles to become more hydrophobic, and preferably sufficiently hydrophobic to form tight agglomerates—these include the following:

[0060] Organo-silanes can be used to attach hydrophobic organo-groups to hydroxyl-functionalised mineral substrates such as proppants composed of silica, silicates and aluminosilicates. The use of organosilanes with one or more functional groups (for example amino, epoxy, acyloxy, ethoxy or chloro) to apply a hydrophobic organic layer to silica is well known. The reaction may be carried out in an organic solvent or in the vapour phase (see for example Duchet et al, *Langmuir* (1997) vol 13 pp 2271-78).

[0061] Organo-titanates and organo-zirconates such as disclosed in U.S. Pat. No. 4,623,783 can also be used. Published literature indicates that organo-titanates can be used to modify minerals without surface hydroxyl groups, which could extend the range of materials to undergo surface modification, for instance to include carbonates and sulphates.

[0062] A polycondensation process can be used to apply a polysiloxane coating containing organo-functionalised ligand groups of general formula $P-(CH_2)_3-X$ where P is a three-dimensional silica-like network and X is an organo-functional group. The process involves hydrolytic polycondensation of a tetraalkoxysilane $Si(OR)_4$ and a trialkoxy silane $(RO)_3Si(CH_2)_3X$. Such coatings have the advantage that they can be prepared with different molar ratios of $Si(OR)_4$ and $(RO)_3Si(CH_2)_3X$, making it possible to provide some control of the hydrophobicity of the treated surface.

[0063] A fluidised bed coating process can be used to apply a hydrophobic coating to a particulate proppant substrate. The coating material would typically be applied as a solution in an organic solvent and the solvent then evaporated within the fluidised bed.

[0064] Adsorption methods can be used to attach a hydrophobic coating on a mineral substrate. A surfactant monolayer can be used to change the wettability of a mineral surface from water- to oil-wet. Hydrophobically modified polymers can also be attached by adsorption.

[0065] A waxy coating can be used to render a mineral substrate hydrophobic. Typically, the wax is applied at a temperature above its melting point and subsequent cooling forms a competent hydrophobic coating.

[0066] The agglomerates which form consist of the solid particles clustered together, with binding liquid in the spaces between particles. The amount of binding liquid may or may not be sufficient to fill completely the spaces between the solid particles in the agglomerates.

[0067] We have observed that the ratio of binding liquid to solid particles affects the equilibrium size of the agglomerates which form. As the proportion of binding liquid is increased from zero, the equilibrium size of the agglomerates increases until the proportion of binding liquid approaches the amount (which can be calculated) needed to fill the spaces between randomly close packed particles in a large agglomerate. If the amount of binding liquid is increased still further, some excess liquid may associate with the agglomerates.

[0068] If non-uniformity of proppant distribution in a fracture is induced or enhanced by contacting the proppant with a material which causes it to aggregate, it will be desirable that this material does not contact the proppant prematurely. It will generally be necessary to provide some way to avoid or

inhibit agglomeration during transit but then permit or induce agglomeration on arrival within the fracture. There are a number of ways in which this can be done and these will be discussed in turn.

[0069] Separate Flow Paths:

[0070] The flocculant or binding liquid is delivered by a flow path within a wellbore which is separate from the flow-path for proppant. This can be achieved by using coiled tubing within a wellbore to deliver one of the two components which form aggregates while using the annulus around the coiled tubing as the flow path for the other of the two components. For instance, a suspension of the binding liquid in fracturing fluid might be pumped through coiled tubing to the point at which the materials pass from the wellbore into the reservoir while a suspension of the particulate solid in fracturing fluid is pumped through the annulus around the coiled tubing. It is possible that the concentration of binding liquid might then be cycled between higher and lower (or zero) concentrations in order to promote the formation of discreet agglomerates for heterogeneous proppant placement.

[0071] Sensitivity to Temperature:

[0072] This approach makes use of the difference between surface temperatures and temperatures below ground, which are almost always higher than at the surface. During transit to the subterranean location, the carrier liquid and everything suspended in it will pass through a wellbore exposed to subterranean temperatures and will begin to heat up, but if the flow rate is substantial, the flowing composition will leave the wellbore and enter the fracture at a temperature significantly below the reservoir temperature.

[0073] One way to make use of this temperature difference is to employ as a binding liquid a substance which is solid at surface temperature but which melts to a liquid at the downhole temperature. One example of such a material is eicosane which melts at 35 to 37° C. Various grades of paraffin wax, melting at temperatures from 35 to 60° C., are available commercially. It is envisaged that the solid wax could be blended with the particulate solid and pumped in as a suspension in aqueous carrier liquid. Higher and lower (or zero) concentrations of the wax in the carrier liquid could be pumped alternately in order to promote the formation of discreet agglomerates for heterogeneous proppant placement.

[0074] Encapsulation:

[0075] Encapsulation of either the binding liquid or the particulate proppant to delay release and prevent them from contacting each other prematurely could also be carried out with an encapsulating material which dissolves slowly or undergoes chemical degradation under conditions encountered at the subterranean location, thereby leading to rupture of the encapsulating shell or making the encapsulating material permeable. Degradation may in particular be hydrolysis which de-polymerises an encapsulating polymer. While such hydrolytic degradation may commence before the overall composition has travelled down the wellbore to the reservoir, it will provide a delay before significant amounts of binding liquid or particulate proppant contact each other.

[0076] A number of technologies are known for the encapsulation of one material within another material. Polymeric materials have frequently been used as the encapsulating material. Some examples of documents which describe encapsulation procedures are U.S. Pat. No. 4,986,354, WO 93/22537, and WO 03/106809. Encapsulation can lead to particles in which the encapsulated substance is distributed as

a plurality of small islands surrounded by a continuous matrix of the encapsulating material. Alternatively encapsulation can lead to core-shell type particles in which a core of the encapsulated substance is enclosed within a shell of the encapsulating material. Both core-shell and islands-in-matrix type encapsulation may be used.

[0077] An encapsulating organic polymer which undergoes chemical degradation may have a polymer chain which incorporates chemical bonds which are labile to reaction, especially hydrolysis, leading to cleavage of the polymer chain. A number of chemical groups have been proposed as providing bonds which can be broken, including ester, acetal, sulfide and amide groups. Cleavable groups which are particularly envisaged are ester and amide groups both of which provide bonds which can be broken by a hydrolysis reaction.

[0078] Generally, their rate of cleavage in aqueous solution is dependent upon the pH of the solution and its temperature. The hydrolysis rate of an ester group is faster under acid or alkaline conditions than neutral conditions. For an amide group, the decomposition rate is at a maximum under low pH (acidic) conditions. Low pH, that is to say acidic, conditions can also be used to cleave acetal groups.

[0079] Thus, choice of encapsulating polymer in relation to the pH which will be encountered after the particles have been placed in a fracture may provide a control over the delay before the encapsulated material is released. Polymers which are envisaged for use in encapsulation include polymers of hydroxyacids, such as polylactic acid and polyglycolic acid. Hydrolysis liberates carboxylic acid groups, making the composition more acidic. This lowers the pH which in turn accelerates the rate of hydrolysis. Thus the hydrolytic degradation of these polymers begins somewhat slowly but then accelerates towards completion and release of the encapsulated material. Another possibility is that a polymer containing hydrolytically cleavable bonds may be a block copolymer with the blocks joined through ester or amide bonds.

[0080] One possibility for making use of chemical degradation to delay agglomeration would be to coat a hydrophobic proppant with a degradable coating. The coating would need to be hydrophilic in order to prevent agglomeration. Degradation of the coating would expose the hydrophobic solid inside and allow agglomeration to proceed.

[0081] Another possibility would be to apply a degradable coating to particles of a substance which is solid at surface temperature but melts to become a binding liquid at downhole temperatures. The solid state at the surface will facilitate coating and availability of the binding liquid is delayed until degradation of the coating and exposure to downhole temperature have both taken place.

[0082] A further possibility would be to encapsulate a flocculating agent within a polymer which degrades to release the flocculating agent.

[0083] Precursor Converts to Binding Liquid:

[0084] One approach to delaying agglomeration by means of a binding liquid and so providing time for transport to a fracture before agglomeration takes place, is to transport binding liquid in the form of a precursor and induce it to transform from the precursor to the binding liquid below ground. This may be done by using a long chain carboxylic acid as the binding liquid, transporting it at a pH above the pK_a of the acid so that it is in the form of an ionised salt, and then lowering the pH after a delay.

[0085] Suitable monocarboxylic acids may have the formula $RCOOH$ where R is a saturated or unsaturated aliphatic

carbon chain of at least 8 carbon atoms. Possibly R has a chain length of 8 or 12 carbon atoms up to 24 carbon atoms. Also suitable are dimeric and oligomeric carboxylic acids based on linked surfactant monomer subunits, each monomer subunit having the formula $R_a\text{COOH}$ where R_a is a C_{10} - C_{50} aliphatic group comprising a C_{10} - C_{25} aliphatic chain and the R_a groups of the monomer subunits are connected together to form the dimeric or oligomeric acid. These dimeric and oligomeric acids would provide a very viscous binding liquid. Some structures of dimeric, trimeric and oligomeric fatty acids are shown in U.S. Pat. No. 6,774,094.

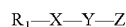
[0086] If these carboxylic acids contain an aliphatic chain of sufficient length, generally of at least 16 or 18 carbon atoms, they are able to act as viscoelastic surfactants when the pH is above their pK_a values so that the surfactants are in ionised form. In order to obtain viscoelastic behaviour it may be necessary that the solution also contains some added salts such as potassium chloride (KCl). Incorporating such carboxylic acids, when in the form of viscoelastic surfactants at pH above their pK_a values and in the presence of a salt will have the effect of thickening the carrier liquid. After a carrier liquid containing a carboxylate has been transported down-hole to a subterranean location, it will be necessary to reduce pH to below the pK_a value of the acid. One possibility for this would be to pump in an acid solution alternately with the carrier liquid and allowing them to mix. However, a preferred way to reduce pH with a delay is to include particles of a poly(hydroxyacid) such as polylactic acid or polyglycolic acid in the composition transported down the wellbore. The polymer will hydrolyse on contact with the aqueous carrier liquid as described above, liberating the carboxylic acid groups of the monomeric acid and thus lowering the pH of the solution.

[0087] Using a precursor which is a viscoelastic surfactant is advantageous in hydraulic fracturing, where it is desirable that the carrier liquid is a thickened aqueous fluid but it is also desirable that it loses viscosity after the proppant has been transported into the fracture. Lowering the pH when the composition has been delivered to the fracture or other subterranean location will take away the viscoelastic property of the precursor at the same time as converting it from a viscoelastic surfactant into the required binding liquid.

[0088] Another category of precursor capable of hydrolysis to form a hydrophobic binding liquid is a molecule including the partial formula



where R_1 is a long chain aliphatic group and X is a cleavable group such as an ester, amide or acetal group cleavable by hydrolysis. Such a precursor compound may be a cleavable surfactant having the structure



where (i) R_1 is a saturated or unsaturated, linear or branched aliphatic chain of at least 8 carbon atoms, preferably at least 12 carbon atoms;

(ii) X is a cleavable group such as an $O(CO)$, $(CO)O$, $R_7N(CO)$, or $(CO)NR$, group;

(iii) Y is a spacer group which is constituted by a short saturated or unsaturated hydrocarbon chain comprising at least one carbon atom, preferably at least 2 but not more than 6 carbon atoms and which may optionally be a branched if the

number of carbon atoms is sufficient for a branched chain; (iv) Z is a hydrophilic head group which may be:

[0089] a cationic group of the formula $-N^+R_2R_3R_4$;

[0090] a sulfonate or carboxylate anionic group; or

[0091] an amphoteric group of the formula $-N^+R_2R_3R_4-COO^-$; and

(v) R_2 , R_3 , R_4 and R_7 are each independently hydrogen; a linear or branched, saturated aliphatic chain of at least 1 carbon atom; or a linear or branched, saturated aliphatic chain of at least 1 carbon atom with one or more of the hydrogen atoms replaced by a hydroxyl group.

[0092] A further possibility for a precursor of a binding liquid is an ionic complex formed between a polymer with multiple positive charges and negatively charged carboxylate ions. When pH is reduced the carboxylate ions will be converted to the un-ionised carboxylic acid and be able to serve as binding liquid.

[0093] Emulsified Binding Liquid or Flocculating Agent:

[0094] Yet another approach to delaying aggregation is to emulsify a flocculating agent or a binding liquid in the fracturing fluid, thereby inhibiting interaction of the binding liquid or flocculant with the particulate proppant, and then break the emulsion after transport to the fracture. This approach may be implemented by forming an emulsion with an emulsifier which undergoes hydrolytic degradation, for example, a surfactant which includes a degradable ester or degradable amide linkage.

[0095] There are a number of possibilities for additional features and details. In one embodiment, reinforcing and/or consolidating material can be introduced into the fracture fluid to increase the strength of the proppant clusters formed and prevent their collapse during fracture closure. The reinforcing material in one embodiment can facilitate flocculation of the fine mesh proppant. If proppant-rich and proppant-lean substages are pumped alternately the reinforcement material can be added to either substage. The concentrations of both proppant and the reinforcing materials can vary in time throughout the proppant stage, and from substage to substage. That is, the concentration of proppant reinforcing material can be different at two subsequent substages. It can also be suitable in some applications of the present method to introduce the reinforcing material in a continuous or semi-continuous fashion throughout the proppant stage, or during one or a plurality of adjacent proppant-lean substages. Particularly, different implementations can be preferable when the concentration of the reinforcing material does not vary during the entire proppant stage; monotonically increases during the proppant stage; or monotonically decreases during the proppant stage.

[0096] On the other hand, a high permeability and/or high porosity proppant pack can be suitably employed without detriment. In one embodiment, the permeability of the fine mesh proppant can provide some limited fracture conductivity in the event the channels are not properly formed or do not fully interconnect. Additionally, under some formation conditions it can be advantageous when using the present method to perform a final tail-in stage of the fracturing treatment involving continuous proppant introduction into the fracturing fluid, with the proppant at this stage consisting essentially of uniform particle size, which can be larger than or free of fine mesh proppant materials, to obtain a zone of continuous-porosity proppant adjacent to the wellbore. If employed, the tail-in stage of the fracturing treatment resembles a conventional fracturing treatment, where a continuous bed of well-sorted conventional proppant is placed in the fracture relatively near to the wellbore. The tail-in stage can involve introduction of both an agent that increases the proppant

transport capability of the treatment fluid and/or an agent that acts as a reinforcing material. The tail-in stage is distinguished from the second stage by the continuous placement of a well-sorted proppant, that is, a proppant with an essentially uniform particle size. The proppant strength is sufficient to prevent its cracking (crumbling) when subjected to stresses that occur at fracture closure. The role of the proppant at this tail stage is to prevent fracture closure and, therefore, to provide good fracture conductivity in proximity to the wellbore.

[0097] One embodiment of the method of proppant placement includes completion of a wellbore and perforations in the case of a cased hole. Fine mesh proppant particles can be injected in a fracturing fluid through the wellbore and into a fracture. A well treatment fluid may comprise at least about 4.8 g/litre (0.04 ppg), or at least about 48 g/litre (0.4 ppg) or even at least about 480 g/litre (4 ppg) of added fine mesh proppant. After sufficient time for flocculation to occur in an embodiment where a flocculating agent is employed, the fracture can then be allowed to close, and the flocculated proppant compressed in the fracture to prevent the opposing fracture faces from contacting each other and provide an interconnected network of flow channels around the proppant flocs or aggregated flocs. In an alternative or additional embodiment, a backflow of fluid from the formation is initiated through the fine mesh proppant to the wellbore and the fluid washes out channels around consolidated proppant clusters or islands.

[0098] Where a degradable or soluble material such as a channelant is employed with the fine mesh proppant, the channelant can be removed in various embodiments by flushing, dissolving, softening, melting, breaking, or degrading the channelant, wholly or partially, via a suitable activation mechanism, such as, but not limited to, temperature, time, pH, salinity, solvent introduction, catalyst introduction, hydrolysis, and the like, or any combination thereof. The activation mechanism can be triggered by ambient conditions in the formation, by the invasion of formation fluids, exposure to water, passage of time, by the presence of incipient or delayed reactants in or mixed with the channelant particles, by the post-injection introduction of an activating fluid, or the like, or any combination of these triggers.

[0099] In some fracturing embodiments, a solid acid-precursor can be present in the fine mesh proppant or between proppant stages. Suitable acid-generating dissolvable channelants can include for example, and without limitation, PLA, PGA, carboxylic acid, lactide, glycolide, copolymers of PLA or PGA, and the like and combinations thereof. Provided that the formation rock is carbonate, dolomite, sandstone, or otherwise acid reactive, then the hydrolyzed product, a reactive liquid acid, can etch the formation at surfaces exposed between the proppant pillars. This etching can enlarge the open channels and thus further enhance the conductivity between the pillars. Other uses of the generated acid fluid can include aiding in the breaking of residual gel, facilitating consolidation of proppant clusters, curing or softening resin coatings and increasing proppant permeability.

[0100] In some embodiments, a fluoride source capable of generating hydrofluoric acid upon release of fluorine and adequate protonation can be present in the fine mesh proppant or between proppant stages. Some nonlimiting examples of fluoride sources which are effective for generating hydrofluoric acid include fluoboric acid, ammonium fluoride, ammonium bifluoride, and the like, or any mixtures thereof.

[0101] During hydraulic fracturing, high pressure pumps on the surface inject the fracturing fluid into a wellbore adjacent to the face or pay zone of a geologic formation. The first stage, also referred to as the “pad stage” involves injecting a fracturing fluid into a borehole at a sufficiently high flow rate and pressure sufficient to literally break or fracture a portion of surrounding strata at the sand face. The pad stage is pumped until the fracture has sufficient dimensions to accommodate the subsequent slurry pumped in the proppant stage. The volume of the pad can be designed by those knowledgeable in the art of fracture design, for example, as described in *Reservoir Stimulation*, 3rd Ed., M. J. Economides, K. G. Nolte, Editors, John Wiley and Sons, New York, 2000.

[0102] Water-based fracturing fluids are common, with natural or synthetic water-soluble polymers optionally added to increase fluid viscosity, and can be used throughout the pad and subsequent proppant and/or channelant stages. These polymers include, but are not limited to, guar gums; high-molecular-weight polysaccharides composed of mannose and galactose sugars; or guar derivatives, such as hydroxypropyl guar, carboxymethyl guar, carboxymethylhydroxypropyl guar, and the like. Cross-linking agents based on boron, titanium, zirconium or aluminum complexes are typically used to increase the effective molecular weight of the polymer for use in high-temperature wells.

[0103] To a small extent, cellulose derivatives, such as hydroxyethylcellulose or hydroxypropylcellulose and carboxymethylhydroxyethylcellulose, are used with or without cross-linkers. Two biopolymers—xanthan and scleroglucan—provide excellent proppant suspension, but are more expensive than guar derivatives and so are used less frequently. Polyacrylamide and polyacrylate polymers and copolymers are typically used for high-temperature applications or as friction reducers at low concentrations for all temperatures ranges.

[0104] Friction reducers may also be incorporated into fluids in one embodiment of the invention. Any friction reducer may be used. In addition, polymers such as polyacrylamide, polyisobutyl methacrylate, polymethyl methacrylate and polyisobutylene as well as water-soluble friction reducers such as guar gum, guar gum derivatives, hydrolyzed polyacrylamide, and polyethylene oxide may be used. Commercial drag reducing chemicals such as those sold by Conoco Inc. under the trademark “CDR” as described in U.S. Pat. No. 3,692,676 (Cutter et al.) or drag reducers such as those sold by Chemlink designated under the trademarks FLO 1003, FLO 1004, FLO 1005 and FLO 1008 have also been found to be effective.

[0105] Polymer-free, water-base fracturing fluids can also be obtained using viscoelastic surfactants. Usually, these fluids are prepared by mixing in appropriate amounts of suitable surfactants, such as anionic, cationic, nonionic, amphoteric, and zwitterionic. The viscosity of viscoelastic surfactant fluids are attributed to the three-dimensional structure formed by the fluid's components. When the surfactant concentration in a viscoelastic fluid significantly exceeds a critical concentration, and in most cases in the presence of an electrolyte, surfactant molecules aggregate into species, such as worm-like or rod-like micelles, which can interact to form a network exhibiting viscous and elastic behavior.

[0106] In another embodiment, a slickwater fracturing fluid containing a friction reducer can be used in the pad and/or proppant stages.

[0107] In one embodiment, after the fracture is induced, fine mesh proppant and any flocculant can be injected into the fracture as a slurry or suspension of particles in the fracturing fluid during what is referred to herein as the "proppant stage." In the proppant stage, proppant is injected in one or more segregated substages having alternated proppant concentration, pumping rates and/or fluid rheologies to facilitate a heterogeneous proppant placement during the injection. As a result, the proppant does not completely fill the fracture. Rather, spaced proppant clusters form as pillars with channels between them, through which formation fluids can pass. The volumes of proppant and carrier sub-stages as pumped can be different. That is, the volume of the substages can be varied. Furthermore, the volumes and order of injection of these substages can change over the duration of the proppant stage. That is, proppant substages pumped early in the treatment can be of a smaller volume than a proppant substage pumped later in the treatment. The relative volume of the substages can be selected by the engineer based on how much of the surface area of the fracture it is desired to be supported by the clusters of proppant, and how much of the fracture area is desired as open channels through which formation fluids are free to flow.

[0108] The use of an optional degradable material or channelant in one embodiment can depend on the mode of channelant segregation and placement in the fracture, as well as the mode of channelant removal and channel formation. In its simplest form, the channelant can be a solid participate that can be maintained in its solid form during injection and fracture closure, and readily dissolved or degraded for removal. Materials that can be used can be organic, inorganic, glass, ceramic, nylon, carbon, metallic, and so on. Suitable materials can include water- or hydrocarbon-soluble solids such as, for example, salt, calcium carbonate, wax, or the like. Polymers can be used in another embodiment, including polymers such as, polylactic acid (PLA), polyglycolic acid (PGA), polyol, polyethylene terephthalate (PET), polysaccharide, wax, salt, calcium carbonate, benzoic acid, naphthalene based materials, magnesium oxide, sodium bicarbonate, soluble resins, sodium chloride, calcium chloride, ammonium sulfate, and the like, and so on, or any combinations thereof. The channelant can be selected to have a size and shape similar or dissimilar to the size and shape of the proppant particles as needed to facilitate segregation from the proppant. Channelant particle shapes can include, for example, spheres, rods, platelets, ribbons, and the like and combinations thereof. In some applications, bundles of fibers, or fibrous or deformable materials, can be used. These fibers can additionally or alternatively form a three-dimensional network, reinforcing the proppant and limiting its flowback.

[0109] For example, the separation of injected proppant and channelant as introduced and placed in the fracture can be induced by differences (or similarities) in size, density or shape of the two materials. The specific gravities and the volume concentrations of proppant and channelant can be tailored to minimize mixing and homogenization during placement. Properly sizing the channelant or adding various weighting agents to the channelant-rich fluid can facilitate segregation at the appropriate time and location.

[0110] The presence of the channelant in the fracturing fluid in the proppant stage, e.g. in a mixed substage or in a segregated channelant substage, can have the benefit of increasing the proppant transport capability. In other words, the channelant can reduce the settling rate of proppant in the fracture treatment fluid. The channelant can in an embodiment be a material with elongated particles having a length that much exceeds a diameter. This material can affect the

rheological properties and suppress convection in the fluid, which can result in a decrease of the proppant settling rate in the fracture fluid and maintain segregation of the proppant from proppant lean regions.

[0111] The fibers injected with the fine mesh proppant in an embodiment can be capable of decomposing in the water-based fracturing fluid or in the downhole fluid, such as fibers made on the basis of polylactic acid (PLA), polyglycolic acid (PGA), polyvinyl alcohol (PVOH), and others. The fibers can be made of or coated by a material that becomes adhesive at subterranean formation temperatures. They can be made of adhesive material coated by a non-adhesive substance that dissolves in the fracturing fluid or another fluid as it is passed through the fracture. The fibers used in one embodiment can be up to 2 mm long with a diameter of 10-200 microns, in accordance with the main condition that the ratio between any two of the three dimensions be greater than 5 to 1. In another embodiment, the fibers can have a length greater than 1 mm, such as, for example, 1 to 30 mm, 2 to 25 mm or 3 to 18 mm, e.g. about 6 mm; and they can have a diameter of 5 to 100 microns and/or a denier of about 0.1 to 20, preferably about 0.15 to 6. These fibers in one embodiment are desired to facilitate proppant carrying capability of the treatment fluid with reduced levels of fluid viscosifying polymers or surfactants, and in another embodiment can facilitate flocculation. Fiber cross-sections need not be circular and fibers need not be straight. If fibrillated fibers are used, the diameters of the individual fibrils can be much smaller than the aforementioned fiber diameters.

[0112] The weight concentration of the fibers in the fracturing fluid can be from 0.1 to 10 percent in one embodiment. The concentration of the solid channelant material in the treatment fluid in another embodiment is typically from about 0.6 g/L (about 5 ppt) to about 9.6 g/L (about 80 ppt).

[0113] In an embodiment, a fiber additive can provide reinforcement and consolidation of the fine mesh proppant. This fiber type can include, for example, glass, ceramics, carbon and carbon-based compounds, metals and metallic alloys, and the like and combinations thereof, as a material that is packed in the proppant to strengthen the proppant pillars: In other applications, a second type of fiber can be used that inhibits or accelerates flocculation and/or settling of the proppant in the treatment fluid. The second fiber type can include, for example, polylactic acid, polyglycolic acid, polyethylene terephthalate (PET), polyol, and the like and combinations thereof, as a material that inhibits settling or dispersion of the proppant in the treatment fluid and serves as a primary removable fill material in the spaces between the pillars. In another embodiment, a third fiber type can be insoluble and provide surface charged sites to facilitate flocculation. Yet other applications include a mixture of the first, second and/or third fiber types.

[0114] The fibers can be hydrophilic or hydrophobic in nature. Hydrophilic fibers are used in one embodiment where the fiber modifies flocculation. Fibers can be any fibrous material, such as, but not necessarily limited to, natural organic fibers, comminuted plant materials, synthetic polymer fibers (by non-limiting example polyester, polyaramide, polyamide, novoloid or a novoloid-type polymer), fibrillated synthetic organic fibers, ceramic fibers, inorganic fibers, metal fibers, metal filaments, carbon fibers, glass fibers, ceramic fibers, natural polymer fibers, and any mixtures thereof. Particularly useful fibers are polyester fibers coated to be highly hydrophilic, such as, but not limited to, DACRON® polyethylene terephthalate (PET) Fibers available from Invista Corp. Wichita, Kans., USA, 67220. Other examples of useful fibers include, but are not limited to,

polylactic acid polyester fibers, polyglycolic acid polyester fibers, polyvinyl alcohol fibers, and the like.

[0115] If desired, a pH control agent can be used in the treatment fluid, especially where a solid acid precursor is present and one or more of the other treatment fluids are pH-sensitive. The pH control agent can be selected from amines and alkaline earth, ammonium and alkali metal salts of sesquicarbonates, carbonates, oxalates, hydroxides, oxides, bicarbonates, and organic carboxylates, for example sodium sesquicarbonate, triethanolamine, or tetraethylene-pentamine.

[0116] Suitable solid acids for use in viscoelastic surfactant (VES) fluid systems include substituted and unsubstituted lactide, glycolide, polylactic acid, polyglycolic acid, a copolymer of polylactic acid and polyglycolic acid, a copolymer of glycolic acid with other hydroxy-, carboxylic acid-, or hydroxycarboxylic acid-containing moieties, a copolymer of lactic acid with other hydroxy-, carboxylic acid or hydroxycarboxylic acid-containing moieties, or mixtures of the preceding. Other materials suitable for use in VES fluid systems are all those polymers of hydroxyacetic acid (glycolic acid) with itself or other hydroxy-, carboxylic acid-, or hydroxycarboxylic acid-containing moieties described in U.S. Pat. No. 4,848,467; U.S. Pat. No. 4,957,165; and U.S. Pat. No. 4,986,355. Suitable solid acids are also described in U.S. Pat. No. 7,166,560, which is hereby incorporated by reference.

[0117] Embodiments of the invention may use other additives and chemicals that are known to be commonly used in oilfield applications by those skilled in the art. These include, but are not necessarily limited to, materials in addition to those mentioned hereinabove, such as breakers, breaker aids, amino acids, oxygen scavengers, alcohols, scale inhibitors, corrosion inhibitors, fluid-loss additives, bactericides, iron control agents, organic solvents, and the like.

[0118] A buffering agent may be employed to buffer the fluids according to an embodiment, i.e., moderate amounts of either a strong base or acid may be added without causing any large change in pH value of the fracturing fluid. In various embodiments, the buffering agent is a combination of a weak acid and a salt of the weak acid; an acid salt with a normal salt; or two acid salts. Examples of suitable buffering agents are sodium carbonate-sodium bicarbonate, sodium bicarbonate, or other like agents. By employing a buffering agent instead of merely a hydroxyl ion producing material, a fracturing fluid is provided which is more stable to a wide range of pH values found in local water supplies and to the influence of acidic materials located in formations and the like. In an exemplary embodiment, the pH control agent is varied between about 0.6 percent and about 40 percent by weight of the polysaccharide employed.

[0119] Some fluid compositions useful in some embodiments of the invention may also include a gas component, produced from any suitable gas that forms an energized fluid

or foam when introduced into an aqueous medium. See, for example, U.S. Pat. No. 3,937,283 (Blauer et al.). Preferably, the gas component comprises a gas selected from nitrogen, air, argon, carbon dioxide, natural gas, and the like, and any mixtures thereof. In an embodiment, the gas component comprises nitrogen or carbon dioxide, in any quality readily available. The gas component may assist in the fracturing and acidizing operation, as well as the well clean-up process. The fluid in one embodiment may contain from about 10% to about 90% or more volume gas component based upon total fluid volume percent, preferably from about 20% to about 80% volume gas component based upon total fluid volume percent, and more preferably from about 30% to about 70% volume gas component based upon total fluid volume percent.

Example 1

[0120] Hydraulic differential pressure was measured in a silica flour pack while pumping potassium chloride brine (2 wt %) at a flow rate of 0.5 ml/min. The silica flour comprised 99.5% quartz, measured by X-ray diffraction. The silica flour consisted of particulates less than 44 microns (325 US mesh) with median diameter of 18.4 microns. The loading comprised 4.9 kg/m² (2.0 lb/ft) in an API recommended conductivity cell between two metal cores under closure stress of 13.8 MPa (2000 psi). FIG. 1 is a schematic drawing of a typical branched network channel 10 formed around an island in the silica flour pack 12 by washout in the conductivity cell. FIG. 2 shows a time-trace of the pressure drop in the silica flour pack and illustrates the slow equilibration rate to steady state. The spikes seen in FIG. 2 are due to washout of silica flour from the pack.

Example 2

[0121] Conductivity of muscovite mica packs formed from mica with a median particle diameter of 120 microns was measured by means of a Chandler Engineering FRT Model 6100 formation response tester in a split-core set-up. The mica was loaded uniformly at 0.5 kg/m (0.1 lb/ft) between two metal cores, which were compressed with closure stresses of 13.8, 20.7, 27.6, and 34.5 MPa (2000, 3000, 4000 and 5000 psi). Potassium chloride brine (2 wt %) was pumped through the cell with flow rates of 0.05, 0.1 and 0.5 ml/min. The steady state conductivity data for the mica packs are presented in Table 1 and shown graphically in FIG. 3. The formation of channels in the mica packs was visually confirmed upon disassembly of the conductivity cell, and it was seen that the higher flow rates resulted in relatively larger channel formation.

TABLE 1

Conductivity of uniform mica packs at 0.5 kg/m.				
Flow Rate, ml/min	Closure Stress, MPa (psi)			
	13.8 (2000)	20.7 (3000)	27.6 (4000)	34.5 (5000)
	Conductivity, mD-m (mD-ft)			
0.50	0.069 (0.225)	0.41 (0.082)	0.25 (0.082)	0.015 (0.048)
0.10	0.036 (0.119)	Not measured	0.010 (0.034)	Not measured
0.05	0.023 (0.074)	0.013 (0.043)	0.008 (0.026)	0.005 (0.015)

Example 3

[0122] Conductivity of muscovite mica packs formed from mica with a median particle diameter of 105 microns was measured in a split-core set-up.

[0123] The mica was loaded uniformly or in pillars at 5 kg/m (0.01 lb/ft) between two Mancos shale cores, which were compressed with closure stresses of 3.4, 6.9, 13.8, 27.6, 41.4 and 55.2 MPa (500, 1000, 2000, 4000, 6000 and 8000 psi). The pillars were arranged in a triangular pattern of 11 pillars in longitudinal rows of 4, 3 and 4 pillars as seen in FIG. 4, or in a 6 by 12 square pattern of 72 pillars, as seen in FIG. 5. Potassium chloride brine (2 wt %) was pumped through the cell with flow rates of 0.05-0.200 ml/min. The steady state conductivity data for the mica packs are presented in Table 2 and shown graphically in FIG. 6. The placement of the mica in the pillar arrangement obtained a relatively higher conductivity than the uniform mica placement. The placement of the mica in the 72-pillar configuration had a higher conductivity relative to the 11-pillar configuration, and both had higher conductivities than the test situation where the mica was distributed uniformly on the core surface.

TABLE 2

Conductivity of uniform and pillared mica packs.					
Mica loading configuration	Closure Stress, MPa (psi)				
	6.9 (1000)	13.8 (2000)	27.6 (4000)	41.4 (6000)	55.2 (8000)
Conductivity, mD-m (mD-ft)					
Uniform, 0.05 kg/m ² ,	0.016 (0.051)	0.005 (0.018)	0.001 (0.004)	less than 0.001	less than 0.001
11-Pillar triangular, 0.05 kg/m ²	1.08 (3.53)	0.276 (0.907)	0.019 (0.062)	0.003 (0.011)	less than 0.001
72-Pillar square, 0.05 kg/m ²	13.1 (42.9)	11.2 (36.6)	5.72 (18.8)	4.12 (13.5)	2.62 (8.60)

Example 4

[0124] An aqueous slurry of 60 g/L of muscovite mica in deionized slickwater was flocculated with a commercial polyacrylamide friction reducer with NaOH to adjust pH to 8.1, 11.9 and 12.5. Visual inspection of the floc indicated that the higher the pH, the larger the floc and the greater the spacing of the floc, indicating that fracture conductivity can be enhanced by flocculation of a fine mesh proppant material. Quantitatively, median particle size was measured by means of an optical microscope. The relative number of mica particles aggregated in the median-sized flocs at the higher pH's was calculated based on the assumptions that each multiparticle floc had a spherical shape and porosity of 0.5. The results are presented in Table 3 below.

TABLE 3

Median particle size and relative number of mica particles in flocs controlled by pH adjustment.			
Sample	Mica slurry	Floc	Floc
pH	8.1	11.9	12.5
Median particle size, mm	0.12	0.74	1.17
No. of particles, n	1	117	463

Example 5

[0125] The procedure of Example 4 was repeated except using 60 g/L silica flour at pH 8.1, 11.9 and 12.5, and the floc characteristics are presented in Table 4. Again, the higher the pH, the larger the floc and larger number of aggregated particles, indicating that fracture conductivity can be enhanced by flocculation of a fine mesh proppant material.

TABLE 4

Median particle size and relative number of silica particles in flocs controlled by pH adjustment.			
Sample	Silica slurry	Floc	Floc
pH	8.1	11.9	12.5
Median particle size, mm	0.018	0.33	0.42
No. of particles, n	1	2880	5950

Example 6

[0126] Settling and flocculation of muscovite mica slurry in slickwater based on cationic polyacrylamide friction reducer

was observed without and with addition of sodium hydroxide to give solution pH of about 8.1 and 12.5, and the relative rate of settling was determined by taking measurements of the height of the dense and dilute phases in a sample bottle after 3, 9 and 19 seconds following caustic addition. In general, the larger the floc that is formed, the faster the settling rate. The results are presented in Table 5, and show that the settling rate and floc size can be controlled by adjusting the pH.

TABLE 5

Settling rates of muscovite mica flocs.				
	pH			
	8.1		12.5	
Elapsed time, seconds	Dilute phase height, mm	Dense phase height, mm	Dilute phase height, mm	Dense phase height, mm
0	0	55	0	55
3	1	54	8	47
9	3	52	17	38
19	14	41	25	30

Example 7

[0127] The particle size of silica powder was determined (Malvern Mastersizer). The values determined were:

[0128] d_{10} =6 micron,

[0129] d_{50} =34 micron, and

[0130] d_{90} =84 micron.

[0131] This silica powder was hydrophobically modified by treatment with an excess of reactive organosilane, using the following procedure. 1 g silica, dried under vacuum, was added to 10 ml trimethylchlorosilane at 20° C. and stirred with a magnetic stirrer for 30 minutes. Then the suspension was filtered and the treated silica was washed on the filter with 50 ml anhydrous toluene and 20 ml anhydrous hexane. After this the treated silica was dried overnight in a vacuum desiccator.

[0132] This hydrophobically modified silica was placed in a bottle containing 10 ml deionised water. As a control, 1 g of unmodified silica was placed in a second bottle, also containing 20 ml deionised water. 1 ml dodecane was added to each bottle, and the bottles were shaken vigorously and then left to stand. The unmodified silica in the control bottle was observed to settle to a layer at the base of the bottle. The hydrophobically modified silica formed a single agglomerated mass in its bottle.

Example 8

[0133] Inorganic substrate, silica gel (Merck Type 9385 Sigma-Aldrich, Cat. No.: 22, 719-6) having particle size between 230 and 400 US mesh (63 micron and 40 micron) and GPC glass beads (100 mesh) was dried under vacuum overnight and given a surface coating of polymer by the following procedure. A quantity of polymer was dissolved in 6 ml dichloromethane (DCM). The polymer/DCM solution was added to 30 g substrate in a small beaker. The mixture was then stirred for approx. 10 min in a fume hood; during this period the DCM evaporated, depositing the polymer as a coating on the surface of the silica. The resulting coated silica was dried at room temperature overnight.

[0134] This polymer coating procedure was carried out using polystyrene (PS) and polymethylmethacrylate (PMMA). The amounts of polymer were 0.15 wt % by weight of the silica (or glass beads). Agglomeration by oil was demonstrated as in the previous example with both polymer-coated granular materials. Polystyrene is more hydrophobic than polymethylmethacrylate and was considered the more suitable of the two materials, producing tighter agglomerates.

[0135] The foregoing disclosure and description of the invention in various embodiments is illustrative and explanatory thereof and it can be readily appreciated by those skilled in the art that various changes in the size, shape and materials, as well as in the details of the illustrated construction or combinations of the elements described herein can be made without departing from the spirit of the invention.

1. A method, comprising:

injecting well treatment fluid comprising fine mesh proppant material into a fracture in a low-permeability subterranean formation thereby forming a proppant pack; and

concurrently or subsequently introducing non-uniformity in the proppant pack to form a conductive flow path for fluid flow through the propped fracture, wherein the

non-uniform proppant pack has a higher conductivity relative to the uniform proppant pack at an identical closure stress

whereby the fine mesh proppant material has a particle size less than 105 microns (140 US mesh).

2. (canceled)

3. The method of claim 1 wherein the fine mesh proppant material is selected from the group consisting of: silica, muscovite, biotite, limestone, Portland cement, talc, kaolin, barite, fly ash, pozzolan, bauxite, alumina, zirconia, titanium oxide, iron oxides, zeolites, graphite, carbon black, aluminosilicates, biopolymer solids, synthetic polymer solids and combinations and mixtures thereof.

4. The method of claim 1 wherein the non-uniformity is introduced by proppant flowback subsequent to injection.

5. The method of claim 1 wherein the non-uniformity is formed by proppant washout.

6. The method of claim 1 wherein the non-uniformity is formed by alternating proppant concentration during the well treatment fluid injection.

7. The method of claim 1 wherein the treatment fluid comprises different sized proppant materials to facilitate the introduction of the non-uniformity.

8. The method of claim 1 wherein the treatment fluid injection comprises a plurality of stages of alternating treatment fluid rheology to introduce the non-uniformity.

9. The method of claim 1 further comprising aggregating the fine mesh proppant material to introduce the non-uniformity.

10. The method of claim 9 wherein the well treatment fluid comprises flocculating agent.

11. The method of claim 9 wherein the well treatment fluid comprises flocculating agent selected from the group consisting of polymers and copolymers of at least one monomer selected from the group consisting of acrylamide, methacrylamide, N-vinylmethylacetamide, N-vinylmethylformamide, vinyl acetate, acrylate esters, methacrylate esters, cyanoacrylate esters, vinyl pyrrolidone and combinations thereof.

12. The method of claim 9 wherein the fine mesh proppant material is hydrophobic and the well treatment fluid comprises a hydrophobic binding liquid to agglomerate the proppant.

13. The method according to claim 12 wherein the fine mesh proppant material is made hydrophobic by a surface coating.

14. The method of claim 1 wherein the fine mesh proppant material is coated with a tackifying agent.

15. The method of claim 1 wherein the well treatment fluid further comprises degradable material selected from the group consisting of substituted and unsubstituted lactide, glycolide, polylactic acid, polyglycolic acid, copolymers of polylactic acid and polyglycolic acid, copolymers of glycolic acid with other hydroxy-, carboxylic acid-, or hydroxycarboxylic acid-containing moieties, copolymers of lactic acid with other hydroxy-, carboxylic acid-, or hydroxycarboxylic acid-containing moieties and mixtures thereof.

16. The method of claim 15 wherein the degradable material comprises fiber.

17. The method of claim 1, wherein proppant in the treatment fluid comprises at least 60 percent by weight, based on the total weight of proppant.

18. The method of claim 1 wherein the well treatment fluid comprises at least about 4.8 g/L (0.04 ppg) of the fine mesh proppant material added.

19. The method of claim 1 wherein the well treatment fluid comprises slickwater.

20. The method of claim 1 wherein the well treatment fluid comprises an effective amount of a friction reducer.

21. The method of claim 1 wherein the formation comprises a permeability less than one millidarcy.

22. The method of claim 1 wherein the non-uniformity comprises a branched network of open channels.

23. A method, comprising:

injecting well treatment fluid comprising fine mesh proppant material and flocculating agent into a fracture in a subterranean formation to form a proppant pack;

aggregating the fine mesh proppant material thereby forming a hydraulically conductive proppant pack in the fracture.

24. The method of claim 23 wherein the aggregation occurs before, during, or subsequent to the injection step, or a combination thereof.

25. The method of claim 23 wherein the treatment fluid comprises flocculant selected from the group consisting of polymers and copolymers of at least one monomer selected from the group consisting of acrylamide, methacrylamide, N-vinylmethylacetamide, N-vinylmethylformamide, vinyl acetate, acrylate esters, methacrylate esters, cyanoacrylate esters, vinyl pyrrolidone and combinations thereof.

26. The method of claim 22 wherein the fine mesh proppant material is hydrophobic and the well treatment fluid comprises a hydrophobic binding liquid to agglomerate the proppant.

27. The method of claim 25 wherein the fine mesh proppant material comprises a hydrophobic surface coating.

28. The method of claim 23 wherein the flocculation facilitates creation of a branching complex network of channels in the proppant pack.

29. The method of claim 23 wherein the flocculation facilitates creation of a branched network of open channels in the proppant pack.

30. The method of claim 23 wherein the formation comprises a permeability less than one millidarcy.

31. A method, comprising:

injecting well treatment fluid comprising proppant material into a fracture in a low-permeability subterranean formation thereby forming a proppant pack, wherein the proppant is a fine mesh material with a median particle size less than 105 microns (140 US mesh); and

concurrently or subsequently introducing non-uniformity in the proppant pack to form a conductive flow path for fluid flow through the propped fracture, wherein the non-uniform proppant pack has a higher conductivity relative to the uniform proppant pack at an identical closure stress.

32. The method of claim 31 wherein at least 60 wt % of the proppant material has a particle size less than 105 microns (140 US mesh).

33. The method of claim 31 wherein at least 90 wt % of the proppant material has a particle size less than 105 microns (140 US mesh).

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