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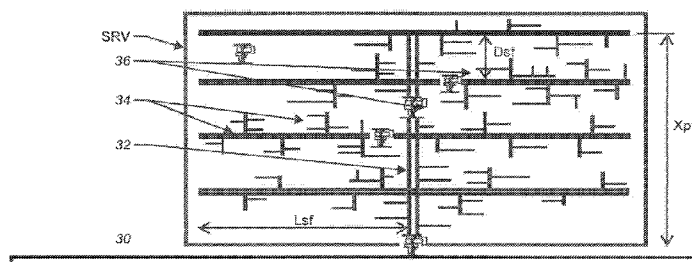


FIG. 4

(57) Abstract: A complex fracture network within a hydrocarbon-bearing subterranean formation is created by first pumping a first fluid into the formation to create or enlarge a primary fracture and then pumping a second fluid into the formation wherein the second fluid contains a viscous material and the first fluid. By diverting the flow of the second flow, a secondary fracture is created having a directional orientation distinct from the directional orientation of the primary fracture.

APPLICATION FOR PATENT

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**TITLE: METHOD OF INCREASING FRACTURE NETWORK
COMPLEXITY AND CONDUCTIVITY**

SPECIFICATION

This application claims the benefit of U.S. patent application 61/809,187, filed on April 5, 2013, herein incorporated by reference.

Field of the Disclosure

[0001] Fracture network complexity within a subterranean formation may be created by pumping a low viscosity fluid into the formation followed by a low viscosity fluid containing independent small masses of viscous material. Stimulated rock volume (SRV) of the formation is increased with the complex fracture network created in the formation.

Background of the Disclosure

[0002] Hydraulic fracturing is widely used to create high-conductivity communication with a large area of a subterranean formation, thereby allowing for an increased rate of oil and gas production. The stimulation process enhances the permeability of the formation in order that entrapped oil or gas may be produced.

[0003] During hydraulic fracturing of ultra-low permeability formations (i.e. such as less than 0.1 md), a fracturing fluid is pumped at high pressures and at high rates into the wellbore penetrating the subterranean formation. During the process, fractures may be created and enlarged that increase the amount of fracture surface area. The efficiency of the process is often measured by stimulated rock volume (SRV) of the formation.

[0004] Once the fracture is initiated, subsequent stages of viscous fluid containing chemical agents, such as proppants, may be pumped into the created fracture. The fracture generally continues to grow during pumping and the proppants remain in the fracture in the form of a permeable "pack" that serves to "prop" the fracture open. Once

the treatment is completed, the fracture closes onto the proppants. The fracturing fluid ultimately causes an increase in the leak-off rate of the fluid through the faces of fractures which improves the ability of the proppant to pack within the fracture. The proppants maintain the fracture open, for the purpose of providing a highly conductive pathway for hydrocarbons and/or other formation fluids to flow into the wellbore.

[0005] Typically, the treatment design of a hydraulic fracturing operation requires the fracturing fluid to reach maximum viscosity as it enters the fracture. The viscosity of the fluid affects fracture length and width. The viscosity of most fracturing fluids may be attributable to the presence of a viscosifying agent, such as a viscoelastic surfactant or a viscosifying polymer. After the viscosity of the fluid has been reduced, complete removal of the polymer is often difficult, often times resulting in residual polymer being left on the face of the formation and within the proppant pack. This causes clogging of the pores of the formation and proppant pack. Hydrocarbons may therefore be prevented from flowing freely through and from the formation.

[0006] The use of non-polymeric treatment fluids, such as those containing viscoelastic surfactants, has increased in recent years since such fluids typically exhibit the ability to transport proppant at lower viscosities than polymer-based treatment fluids. In addition, the amount of friction between the surfactant-based treatment fluid and the surfaces contacted by the fluid is often reduced. Further, since such fluids do not contain polymers, use of internal breakers degrade viscous VES-micelles into non-viscous spherical-micelles and the clean breaking fluid is typically not obstructed as it passes through the pore throats of the formation and proppant pack.

[0007] Slickwater fluids typically do not contain a viscoelastic surfactant or viscosifying polymer but do contain a sufficient amount of a friction reducing agent to minimize tubular friction pressures. Typically, the presence of the friction reduction agent in slickwater does not increase the viscosity of the fluid by more than 1 to 2 centipoise (cP). Slickwater fluids may be pumped down the wellbore as fast as 100 bbl/min. to fracture the low permeability formation. Without using slickwater the top speed of pumping is around 60 bbl/min.

[0008] Slickwater fracturing operations typically proceed by the continuous injection of slickwater into the wellbore. In some shale formations, an excessively long primary

fracture often results along the minimum stress orientation. Typically, two wings of the fracture extend away from the wellbore in opposing directions according to the natural stresses within the formation. Typically, pumping of additional fracturing fluid into the wellbore simply extends the planar fracture. In most instances, primary fractures dominate and secondary fractures are limited. Fracturing treatments which create predominately long planar fractures are characterized by a low surface area, i.e., low SRV. Production of hydrocarbons from the fracturing network created by such treatments is limited by the low SRV.

[0009] Slickwater fracturing more commonly in shale formations create complex fracture networks near the wellbore and are generally considered to be inefficient in the opening or creation of complex network of fractures farther away from the wellbore. Lately, slickwater fracturing operations have been seen to be successful in producing hydrocarbons from shale. However, the secondary fractures created by the operation are near to the wellbore where the surface area is increased. While SRV is increased in slickwater fracturing, production is high only initially and then drops rapidly to a lower sustained production since there is little access to hydrocarbons far field from the wellbore.

[00010] Like slickwater fracturing, conventional fracturing operations typically render an undesirably lengthy primary fracture. While a greater number of secondary fractures may be created farther from the wellbore using viscous fluids versus slickwater, fluid inefficiency, principally exhibited by a reduced number of secondary fractures generated near the wellbore, is common in conventional hydraulic fracturing operations.

[00011] Recently, attention has been directed to alternatives for increasing the productivity of hydrocarbons far field from the wellbore as well as near wellbore. Particular attention has been focused on increasing the productivity of low permeability formations. For instance, methods have been tailored to the stimulation of discrete intervals along the horizontal wellbore resulting in perforation clusters. While the SRV of the formation is increased by such methods, production areas between the clusters are often not affected by the operation. This decreases the efficiency of the stimulation operation. Methods of increasing the SRV by increasing the distribution of the area subjected to fracturing have therefore been sought.

[00012] It should be understood that the above-described discussion is provided for illustrative purposes only and is not intended to limit the scope or subject matter of the appended claims or those of any related patent application or patent. Thus, none of the appended claims or claims of any related application or patent should be limited by the above discussion or construed to address, include or exclude each or any of the above-cited features or disadvantages merely because of the mention thereof herein.

[00013] Accordingly, there exists a need for improved compositions, systems, apparatus and methods useful for increasing the productivity of hydrocarbons far field from the wellbore as well as near wellbore especially in low permeability formations equipped with having one or more of the attributes or capabilities described or shown in, or as may be apparent from, the other portions of this patent.

Summary of the Disclosure

[00014] In an embodiment of the disclosure, a method of fracturing a hydrocarbon-bearing subterranean formation is provided in which the first stage comprises:

- (a) pumping a first fluid into the formation at a pressure sufficient to create or enlarge a primary fracture;
- (b) pumping a second fluid into the formation, wherein the second fluid comprises the first fluid and a viscous material;
- (c) creating or enlarging at least one secondary fracture having a directional orientation distinct from the directional orientation of the primary fracture by diverting the flow of the second fluid; and
- (d) forming a complex fracture network by creating multiple fractures in the formation originating from the at least one secondary fracture.

[00015] In another embodiment, a method of fracturing a hydrocarbon-bearing subterranean formation is provided in which the first stage comprises:

- (A) pumping a first fluid of low viscosity into the formation at a pressure sufficient to create or enlarge a primary fracture; and
- (B) forming a complex fracture network comprising
 - (a) at least one secondary fracture having a directional orientation distinct from the directional orientation of the primary fracture; and

- (b) a multiple of fractures originating from the at least one secondary fracture and having a directional orientation distinct from the direction orientation of the at least one secondary fracture

wherein the complex fracture network is formed by pumping a second fluid into the formation, wherein the second fluid comprises (i) the first fluid of low viscosity and (ii) a plurality of discrete bodies having a viscosity greater than the viscosity of the first fluid.

[00016] In another embodiment of the disclosure, a method of hydraulically fracturing a hydrocarbon-bearing subterranean formation is provided in which a first stage comprises:

- (a) pumping a first fluid of low viscosity into the formation at a pressure sufficient to create or enlarge a primary fracture;

- (b) pumping a second fluid into the formation, wherein the second fluid is prepared by adding to the first fluid a plurality of discrete bodies having a viscosity greater than the viscosity of the first fluid;

- (c) creating or enlarging at least one secondary fracture having a directional orientation distinct from the directional orientation of the primary fracture by diverting the flow of the second fluid; and

- (d) forming a complex fracture network through the addition of a diverting fluid into the formation and creating multiple fractures in the formation originating from the at least one secondary fracture wherein the diverting fluid is prepared by adding to the first fluid a plurality of discrete bodies having a viscosity greater than the viscosity of the first fluid and wherein the multiple fractures are created by the action of the plurality of discrete bodies of viscous material in the diverting fluid.

[00017] In still another embodiment of the disclosure, a method of fracturing a hydrocarbon-bearing subterranean formation is provided in order to create a complex fracture network, wherein in a first stage, a first fluid and a second fluid are pumped into the formation, wherein the at least one second fluid is comprised of a viscous material and the first fluid, wherein:

- (a) a primary fracture is created or enlarged by pumping into the formation the first fluid;

- (b) at least one secondary fracture perpendicular and/or orthogonal to the primary fracture is created by diverting the flow of the at least one second fluid; and
- (c) a complex fracture network comprising a series of fractures is created by continuously diverting the flow of the at least one second fluid through the formation and further wherein either:
 - (i) the surface area ratio (S_r), defined by S_{cf}/S_{pf} wherein S_{cf} is the surface area of the complex fracture network and S_{pf} is the surface area over the primary fracture, is greater when the first fluid and second fluid are pumped into the formation versus when only the first fluid is pumped into the formation; or
 - (ii) the conductivity ratio (C_r) defined by C_{cf}/C_{pf} , wherein C_{cf} is the conductivity of the complex fracture network and C_{pf} is the conductivity of the planar fracture divided by 1000 is greater when the first fluid and the at least one second fluid are pumped into the formation versus when only the first fluid is pumped into the formation.

[00018] Accordingly, the present disclosure includes features and advantages which are believed to enable it to advance methods of fracturing. Characteristics and advantages of the present disclosure described above and additional features and benefits will be readily apparent to those skilled in the art upon consideration of the following detailed description of various embodiments and referring to the accompanying drawings.

Brief Description of the Drawings

[00019] The following figures are part of the present specification, included to demonstrate certain aspects of various embodiments of this disclosure and referenced in the detailed description herein:

[00020] FIGS. 1a, 1b, 1c and 1d are schematic illustrations of how discrete bodies of higher viscosity material described herein may vary;

[00021] FIGS. 2a, 2b and 2c are schematic illustrations of discrete bodies of higher viscosity material having different materials contained therein;

[00022] FIGS. 3a and 3b are schematic illustrations of how discrete bodies of higher viscosity material as described herein may be sized and formulated to generate viscosity under wall shear conditions in narrow fractures; and

[00023] FIG. 4 is a schematic illustration of possible choke points in within a complex fracture network.

Detailed Description of Embodiments

[00024] Characteristics and advantages of the present disclosure and additional features and benefits will be readily apparent to those skilled in the art upon consideration of the following detailed description of exemplary embodiments of the present disclosure and referring to the accompanying figures. It should be understood that the description herein and appended drawings, being of example embodiments, are not intended to limit the claims of this patent or any patent or patent application claiming priority hereto. On the contrary, the intention is to cover all modifications, equivalents and alternatives falling within the spirit and scope of the claims. Many changes may be made to the particular embodiments and details disclosed herein without departing from such spirit and scope.

[00025] In showing and describing embodiments in the appended figures, common or similar elements may be referenced with like or identical reference numerals or are apparent from the figures and/or the description herein. The figures are not necessarily to scale and certain features and certain views of the figures may be shown exaggerated in scale or in schematic in the interest of clarity and conciseness.

[00026] As used herein and throughout various portions (and headings) of this patent application, the terms "disclosure", "present disclosure" and variations thereof are not intended to mean every possible embodiment encompassed by this disclosure or any particular claim(s). Thus, the subject matter of each such reference should not be considered as necessary for, or part of, every embodiment hereof or of any particular claim(s) merely because of such reference.

[00027] Certain terms are used herein and in the appended claims to refer to particular elements and materials. As one skilled in the art will appreciate, different persons may refer to an element and material by different names. This document does not intend to

distinguish between elements or materials that differ in name. Also, the terms "including" and "comprising" are used herein and in the appended claims in an open-ended fashion, and thus should be interpreted to mean "including, but not limited to" Further, reference herein and in the appended claims to elements and components and aspects in a singular tense does not necessarily limit the present disclosure or appended claims to only one such component, materials or aspect, but should be interpreted generally to mean one or more, as may be suitable and desirable in each particular instance.

[00028] The methods described herein may be used in the treatment of conventional rock formations such as carbonate formations (like limestone, chalk and dolomite), sandstone or siliceous substrate minerals, such as quartz, clay, shale, silt, chert, zeolite, or a combination thereof. The methods have particular applicability in the treatment of unconventional hydrocarbon reservoir formations such as low permeability or "tight" formations, such as shale, tight sandstone and coal bed methane wells.

[00029] The methods described herein are especially effective with those subterranean reservoirs having a permeability less than or equal to 1.0 mD and most especially those subterranean reservoirs having a permeability less than or equal to 0.1 mD.

[00030] The disclosed method may consist of one or more stages. In one embodiment, a network of fractures may be created at near-wellbore and far-wellbore locations in a first stage.

[00031] The first stage comprises the pumping of a low viscosity fluid into the formation at a pressure which is sufficient to create or enlarge a primary fracture. This low viscosity fluid may be referred to as the "first fluid" of the first stage of the fracturing operation. The volume of first fluid pumped into the formation is selected in order to provide the desired length of the primary fracture. Thus, for instance, if the primary fracture is desired to be limited to 500 feet, the volume of low viscosity fluid pumped into the wellbore may be selected to provide the desired length of a 500 foot primary fracture.

[00032] The low viscosity fluid may be slickwater or a brine.

[00033] The low viscosity fluid may contain a friction reduction agent. Suitable friction reduction agents include polyacrylamides, polyacrylates, as well as any of the

viscoelastic surfactants described herein. When present, the amount of friction reduction agent in the first fluid is typically between from about 0.5 gallons per thousand (gpt) to 2 gpt.

[00034] After the primary fracture is created (or a primary fracture within the reservoir is enlarged), one or more secondary fractures are created within the formation. The secondary fracture typically extends from the primary fracture and has a directional orientation which is distinct from the directional orientation of the primary fracture.

[00035] The secondary fracture(s) are created by pumping into the formation a second fluid. The second fluid comprises the first fluid along with a viscous material. The viscosity of the second fluid is substantially the same as the viscosity of the first fluid. As such, the presence of the viscous material in the fluid does not substantially affect the viscosity of the second fluid. Thus, during fracturing, at the surface and within the wellbore the second fluid exhibits fluid properties like the low viscosity (first) fluid.

[00036] Typically, a low loading of the viscous material is used in the second fluid in order that the viscosity of the second fluid and first fluid may be substantially the same. The low loading of the viscous material also minimizes residue and conductivity damage. Representative concentrations of the viscous material in the relatively low viscosity (first) fluid may range from about 0.1 vol% to about 20 vol%; alternatively range from about 0.2% vol% to about 5 vol%; alternatively range from about 0.25 vol% to about 2 vol%. Use of a viscous material in the low viscous fluid provides the second fluid with the initial properties of the low viscosity first fluid and higher viscosity properties once it is in select sections of the primary and secondary fractures.

[00037] In one non-limiting embodiment, the viscous material consists of discontinuous masses or discrete bodies. Such discrete bodies may be prepared by the use of an extruder or die having a sizing cutter adapted to divide the viscous material into discrete bodies of a predetermined size such as that set forth in the U.S. patent application entitled "Method to Generate Diversion and Distribution For Unconventional Fracturing in Shale" by inventor James B. Crews, filed on an even date of the present application, and assigned U.S. patent application serial no. 14/225,526 filed on March 26, 2014 and which is incorporated herein by reference.

[00038] The size of the viscous material will typically vary depending on the width characteristic of the hydraulic fractures created within lower permeability reservoirs. For instance, the viscous material may have an average particle size from about 500 nm to about 50 cm, in one non-limiting embodiment 500 nm to about 30 mm, alternatively from about 1 μ m to about 4 mm, and in another non-limiting embodiment about 10 μ m to about 1 mm.

[00039] During pumping, the viscous material effectively retains its size and shape within the second fluid and appears as discrete tiny masses with near zero shear rate viscosity in the low viscosity fluid. The tiny high viscosity material in the second fluid, in one non-limiting embodiment, is thus highly elastic and deformable and resists fluid-shear-induced fragmentation during pumping. Depending on the size of the viscous material, the second fluid may behave like the first fluid as it flows into and through the initial portion of the primary fracture. Once the second fluid is within a section of the primary fracture which has a width similar to or smaller than the viscous material, such as the primary fracture width 500' from the wellbore, the second fluid will change its flow properties (i.e. during viscous material interaction with the fracture walls) and be diverted from the primary fracture. Initiation and extension of one or more secondary fractures can then occur off of the primary fracture, preferably initially far-field. Changes to any of the size, shape, viscosity, or other parameters of the viscous material as well as a change in the pumping rate of the second fluid may allow flow of the second fluid into secondary fractures. Then, like within the primary fracture, when the high viscosity masses encounter fracture widths similar to or less than the size of the viscous material, due to the parameters of the viscous material and interaction with the fracture walls the flow properties of the second fluid will change and flow may be diverted from one or more of the secondary fractures.

[00040] Pumping of the second fluid into the formation may be suspended for a sufficient time to allow the fluid to be diverted away from the primary fracture.

[00041] By controlling the viscosity and shear sensitivity of the viscous material, frictional interaction of the viscous material with the walls of narrow fractures may cause the second fluid to transition from a low viscosity fluid flow (brine or slickwater) to a combination of low viscosity fluid flow (brine or slickwater) and discrete viscous

material having fracture wall interaction properties flow (i.e. dual-fluid; brine fluid having little interaction with fracture walls and discrete viscous fluid masses with viscous interaction with fracture walls). Once the second fluid interacts with narrow hydraulic fractures the flow induces performance properties and processes such as a) path of least resistance flow deviation; b) lodging of viscous material in the fracture that reduces but does not totally eliminate treatment fluid flow; (c) total fluid diversion; (d) in situ wall-shear induced fluid viscosity generation (i.e. less elastic and more deformable discrete viscous masses that shear thins in viscosity into a somewhat flowable, discrete fluid mass in the narrow fracture and thereby becoming flattened, like a pancake, and take up greater area in the narrow fracture); and (e) distribution of delayed released treatment additives can be engineered (once viscous masses internally break in viscosity). Most of these processes (i.e., partial diversion, path of least resistance flow alteration, complete flow diversion, etc.) will induce increased hydraulic fluid pressure (i.e. within the fracture where interactions are occurring). The increase in fluid pressure in the fracture may: a) reduce flow of the second fluid in the fracture; b) increase fracture width (build-up of fluid pressure in fracture does not divert fluid instantly but may open fracture wider), c) alter fracture extension (as fracture width builds fracture length can grow), and d) eventually the build-up of pressure in the fracture will overcome the anisotropy rock stress to initiate and propagate new fracture(s). Fracture network complexity therefore results.

[00042] Successive generated fractures may be created as an inherent characteristic of use of the second fluid as diverting fluid. Such additional fractures may then be created which originate from the secondary fracture(s). For instance, a tertiary fracture may be created by pumping the second fluid at a pressure which is sufficient for the fluid to be diverted away from the secondary fracture. A quaternary fracture may be created by pumping the second fluid at a pressure which is sufficient for the fluid to be diverted away from the tertiary fracture, and so on. Changes to the size, shape, viscosity and the like of the discrete tiny masses, and the type of interaction they exhibit with the walls of the fracture, play an important function in ability to induce diversion of the second fluid and the number of diversions within successive fractures. The tertiary, quaternary, quintary fractures and so on all originate from the creation of the secondary fractures.

Each of the fractures originating from secondary fractures typically has a directional orientation distinct from the direction orientation of the fracture from which it extends. Thus, a tertiary fracture originating from a secondary fracture typically has a directional orientation distinct from the direction orientation of the secondary fracture; the quaternary fracture stemming from the tertiary fracture (originating from the secondary fracture) typically has a directional orientation distinct from the tertiary fracture; the quintary fracture stemming from the quaternary fracture (originating from the secondary fracture) has a directional orientation distinct from the quaternary fracture and so on.

[00043] Such additional fractures will be referred to herein as the “successive fracture” and the “penultimate fracture” to refer to the latter and next to latter fractures, respectively, wherein the fracture created from a successive stage has a directional orientation distinct from that of the fracture created from a penultimate stage. For example, where a tertiary fracture is created which extends from a secondary fracture, the tertiary fracture may be referred to as the “successive fracture” and the second fracture (extending from the primary fracture) as the “penultimate fracture.” Where a quaternary fracture is created, the quaternary fracture stage may be referred to as the “successive fracture” and the tertiary fracture may be referred to as the “penultimate fracture,” etc. Where a fracturing operation consists of the creation of multiple fractures, the fracture created from the pumping of a second fluid shall be referred to as a “secondary fracture”.

[00044] In some cases, the second fluid and the diverting fluid used in the creation or enlargement of successive and penultimate fractures may be the same. The fluids may differ by varying the factors which are described herein. However, for simplicity, the fluid pumped into the formation to create such successive fractures and penultimate fractures shall only be referred to as the “second fluid” since the fluid will be comprised of the low viscosity (first) fluid and the viscous material. Certain characteristics of the viscous material may be optimized in order to create the multiple fractures defining the complex fracture network. In other words, the first stage of the disclosed method designed to render the complex fracture network may be monitored and tailored such that the fluid creating the fracture(s) is targeted to maximize the amount of fluid used in order to render the desired fracture.

[00045] As an example, during the first stage, the viscous material within the second fluid may be varied, depending on the desired fracture length, width and level of conductivity, by 1) viscosity; 2) low shear rate elasticity; 3) size; 4) shape; 5) combination of sizes and/or shapes; 6) concentration to first fluid; 7) composition and density of the first fluid; and 8) inclusion of treatment materials within the viscous material (such as proppant, cleanup agent, clay control agent, breaker, tracer, and the like).

[00046] Thus, during the first stage where the complex fracture network is created, more than one viscous material may vary in viscosity, composition, density, content, size, shape, concentration in the brine, and the like, for providing more versatility or wider range of fracture interaction. In one non-limiting example, larger size, higher concentration and more viscous material may be used to produce a second fluid for improving treatment fluid diversion from the primary fracture, where a second viscous material could produce a second fluid better suited for fluid diversion within narrow secondary fractures, and a third viscous material could be used to produce a second fluid better suited (*i.e.* smaller in size, less elastic and more deformable, and contain smaller proppant) for creating a successive fracture(s).

[00047] Control of conditions to create the complex fracture network such as varying the size of the viscous material, the shape of the viscous material and/or the concentration of the viscous material within the second fluid may be effectuated by use of an extruder or dye on the fly. Such extruders and dies include those known in the art including those described in the patent application entitled "Method to Generate Diversion and Distribution For Unconventional Fracturing in Shale" by James B. Crews, filed on an even date of the present application. Thus, the method disclosed herein may provide for a more efficient use of on-the-fly equipment and materials.

[00048] The multiple fractures created by diversion of the second fluid through the formation form a complex fracture network exhibiting an increase in SRV.

[00049] Further in a non-limiting embodiment, the surface area ratio (S_r), defined by S_{cf}/S_{pf} wherein S_{cf} is the surface area of the complex fracture network and S_{pf} is the surface area over the primary fracture, has been noted to be greater when the first fluid

and second fluid are pumped into the formation versus when only the first fluid is pumped into the formation.

[00050] The viscous material comprising the second fluid may be a hydratable polymer such as, for example, one or more polysaccharides capable of forming linear or crosslinked gels. These include galactomannan gums, guar, derivatized guar, cellulose and cellulose derivatives, starch, starch derivatives, xanthan, derivatized xanthan and mixtures thereof.

[00051] Specific examples include, but are not limited to, guar gum, guar gum derivative, locust bean gum, welan gum, karaya gum, xanthan gum, scleroglucan, diutan, cellulose and cellulose derivatives, etc. More typical polymers or gelling agents include guar gum, hydroxypropyl guar (HPG), carboxymethyl hydroxypropyl guar (CMHPG), hydroxyethyl cellulose (HEC), carboxymethyl hydroxyethyl cellulose (CMHEC), carboxymethyl cellulose (CMC), dialkyl carboxymethyl cellulose, etc. Other examples of polymers include, but are not limited to, polyacrylamides, polyvinylacetates, copolymers, terpolymers, phosphomannans, scleroglucans and dextrans.

[00052] The fluid containing the viscosifying polymer may further include a crosslinking agent.

[00053] Any crosslinking agent suitable for crosslinking the hydratable polymer may be employed. Examples of suitable crosslinking agents include metal ions such as aluminum, antimony, zirconium and titanium-containing compounds, including organotitanates. Examples of suitable crosslinkers may also be found in U.S. Pat. No. 5,201,370; U.S. Pat. No. 5,514,309, U.S. Pat. No. 5,247,995, U.S. Pat. No. 5,562,160, and U.S. Patent No. 6,110,875, incorporated herein by reference. Further examples of crosslinking agents are borate-based crosslinkers such as organo-borates, mono-borates, poly-borates, mineral borates, etc. Organic crosslinkers known to the art may also be utilized.

[00054] In an embodiment, the viscosifying agent is non-polymeric such as a viscoelastic surfactant. The viscoelastic surfactant suitable for use as the viscosifying agent may be micellular, such as worm-like micelles, surfactant aggregations or vesicles, lamellar micelles, etc. Such micelles include those set forth in U.S. Patent No. 6,491,099; 6,435,277; 6,410,489; and 7,115,546.

[00055] Suitable viscoelastic surfactants include cationic, amphoteric and anionic surfactants. Suitable cationic surfactants include those having only a single cationic group which may be of any charge state (e.g., the cationic group may have a single positive charge or two positive charges). The cationic group preferably is a quaternary ammonium moiety (such as a linear quaternary amine, a benzyl quaternary amine or a quaternary ammonium halide), a quaternary sulfonium moiety or a quaternary phosphonium moiety or mixtures thereof. Preferably the quaternary group is quaternary ammonium halide or quaternary amine, most preferably, the cationic group is quaternary ammonium chloride or a quaternary ammonium bromide.

[00056] The amphoteric surfactant preferably contains a single cationic group. The cationic group of the amphoteric surfactant is preferably the same as those listed in the paragraph above. The amphoteric surfactant may be one or more of glycines, amphoteric surfactants, propionates, betaines, amine oxides, and mixtures thereof. Preferably, the amphoteric surfactant is a glycine, amine oxide or a betaine and, most preferably, the amphoteric surfactant is a linear glycine, alkylaminopropyl amine oxide, or a linear betaine.

[00057] The cationic or amphoteric surfactant has a hydrophobic tail (which may be saturated or unsaturated). Preferably the tail has a carbon chain length from about C12-C18. Preferably, the hydrophobic tail is obtained from a natural oil from plants, such as one or more of coconut oil, soybean oil, rapeseed oil and palm oil. Exemplary of surfactants include N,N,N trimethyl-1-octadecammonium chloride; N,N,N trimethyl-1-hexadecammonium chloride; and N,N,N trimethyl-1-soyammmonium chloride, and mixtures thereof.

[00058] Exemplary of anionic surfactants are sulfonates, phosphonates, ethoxysulfates and mixtures thereof. Preferably the anionic surfactant is a sulfonate. Most preferably the anionic surfactant is a sulfonate such as sodium xylene sulfonate and sodium naphthalene sulfonate.

[00059] In one embodiment, a mixture of surfactants are utilized to produce a mixture of (1) a first surfactant that is one or more cationic and/or amphoteric surfactants set forth above and (2) at least one anionic surfactant set forth above.

[00060] A mixture of any of the aforementioned viscous materials may also be used.

[00061] While the viscosity of the second fluid and first fluid may be substantially the same, the viscous material is at least 1,000 times more viscous than the first fluid, and typically is more than 100,000 times more viscous than the first fluid at 0.01 sec^{-1} shear rate at 80°F (27°C). The ratio in viscosity (measured at 0.01 sec^{-1} and 80°F (27°C)), V_r , of the viscous material to the first fluid may be designed to achieve the fracturing and production purposes of the methods described herein. In one non-limiting embodiment, for example, V_r is 100 or greater, in one non-limiting embodiment 1000 or greater, alternatively is 10,000 or greater, and in a different non-limiting embodiment is 100,000 or greater.

[00062] The integrity of the viscous material to retain its size and shape during shear when being pumped downhole may be dependent on the viscosity, size, shape, density and other properties of the viscous material. While the viscous material may be of larger sizes fluid diversion in fairly wide fracture widths; small sizes are preferred within very narrow fracture widths.

[00063] Shown in FIGS. 1a, 1b, 1c and 1d are schematic illustrations of the discrete bodies of viscous material which may vary one to the other. FIG. 1a shows that discrete bodies may have different average particle sizes. FIG. 1b schematically illustrates that discrete bodies may have different viscosities, where the heavier the shading, the greater the viscosity. FIG. 1c schematically illustrates how discrete bodies may be of different shapes, for instance a spherical shape shown at the top; to bent round rods or pins shapes, second; to straighter round rods or pins shapes, third; and long-aspect rectangles (for instance, a "french fry"-like shape), or discs of varying thickness (for instance, flattened spheres or egg-shapes) shapes, fourth. In some cases, some shapes may work better than others at holding their shape in different applications, or may function better than others for certain purposes, e.g. distributing proppants or enclosed additives. FIG. 1d schematically illustrates how different shapes may contain various other materials. It will be appreciated that these various characteristics may be combined with each other so that discrete bodies may be customized for a particular application.

[00064] The first fluid or second fluid may also contain other conventional additives common to the well service industry such as surfactants, biocides, gelling agents, cross-linking agents, curable resins, hardening agents, solvents, foaming agents, demulsifiers,

buffers, clay stabilizers, acids, or mixtures thereof. Other additives may include, but are not necessarily limited to, piezoelectric particles, metal particles, metal complexes, metal salts, fines control agents, solid acids, solid high pH buffers, salts, chelants, oxidizers, plant and fish oils, mineral oils, shape memory polymers, fibers, glass spheres, encapsulations and combinations thereof.

[00065] In an embodiment, illustrated in FIG. 2a, discrete bodies 10 may include spherical encapsulant 12 containing a treatment agent. FIG. 2b illustrates discrete body 14 containing a dispersed or soluble treatment agent 16. The treatment agent may include, but not be limited to, biocides, tracers, proppants, self-assembling nanocoating agents for modifying fracture face properties, surfactants, scale inhibitors, asphaltene inhibitors, hydrogen sulfide scavengers, polymer breakers, VES breakers, microemulsions to improve treatment fluid cleanup, other treatment fluid cleanup agents, fines migration control additives, fines migration control nanoparticles, fracture imaging materials (diagnostic agents that interact with signals and sensors), delayed release additives and combinations thereof. For instance, one type of nanocoating agent may be surface-modifying agents to introduce hydrophobicity and/or oleophobicity to the fracture surfaces. In a preferred though non-limiting embodiment, the second fluid may contain an internal viscosity breaker to enable the viscous material to break at targeted locations within the formation under downhole conditions. In an embodiment, spherical encapsulant 12 as well as treatment agent 16 may be blended into the viscous material in the device reservoir prior to being extruded through a conduit into discrete bodies 10.

[00066] The second fluid may further contain proppant. FIG. 2c illustrates discrete body 18 containing dispersed proppant particles 20.

[00067] The viscous materials disclosed herein are effective in promoting distribution of proppants in complex fracture networks. Particularly by wedging or elongating and/or flattening within the complex fractures to lodge the proppant particles in place, such as small unconventional proppants designed to create transitional nanodarcy to microdarcy to millidarcy conductivity in the narrow secondary, tertiary, quaternary, and the like complex fractures that typically remain unpropped due to the size and use of only conventional proppants like 20/40 and 30/70 mesh sand and ceramic proppants.

[00068] In an embodiment, the proppant having an apparent specific gravity (ASG) less than or equal to 2.25, more preferably less than or equal to 2.0, even more preferably less than or equal to 1.75, most preferably less than or equal to 1.25 and often less than or equal to 1.05.

[00069] The proppant may further be a resin coated ceramic proppant or a synthetic organic particle such as nylon pellets, ceramics. Suitable proppants further include those set forth in U.S. Patent Publication No. 2007/0209795 and U.S. Patent Publication No. 2007/0209794, herein incorporated by reference. The proppant may further be a plastic or a plastic composite such as a thermoplastic or thermoplastic composite or a resin or an aggregate containing a binder. Other suitable relatively lightweight proppants are those particulates disclosed in U.S. Patent Nos. 6,364,018, 6,330,916 and 6,059,034, all of which are herein incorporated by reference. These may be exemplified by ground or crushed shells of nuts (pecan, almond, ivory nut, brazil nut, macadamia nut, etc); ground or crushed seed shells (including fruit pits) of seeds of fruits such as plum, 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 particalization. Preferred are ground or crushed walnut shell materials coated with a resin to substantially protect and water proof the shell. Such materials may have an ASG of from about 1.25 to about 1.35. Further, lightweight particulate may be a selectively configured porous particulate, as set forth, illustrated and defined in U.S. Patent No. 7,426,961, herein incorporated by reference.

[00070] The proppants for use in the second fluid most preferably have an ASG between from about 0.9 to about 1.8, and most preferably from about 1.0 to about 1.2. The smaller size will depend on the complex fracture widths for the particular lithology that is hydraulically fracture treated. In some cases, such proppants will be less than 1 mm but larger than 10 microns in size.

[00071] Conventional proppants, such as sand, quartz, ceramics, silica, glass and bauxite, may be used and are more typically used for wider complex fractures and planar fracture to provide millidarcy to macrodarcy fracture conductivities.

[00072] Conductivity of the primary fracture may be enhanced by pumping into the formation a second stage. The viscosity of the second stage fluid(s) is generally greater than the viscosity of first fluid or second fluid. Typically, the viscosity of the second stage fluid(s) is greater than 10 cps at 80°F at 100 sec⁻¹. In some circumstances, the fluid of the second stage may be the same as the first fluid of the first stage.

[00073] The second stage fluid(s) may contain any of the viscosifying polymers or viscoelastic surfactants referenced in the paragraphs above. Thus, the second stage fluid(s) may contain of the aforementioned linear polymers, crosslinked polymers, viscoelastic surfactants, as well as combinations thereof.

[00074] Further, the second stage fluid(s) may contain a proppant. Suitable proppant may include any of the proppants referenced in the paragraphs above include conventional heavier proppants such as sand, bauxite, glass, etc. as well as lightweight proppants having an ASG less than 2.45.

[00075] In some embodiments, selection of proppant is designed in order to form a partial monolayer of proppant within created or enlarged fracture(s).

[00076] Fracture conductivity may be enhanced with any created or enlarged fracture(s) by varying the size of the proppant within the first fluid or second fluid; the apparent specific gravity of the proppant within the first fluid or second fluid; or the shape of the proppant within the first fluid or second fluid.

[00077] Depending on the formation being treated, all or part of the second stage fluid may be pumped into the formation prior to pumping of the first fluid, prior or after pumping of the first fluid but prior to pumping of the second fluid of the first stage.

[00078] The method of the disclosure further helps in the creation of a transition of propped fracture conductivity from the fracture tip to the wellbore, starting with nanodarcy permeabilities at the fracture tips, to microdarcy permeabilities in the complex, secondary fractures to millidarcy to darcy permeabilities near the primary fracture, then to darcy to macrodarcy permeabilities within the primary propped fracture. Such transitional fracture conductivity and the control of conductivity within the complex fracture network may be attributable to the presence of the viscous material in the pumped fluid coupled with proppant placement and distribution within the fractures.

[00079] In non-limiting embodiment, the conductivity ratio (Cr) defined by C_{cf}/C_{pf} , wherein C_{cf} is the conductivity of the complex fracture network and C_{pf} is the conductivity of the planar fracture divided by 1000, has been noted to be greater when the first fluid and the at least one second fluid are pumped into the formation versus when only the first fluid is pumped into the formation.

[00080] Referring to FIG. 3a viscous material 20 within second fluid 18 is shown entering fracture 22. As the width of the fracture 22 narrows viscous material 20 interacts with the fracture walls. Viscous material 20 is illustrated as masses of discrete bodies. FIG. 3b illustrates examples of specific type of discrete bodies 20a that may more easily deform in the narrow fracture region of fracture 22. The deformation of bodies 20a are by interaction with the walls of fracture 22, where the shear force relatively thins the viscosity of bodies 20a. The more they shear thin and deform the more fluid-like bodies 20a become. Depending on their initial viscosity and fracture wall-induced shear thinning properties, bodies 20a become discrete viscous fluid bodies 26 that occupy greater fracture surface area within the narrow region of fracture 22, as represented by viscous deformed masses 26. Viscous deformed masses 26 represent the adaptive properties of high viscosity bodies 20a, where they can be transformed or modified *in situ* into discrete viscous fracturing fluid masses.

[00081] The ability to transform viscous material 20a into viscous fluid masses 26 promotes unique hydraulic pressure with the first fluid within the fracture 22, generating a combined second fluid hydraulic pressure medium to slow and eventually prevent further fracture growth and the restrictive flow pressure will initiate a new fracture and create fluid diversion. Additionally, viscous fluid masses 26 can occupy greater fracture surface area the deeper masses 26 penetrate. When the masses of the discrete bodies 20a contain proppant and create greater fracture surface area masses 26 they will thus create channel-type conductivity, as illustrated in FIG. 3b.

[00082] As further schematically illustrated in FIG. 5b, viscous gel bodies 20a generate viscosity only in very narrow fractures. Narrow fractures may be defined as less than 1 mm wide, and may range from about 1 μ m (micrometer) up to 1 mm. The typical range where viscous gel bodies 20a generate viscosity and form high fracture surface area fluid masses 26 will be from 0.5 mm to 0.02 mm, in one non-limiting example. For

relatively wider fracture widths, discrete bodies 26 will retain their shapes as shown in the left side of FIG. 3b. However, for very narrow fracture widths, as at the bottom of fracture 22 in FIG. 3a, and the right side of FIG. 3b, discrete bodies 20a may form wall-shear deformed discrete fluid masses 26 and generate viscosity in second fluid 18 as well as provide the diverting function. Thus, where bodies 20a are wedged in the tip of fracture 22, they will shear thin and optimize to the local fluid pressure conditions for limiting fracture growth and preferentially induce a new fracture off of fracture 22.

[00083] Conductivity limited “choke points” may also be reduced by the viscous material and proppant retained at restrictive flow locations in the complex fracture network during the treatment. The method thus provides greater versatility in treatment design, control and results than methods practiced previously.

[00084] FIG. 4 is a schematic illustration of possible choke points in a complex fracture network having a wellbore 30 from which extends a primary, propped fracture 32, and a plurality of more complex, unpropped fractures 34. The extent of SRV is illustrated. The value X_{pf} is the half-length of primary fracture 32, which is a bilength of the total fracture since a biwing (not shown) extends from wellbore 30 on the opposite side. The value d_f is the distance between unpropped fractures 34 and L_{sf} is the length of the secondary fractures extending from primary fracture 32. Potential conductivity choke points 36 are the locations in the fracture network having insufficient fracture conductivity. Such choke points restrict the rate of flow of hydrocarbons. The incidence and/or extent of conductivity choke points 36 may be reduced by viscous material 20 which may contain proppant and which are retained at such restrictive flow locations in the complex fracture network. The ability to pinpoint placement of proppant by selectively sized viscous material within the second fluid that become wedged at such locations will prevent or greatly reduce the lack of propped fracture conductivity at these locations.

[00085] Numerous advantages have been noted by use of the disclosed method to create a complex fracture network. Such advantages may be attributable to the fact that (i) the viscosity of the second fluid of the first stage is more adept than the conventional fluids such as slickwater and viscous crosslinked polymer systems for creating complex fracture networks; (ii) the second fluid containing the viscous material exhibits brine-like

viscosity from the surface to the fractures; (iii) the ability to target deeper and more narrower fracture regions before the viscous material interacts with the fracture walls; (iv) the promotion by the second fluid of increased hydraulic pressure during flow only within narrow width fractures; (v) the promotion by the second fluid of pressure-initiated fractures; vi) the ability of the second fluid with the defined viscous material to create deeper fluid diversion and fracture complexity; and (vi) the ability to target and engineer placement treatment additives deeper within the complex fractures.

[00086] Embodiments of the present disclosure thus offer advantages over the prior art and are well adapted to carry out one or more of the objects of this disclosure. However, the present disclosure does not require each of the components and acts described above and are in no way limited to the above-described embodiments or methods of operation. Any one or more of the above components, features and processes may be employed in any suitable configuration without inclusion of other such components, features and processes. Moreover, the present disclosure includes additional features, capabilities, functions, methods, uses and applications that have not been specifically addressed herein but are, or will become, apparent from the description herein, the appended drawings and claims.

[00087] The methods that may be described above or claimed herein and any other methods which may fall within the scope of the appended claims can be performed in any desired suitable order and are not necessarily limited to any sequence described herein or as may be listed in the appended claims. Further, the methods of the present disclosure do not necessarily require use of the particular embodiments shown and described herein, but are equally applicable with any other suitable structure, form and configuration of components.

[00088] While exemplary embodiments of the disclosure have been shown and described, many variations, modifications and/or changes of the system, apparatus and methods of the present disclosure, such as in the components, details of construction and operation, arrangement of parts and/or methods of use, are possible, contemplated by the patent applicant(s), within the scope of the appended claims, and may be made and used by one of ordinary skill in the art without departing from the spirit or teachings of the disclosure and scope of appended claims. Thus, all matter herein set forth or shown in

the accompanying drawings should be interpreted as illustrative, and the scope of the disclosure and the appended claims should not be limited to the embodiments described and shown herein.

CLAIMS

What is claimed is:

1. A method of fracturing a hydrocarbon-bearing subterranean formation penetrated by a wellbore which comprises, in a first stage:
 - (a) pumping a first fluid into the formation at a pressure sufficient to create or enlarge a primary fracture;
 - (b) pumping a second fluid into the formation, wherein the second fluid comprises the first fluid and a viscous material;
 - (c) creating or enlarging at least one secondary fracture having a directional orientation distinct from the directional orientation of the primary fracture by diverting the flow of the second fluid; and
 - (d) forming a complex fracture network by creating multiple fractures in the formation originating from the at least one secondary fracture.
2. The method of claim 1, wherein the viscous material is selected from the group consisting of viscoelastic surfactants, linear polymers, crosslinked polymers, surfactants, gelled hydrocarbons, and emulsion fluids and mixtures thereof.
3. The method of claim 2, wherein the viscous material is a gelled fluid of a viscoelastic surfactant, a linear polymer or a crosslinked polymer or a mixture thereof.
4. The method of claim 2, wherein the viscous material is selected from the group consisting of galactomannan gums, guar, derivatized guar, cellulose and cellulose derivatives, starch, starch derivatives, xanthan, derivatized xanthan and mixtures thereof.
5. The method of claim 2, wherein the viscous material is selected from the group consisting of crosslinked guar and crosslinked cellulosic derivatives and mixtures thereof.
6. The method of claim 1, wherein the viscous material is an emulsified fluid or a gelled oil.
7. The method of claim 1, wherein the first fluid or second fluid or both first fluid and second fluid further comprises a proppant.
8. The method of claim 7, wherein the proppant forms a partial monolayer within the created or enlarged fracture.

9. The method of claim 1, wherein the viscous material and the first fluid are present on the fly.

10. The method of claim 7, wherein during the first stage, at least one of the following factors varies:

- (a) the size of the proppant within the first fluid or second fluid;
- (b) the apparent specific gravity of the proppant within the first fluid and second fluid; or
- (c) the shape of the proppant within the first fluid and second fluid.

11. The method of claim 7, wherein the apparent specific gravity of the proppant in the first fluid and/or the second fluid is less than or equal to 2.0.

12. The method of claim 11, wherein the apparent specific gravity of the proppant in the first fluid and/or the second fluid is less than or equal to 1.2.

13. The method of claim 1, wherein the viscous material further comprises an internal additive selected from the group consisting of biocides, tracers, proppants, nanocoating agents, surfactants, scale inhibitors, asphaltene inhibitors, hydrogen sulfide scavengers, nanoparticles, polymer breakers, VES breakers, microemulsions, fines migration control additives, fracture imaging materials, piezoelectric particles, metal particles, metal complexes, metal salts, fines control agents, solid acids, solid high pH buffers, salts, chelants, oxidizers, plant and fish oils, mineral oils, shape memory polymers, fibers, glass spheres, encapsulations, and combinations thereof.

14. The method of claim 1, wherein the viscosity ratio, V_r , representing the viscosity of the viscous material at 0.01 sec^{-1} and 80° F to the viscosity of the first fluid at 0.01 sec^{-1} and 80° F is 100 or greater.

15. The method of claim 14, wherein the viscosity ratio, V_r , is 10,000 or greater.

16. The method of claim 15, wherein the viscosity ratio, V_r , is 100,000 or greater.

17. The method of claim 1, wherein the viscous material has an average particle size from about 500 nm to about 50 cm.

18. The method of claim 1, wherein the permeability of the hydrocarbon-bearing subterranean formation is less than or equal to 0.1 mD.

19. A method of fracturing a hydrocarbon-bearing subterranean formation penetrated by a wellbore which comprises, in a first stage:

(A) pumping a first fluid of low viscosity into the formation at a pressure sufficient to create or enlarge a primary fracture; and

(B) forming a complex fracture network comprising

(a) at least one secondary fracture having a directional orientation distinct from the directional orientation of the primary fracture; and

(b) a multiple of fractures originating from the at least one secondary fracture and having a directional orientation distinct from the directional orientation of the at least one secondary fracture

wherein the complex fracture network is formed by pumping a second fluid into the formation, wherein the second fluid comprises (i) the first fluid of low viscosity and (ii) a plurality of discrete bodies having a viscosity greater than the viscosity of the first fluid.

20. The method of claim 19, wherein the first fluid and the plurality of discrete bodies are present on the fly.

21. The method of claim 19, wherein the pumping of the first fluid and the second fluid reduces or minimizes conductivity-limited choke points within the complex fracture network.

22. A method of hydraulically fracturing a hydrocarbon-bearing subterranean formation penetrated by a wellbore which comprises, in a first stage:

(a) pumping a first fluid of low viscosity into the formation at a pressure sufficient to create or enlarge a primary fracture;

(b) pumping a second fluid into the formation, wherein the second fluid is prepared by adding to the first fluid a plurality of discrete bodies having a viscosity greater than the viscosity of the first fluid;

(a) creating or enlarging at least one secondary fracture having a directional orientation distinct from the directional orientation of the primary fracture by diverting the flow of the second fluid; and

(b) forming a complex fracture network through the addition of a diverting fluid into the formation and creating multiple fractures in the formation

originating from the at least one secondary fracture wherein the diverting fluid is prepared by adding to the first fluid a plurality of discrete bodies having a viscosity greater than the viscosity of the first fluid and wherein the multiple fractures are created by the action of the plurality of discrete bodies of viscous material in the diverting fluid.

23. The method of claim 22, wherein the second fluid and the diverting fluid are the same.

24. The method of claim 22, wherein the pumping of the first fluid, the second fluid and the diverting fluid reduces or minimizes conductivity-limited choke points within the complex fracture network.

25. The method of claim 22, wherein the permeability of the subterranean formation is less than or equal to 0.1mD.

26. A method of fracturing a hydrocarbon-bearing subterranean formation penetrated by a well to create a complex fracture network, the method comprising pumping into the formation, in a first stage a, first fluid and at least one second fluid, wherein the at least one second fluid is comprised of a viscous material and the first fluid, wherein:

(a) a primary fracture is created or enlarged by pumping into the formation the first fluid;

(b) at least one secondary fracture perpendicular and/or orthogonal to the primary fracture is created by diverting the flow of the at least one second fluid; and

(c) a complex fracture network comprising a series of fractures is created by continuously diverting the flow of the at least one second fluid through the formation and further wherein either:

(i) the surface area ratio (Sr), defined by S_{cf}/S_{pf} wherein S_{cf} is the surface area of the complex fracture network and S_{pf} is the surface area over the primary fracture, is greater when the first fluid and second fluid are pumped into the formation versus when only the first fluid is pumped into the formation; or

(ii) the conductivity ratio (Cr) defined by C_{cf}/C_{pf} , wherein C_{cf} is the conductivity of the complex fracture network and C_{pf} is the conductivity of the planar fracture divided by 1000 is greater when the first fluid and the at least one second fluid are pumped into the formation versus when only the first fluid is pumped into the formation.

27. The method of claim 25, wherein the first fluid is a brine.

28. The method of claim 25, wherein the first fluid contains a friction reducing agent.

29. The method of claim 25, wherein the conductivity within the complex fracture network ranges from nano-darcies at the tip of the fractures to milli-darcies to the primary fracture.

30. The method of claim 25, wherein the rate of pumping of the first fluid and/or the second fluid is varied during the fracturing.

31. The method of 25, wherein the subterranean formation is shale.

32. A method of generating diversion during the fracturing of a subterranean formation penetrated by a wellbore comprising:

(a) introducing into the wellbore, at a rate and pressure sufficient to fracture the subterranean formation, a brine fracturing fluid comprising:

(i) a lower viscosity fluid stream; and

(ii) a plurality of discrete bodies of a higher viscosity material;

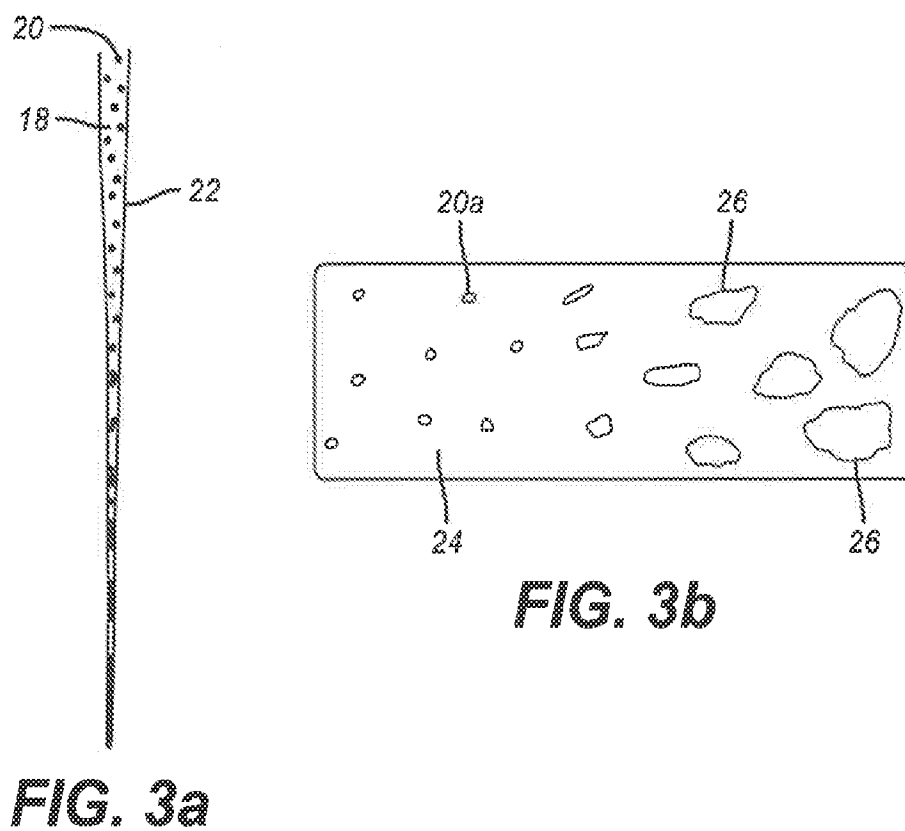
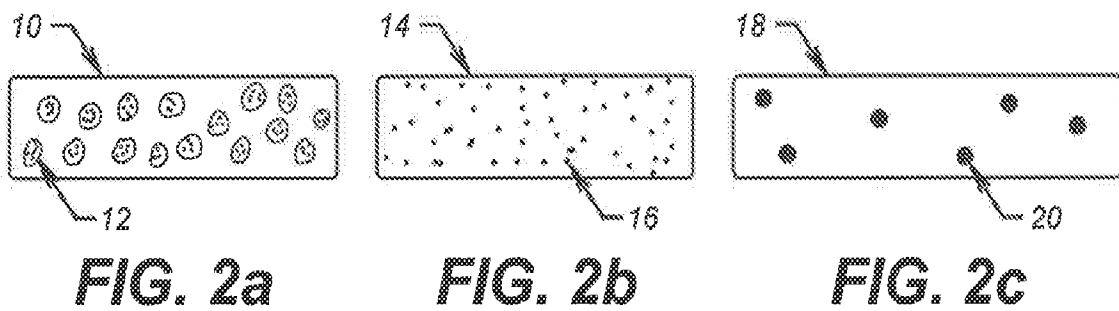
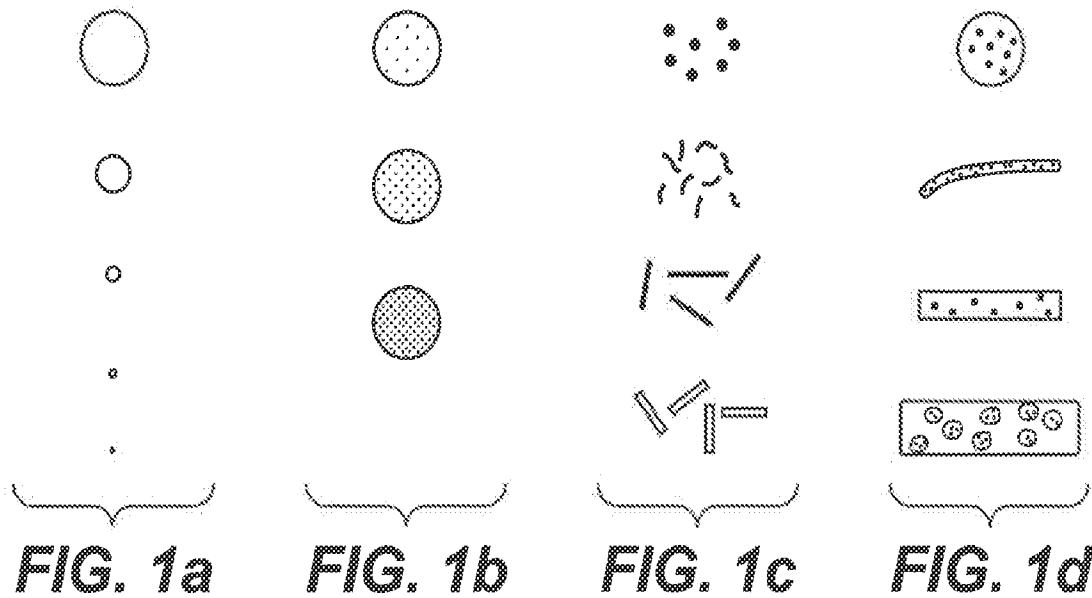
and

(b) diverting the lower viscosity fluid stream by action of the discrete bodies of the higher viscosity material.

33. The method of claim 30, wherein the discrete bodies generate viscosity in the lower viscosity fluid stream in narrow fractures and under high fracture wall shear.

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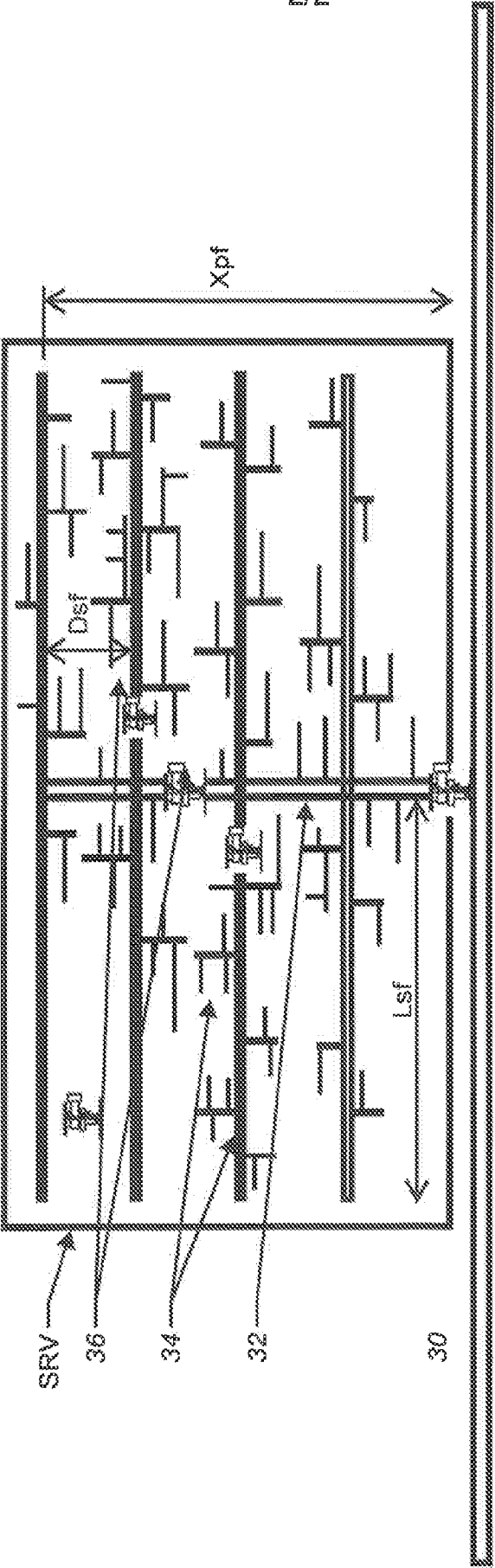


FIG. 4

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