Abstract: Improved methods for well stimulation and completion are provided. More particularly, the methods relate to stimulating and completing well bores while controlling formation sand migration and proppant flowback. One embodiment provides a method comprising: providing a subterranean formation penetrated by a well bore wherein the subterranean formation comprises at least one fracture; placing proppant coated with a tackifying agent into the far-well bore area of the fracture, wherein the far-well bore area of the fracture is an area within the fracture at least about 2 feet from the well bore in a direction substantially orthogonal to the well bore axis; and placing an agent capable of controlling particulate flowback into the well bore or near-well bore area of the fracture.
METHODS OF WELL STIMULATION AND COMPLETION

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application is a continuation-in-part application of commonly-owned U.S. Patent Application Serial Number 10/751,593, filed January 5, 2004, entitled "Methods of Well Stimulation and Completion," by Philip D. Nguyen, which is incorporated by reference herein for all purposes.

BACKGROUND OF THE INVENTION

[0002] The present invention relates to improved methods for well stimulation and completion. More particularly, the present invention relates to methods of stimulating and completing well bores while controlling formation sand migration and proppant flowback.

[0003] A subterranean formation may be treated to increase its permeability by hydraulically fracturing the formation to create or enhance one or more cracks or "fractures." The term "fracture" is defined herein to refer to any crack or open space that penetrates at least a portion of a subterranean formation, which may exist naturally, be created in the course of a subterranean treatment, or some combination thereof (e.g., a naturally-occurring fracture that is enlarged or enhanced in the course of a subterranean treatment). Such hydraulic fracturing is usually accomplished by injecting a viscous fracturing fluid into the subterranean formation at a rate and pressure sufficient to cause the formation to break down and produce one or more fractures or enhance one or more natural fractures. The fracture or fractures may be horizontal or vertical, with the latter usually predominating, and with the tendency toward vertical fractures increasing with the depth of the formation being fractured. The fracturing fluid is generally a highly viscous gel, emulsion, or foam that comprises a particulate material often referred to as proppant. In some fracturing operations, commonly known as "water fracturing" operations, the fracturing fluid viscosity is somewhat lowered and yet the proppant remains in suspension because the fracturing fluid is injected into the formation at a substantially higher velocity. Whether a highly viscous fluid is used or a less viscous fluid with a higher velocity, proppant is deposited in the fracture and functions, inter alia, to hold the fracture open while maintaining channels through which produced fluids can flow upon completion of the fracturing treatment.
To prevent the subsequent flowback of proppant and other unconsolidated particulates with the produced fluids, a portion of the proppant introduced into the fractures may be coated with a hardenable resin composition. When the fracturing fluid, which is the carrier fluid for the proppant, reverts to a thin fluid, the resin-coated proppant is deposited in the fracture, and the fracture closes on the proppant. Such partially closed fractures apply pressure on the resin-coated proppant particles, causing the particles to be forced into contact with each other while the resin composition hardens. The hardening of the resin composition under pressure brings about the consolidation of the resin-coated proppant particles into a substantially hard permeable mass having compressive and tensile strength that hopefully prevents unconsolidated proppant and formation sand from flowing out of the fractures with produced fluids.

Another method of preventing the flowback of proppant and other unconsolidated particulates involves the use of screen assemblies. Some of the early screen technology dictated that the screens had to be small enough to pass through the smallest diameter of the well bore on the way to its desired placement location where the diameter of the well bore may actually be larger. Developments in technology have lead to expandable screens such that a relatively small size or small diameter screen may be placed in a desired location along the well bore and then expanded to accommodate the actual size of the well bore at the point of placement. Flowback of the proppant or formation fines with formation fluids is undesirable as it may erode metal equipment, plug piping and vessels, and cause damage to valves, instruments, and other production equipment.

While the hydraulic fracturing techniques discussed above are commonly used on vertical well bores, they have not been widely used to stimulate horizontal well bores, particularly those penetrating hard rock formations such as sandstone, due, inter alia, to the fact that such formations usually require high fracturing pressures and result in complex and potentially unstable fracture geometries. The geometry of fractures caused by hydraulic pressure in horizontal well bores is primarily dependent on the formation in situ stresses. In situ stresses may be thought of as occurring in three orthogonal planes: vertical stress, maximum horizontal stress, and minimum horizontal stress. When subjected to hydraulic pressure, fractures, regardless of origin, attempt to propagate in planes orthogonal to the minimum horizontal stress. Thus, fracture configuration resulting from hydraulic pressure can depend on the orientation of the well bore with respect to the minimum
horizontal stress. Two such configurations have been the subject of interest in the art: longitudinal fractures that propagate in planes parallel to the well bore axis that are formed when a horizontal well bore is drilled parallel to the maximum horizontal stress (as depicted in Figure 1); and, transverse fractures that propagate in planes orthogonal to the well bore axis that are formed when a horizontal well bore is drilled perpendicular to the maximum horizontal stress (as depicted in Figure 2). In such formations, it is often necessary to puncture the formation to direct the fracture geometry.

[0007] The term "vertical well bore" as used herein refers to a well bore or portion of a well bore that is substantially vertical or deviated from vertical in an amount up to about 30°. The term "horizontal well bore" as used herein refers to a well bore or portion of a well bore that is substantially horizontal or at an angle from vertical in the range of from about 70° to about 90° or more. The term "highly deviated well bore" as used herein refers to a well bore or portion of a well bore that is angled from about 30° to about 70° from vertical.

SUMMARY OF THE INVENTION

[0008] The present invention relates to improved methods for well stimulation and completion. More particularly, the present invention relates to methods of stimulating and completing well bores while controlling formation sand migration and proppant flowback.

[0009] In one embodiment, the present invention provides a method comprising: providing a subterranean formation penetrated by a well bore wherein the subterranean formation comprises at least one fracture; placing proppant coated with a tackifying agent into an area of the fracture; placing an agent capable of controlling particulate flowback into the well bore or the near-well bore area of the fracture; and allowing the agent capable of controlling particulate flowback to displace at least a portion of the proppant coated with tackifying agent from one area of the fracture into the far-well bore area of the fracture.

[0010] In another embodiment, the present invention provides a method comprising: providing a subterranean formation penetrated by a well bore wherein the subterranean formation comprises at least one fracture; placing proppant coated with a tackifying agent into the far-well bore area of the fracture, wherein the far-well bore area of the fracture is an area within the fracture at least about 2 feet from the well bore in a direction substantially orthogonal to the well bore axis; and placing an agent capable of controlling particulate flowback into the well bore or near-well bore area of the fracture.
In another embodiment, the present invention provides a method of fracturing a formation surrounding a well bore comprising: hydraulically fracturing a formation to create or enhance at least one fracture; placing proppant coated with a tackifying agent into the far-well bore area of the fracture, wherein the far-well bore area of the fracture is an area within the fracture at least about 2 feet from the well bore in a direction substantially orthogonal to the well bore axis; and placing an agent capable of controlling particulate flowback into the well bore or near-well bore area of the fracture.

Other and further features and advantages of the present invention will be readily apparent to those skilled in the art upon a reading of the description of preferred embodiments which follows.

BRIEF DESCRIPTION OF THE DRAWINGS

Figure 1 illustrates an example of longitudinal fractures propagated in a plane substantially parallel to the well bore axis.

Figure 2 illustrates an example of transverse fractures propagated in a plane substantially orthogonal to the well bore axis.

Figure 3 illustrates an example of puncture orientations that may be used in the methods of the present invention.

DESCRIPTION OF PREFERRED EMBODIMENTS

The present invention relates to improved methods for well stimulation and completion. More particularly, the present invention relates to methods of stimulating and completing well bores while controlling formation sand migration and proppant flowback.

The present invention provides methods that may be used, among other purposes, to stimulate production of hydrocarbons from a subterranean formation and/or controlling particulate migration into well bores penetrating subterranean formations. Certain embodiments of the present invention provide methods that comprise the steps of providing a subterranean formation penetrated by a well bore wherein the subterranean formation comprises at least one fracture, placing proppant coated with a tackifying agent into the far-well bore area of the fracture, and placing an agent capable of controlling particulate flowback into the near-well bore area. The term "agent capable of controlling particulate flowback" is defined herein to include materials and/or devices that, when placed in a subterranean formation or well bore, can hinder or prevent loose particulates in the
subterranean formation (e.g., proppant particulates, formation sands, etc.) from migrating into the well bore penetrating that formation. In certain embodiments, the far-well bore area of the fracture is an area within the fracture at least about 2 feet from the well bore in a direction substantially orthogonal to the well bore axis. In certain embodiments, the far-well bore area of the fracture is an area within the fracture at least about 3 feet from the well bore in a direction substantially orthogonal to the well bore axis. Placing proppant coated with tackifying agent into the far-well bore area acts, \textit{inter alia}, to help control the migration of formation sands. Placing an agent capable of controlling particulate flowback in the fracture near the well bore and/or in the well bore acts, \textit{inter alia}, to keep the proppant in place instead of producing it along with the produced fluids.

[0018] In the methods of the present invention, at least one fracture in the subterranean formation may be provided, created, and/or enhanced. The term "fracture" is defined herein to refer to any crack or open space that penetrates at least a portion of a subterranean formation, which may exist naturally, be created in the course of a subterranean treatment, or some combination thereof (e.g., a naturally-occurring fracture that is enlarged or enhanced in the course of a subterranean treatment). Examples of subterranean treatments that may be used to create and/or enhance such fractures include, but are not limited to, hydraulic fracturing treatments, frac-packing treatments, hydrajetting treatments, and the like. In certain embodiments, the fracture may have been created and/or enhanced prior to the commencement of a method of the present invention. In certain embodiments, the fracture may be created and/or enhanced in the course of a method of the present invention.

[0019] Proppant particles used in accordance with the present invention are generally of a size such that formation particulates that may migrate with produced fluids are prevented from being produced from the subterranean zone. Any suitable proppant may be used, including graded sand, bauxite, ceramic materials, glass materials, walnut hulls, polymer beads and the like. Generally, the proppant particles have a size in the range of from about 4 to about 100 mesh, U.S. sieve series. The proppant coated with tackifying agent and placed in the far-well bore area may be the same as or different than a proppant coated with resin that may be placed in the near-well bore area.

[0020] A tackifying agent is a substance that remains sticky rather than curing over time. Placing proppant coated with a tackifying agent into the far-well bore area of the fracture will help prevent formation sand from invading the near-well bore area of the
fracture as the sands become trapped by the sticky character of the tackifying agent. Compounds suitable for use as a tackifying compound in the present invention comprise substantially any compound that, when in liquid form or in a solvent solution, will form a sticky, non-hardening coating upon a particulate. A particularly preferred group of tackifying compounds comprise polyamides that are liquids or in solution at the temperature of the subterranean formation such that the polyamides are, by themselves, non-hardening when present on the particulates introduced into the subterranean formation. A particularly preferred product is a condensation reaction product comprised of commercially available polyacids and a polyamine. Such commercial products include compounds such as mixtures of $C_{36}$ dibasic acids containing some trimer and/or higher oligomers and also small amounts of monomer acids that are reacted with polyamines. Other polyacids include trimer acids, synthetic acids produced from fatty acids, maleic anhydride and acrylic acid and the like. Such acid compounds are commercially available from companies such as Witco Corporation, Union Camp, Chemtall, and Emery Industries. The reaction products are available from, for example, Champion Technologies, Inc. and Witco Corporation. Additional compounds which may be used as tackifying compounds include liquids and solutions of, for example, polyesters, polycarbonates and polycarbonates, natural resins such as shellac and the like. Suitable tackifying compounds are described in U.S. Patent Number 5,853,048 issued to Weaver, et al. and U.S. Patent Number 5,833,000 issued to Weaver, et al., the disclosures of which are herein incorporated by reference.

[0021] The agent capable of controlling particulate flowback may comprise any material and/or device that, when placed in a subterranean formation or well bore, can hinder or prevent loose particulates in the subterranean formation (e.g., proppant particulates, formation sands, etc.) from migrating into the well bore penetrating that formation. The agent capable of controlling particulate flowback may comprise proppant particulates, proppant particulates coated with resin (e.g., a curable resin), fibrous materials, deformable particulates, a screen (e.g., sized to control the flowback of the proppant that has been placed in a subterranean formation), or a mixture or combination thereof. In certain embodiments, the agent capable of controlling particulate flowback may comprise a mixture of fibrous materials and proppant particulates. The fibrous materials may comprise multiple fibers with segment lengths of about less than about 0.5 inches and diameters of about 10 to about 50 microns. Among other purposes, the fibers may form a network that provides resistance to
movement of particulates. Examples of fibrous materials that may be suitable for use in the present invention are described in U.S. Patent Nos. 6,172,011, 5,501,275, 5,439,055, and 5,330,005, the relevant disclosures of which are herein incorporated by reference. In certain embodiments, the agent capable of controlling particulate flowback may comprise deformable particulates. Deformable particulates may, inter alia, allow surrounding proppant particulates to become embedded onto their bodies as stress closure is applied, which may allow the proppant pack to stabilize and minimizing the movement of proppant. Examples of deformable particulates that may be suitable for use in the present invention are described in U.S. Patent Nos. 6,330,916 and 6,059,034, the relevant disclosures of which are herein incorporated by reference.

[0022] In certain embodiments, the agent capable of controlling particulate flowback may be placed in the near-well bore area of the fracture after the proppant coated with tackifying agent is placed in the far-well bore area of the fracture. For example, where the agent capable of controlling particulate flowback comprises a resin-coated proppant, the resin may cure and harden into a consolidated mass that is capable of allowing fluid production and yet will provide a barrier to flowback of the tackified proppant, the resin-coated proppant, and the formation sands.

[0023] In certain embodiments, the agent capable of controlling particulate flowback may be used to displace a portion of the proppant coated with tackifying agent from one area of the fracture into the far-well bore area of the fracture. For example, a slurry that comprises the agent capable of controlling particulate flowback (e.g., a proppant coated with a curable resin) may be pumped into the well bore at or above a pressure sufficient to displace the proppant coated with tackifying agent into the far-well bore area of the fracture. In some instances, the agent capable of controlling particulate flowback may comprise a screen that, when placed in the well bore or near-well bore area of the fracture, displaces at least a portion of the proppant coated with tackifying agent into the far-well bore area of the fracture.

[0024] Resins suitable for use in the resin slurries in the present invention include, but are not limited to, two-component epoxy-based resins, furan-based resins, phenolic-based resins, high-temperature (HT) epoxy-based resins, and phenol/phenol formaldehyde/furfuryl alcohol resins.
Selection of a suitable resin-type coating material may be affected by the temperature of the subterranean formation to which the fluid will be introduced. By way of example, for subterranean formations having a bottom hole static temperature ("BHST") ranging from about 60°F to about 250°F, two-component epoxy-based resins comprising a hardenable resin component and a hardening agent component containing specific hardening agents may be preferred. For subterranean formations having a BHST ranging from about 300°F to about 600°F, a furan-based resin may be preferred. For subterranean formations having a BHST ranging from about 200°F to about 400°F, either a phenolic-based resin or a one-component HT epoxy-based resin may be suitable. For subterranean formations having a BHST of at least about 175°F, a phenol/phenol formaldehyde/furfuryl alcohol resin also may be suitable.

One resin suitable for use in the methods of certain embodiments of the present invention is a two-component epoxy based resin comprising a hardenable resin component and a hardening agent component. The hardenable resin component is comprised of a hardenable resin and an optional solvent. The solvent may be added to the resin to reduce its viscosity for ease of handling, mixing and transferring. It is within the ability of one skilled in the art, with the benefit of this disclosure, to determine whether and how much solvent may be needed to achieve a viscosity suitable to the subterranean conditions. Factors that may affect this decision include geographic location of the well and the surrounding environmental conditions. An alternate way to reduce the viscosity of the liquid hardenable resin is to heat it. This method avoids the use of a solvent altogether, which may be desirable in some circumstances. The second component of the two-component epoxy based resin is the liquid hardening agent component, and it is comprised of a hardening agent, a silane coupling agent, a surfactant, an optional hydrolyzable ester for, inter alia, breaking gelled fracturing fluid films on the proppant particles, and an optional liquid carrier fluid for, inter alia, reducing the viscosity of the liquid hardening agent component. It is within the ability of one skilled in the art, with the benefit of this disclosure, to determine whether and how much liquid carrier fluid is needed to achieve a viscosity suitable to the subterranean conditions.

Examples of hardenable resins that can be used in the liquid hardenable resin component include, but are not limited to, organic resins such as bisphenol A-epichlorohydrin resin, polyepoxide resin, novolak resin, polyester resin, phenol-aldehyde
resin, urea-aldehyde resin, fiiran resin, urethane resin, glycidyl ethers, and mixtures thereof. Of these, bisphenol A-epichlorohydrin resin is preferred. The resin used is included in the liquid hardenable resin component in an amount sufficient to consolidate the coated particulates. In some embodiments of the present invention, the resin used is included in the liquid hardenable resin component in the range of from about 70% to about 100% by weight of the liquid hardenable resin component.

[0028] Any solvent that is compatible with the hardenable resin and achieves the desired viscosity effect is suitable for use in the present invention. Preferred solvents are those having high flash points (most preferably about 125°F) due to in part to safety concerns. As described above, use of a solvent in the hardenable resin composition is optional but may be desirable to reduce the viscosity of the hardenable resin component for a variety of reasons including ease of handling, mixing, and transferring. It is within the ability of one skilled in the art, with the benefit of this disclosure, to determine whether and how much solvent is needed to achieve a suitable viscosity. Solvents suitable for use in the present invention include, but are not limited to, butylglycidyl ether, dipropylene glycol methyl ether, dipropylene glycol dimethyl ether, dimethyl formamide, diethylene glycol methyl ether, ethylene glycol butyl ether, diethylene glycol butyl ether, propylene carbonate, methanol, butyl alcohol, d-limonene, and fatty acid methyl esters.

[0029] Examples of the hardening agents that can be used in the liquid hardening agent component of the two-component epoxy based resin of the present invention include, but are not limited to, amines, aromatic amines, polyamines, aliphatic amines, cyclo-aliphatic amines, amides, polyamides, 2-ethyl-4-methyl imidazole, and 1,1,3-trichlorotrifluoroacetone. Selection of a preferred hardening agent depends, in part, on the temperature of the formation in which the hardening agent will be used. By way of example and not of limitation, in subterranean formations having a temperature from about 60°F to about 250°F, amines and cyclo-aliphatic amines such as piperidine, triethylamine, N,N-dimethylaminopyridine, benzylidimethylamine, tris(dimethylaminomethyl) phenol, and 2-(N2N-dimethylaminomethyl)phenol are preferred with N,N-dimethylaminopyridine most preferred. In subterranean formations having higher temperatures, 4,4’-diaminodiphenyl sulfone may be a suitable hardening agent. The hardening agent used is included in the liquid hardening agent component in an amount sufficient to consolidate the coated particulates. In some embodiments of the present invention, the hardening agent used is included in the liquid...
hardenable resin component in the range of from about 40% to about 60% by weight of the liquid hardening agent component.

[0030] The silane coupling agent may be used, inter alia, to act as a mediator to help bond the resin to the sand surface. Examples of silane coupling agents that can be used in the liquid hardening agent component of the two-component consolidation fluids of the present invention include, but are not limited to, n-2-(aminoethyl)-3-aminopropyltrimethoxysilane, 3-glycidoxypropyltrimethoxysilane, and n-beta-(aminoethyl)-gamma-aminopropyl trimethoxysilane. The silane coupling agent used is included in the liquid hardening agent component in an amount capable of sufficiently bonding the resin to the particulate. In some embodiments of the present invention, the silane coupling agent used is included in the liquid hardenable resin component in the range of from about 0.1% to about 3% by weight of the liquid hardening agent component.

[0031] Any surfactant compatible with the liquid hardening agent may be used in the present invention. Such surfactants include, but are not limited to, an ethoxylated nonyl phenol phosphate ester, mixtures of one or more cationic surfactants and one or more nonionic surfactants, and an alkyl phosphonate surfactant. The mixtures of one or more cationic and nonionic surfactants are described in U.S. Patent No. 6,311,733, the relevant disclosure of which is incorporated herein by reference. A C12 - C22 alkyl phosphonate surfactant is preferred. The surfactant or surfactants used are included in the liquid hardening agent component in an amount in the range of from about 2% to about 15% by weight of the liquid hardening agent component.

[0032] Use of a diluent or liquid carrier fluid in the hardenable resin composition is optional and may be used to reduce the viscosity of the hardenable resin component for ease of handling, mixing and transferring. It is within the ability of one skilled in the art, with the benefit of this disclosure, to determine whether and how much liquid carrier fluid is needed to achieve a viscosity suitable to the subterranean conditions. Any suitable carrier fluid that is compatible with the hardenable resin and achieves the desired viscosity effects is suitable for use in the present invention. The liquid carrier fluids that can be used in the liquid hardening agent component of the two-component epoxy based coating material of the present invention preferably include those having high flash points (most preferably above about 125°F). Examples of liquid carrier fluids suitable for use in the present invention include, but are not limited to, dipropylene glycol methyl ether, dipropylene glycol dimethyl
ether, dimethyl formamide, diethylene glycol methyl ether, ethylene glycol butyl ether, diethylene glycol butyl ether, propylene carbonate, d-limonene, and fatty acid methyl esters.

[0033] Another resin suitable for use in the methods of the present invention is a furan-based resin. Suitable furan-based resins include, but are not limited to, furfuryl alcohol, a mixture furfuryl alcohol with an aldehyde, and a mixture of furan resin and phenolic resin. The furan-based resin may be combined with a solvent to control viscosity if desired. Suitable solvents for use in the furan-based consolidation fluids of the present invention include, but are not limited to 2-butoxy ethanol, butyl acetate, and furfuryl acetate.

[0034] Still another resin suitable for use in the methods of the present invention is a phenolic-based resin. Suitable phenolic-based resins include, but are not limited to, terpolymers of phenol, phenolic formaldehyde resins, and a mixture of phenolic and furan resins. The phenolic-based resin may be combined with a solvent to control viscosity if desired. Suitable solvents for use in the phenolic-based consolidation fluids of the present invention include, but are not limited to butyl acetate, butyl lactate, furfuryl acetate, and 2-butoxy ethanol.

[0035] Another resin suitable for use in the methods of the present invention is a HT epoxy-based resin. Suitable HT epoxy-based components included, but are not limited to, bisphenol A-epichlorohydrin resin, polyeoxide resin, novolac resin, polyester resin, glycidyl ethers, and mixtures thereof. The HT epoxy-based resin may be combined with a solvent to control viscosity if desired. Suitable solvents for use with the HT epoxy-based resins of the present invention are those solvents capable of substantially dissolving the HT epoxy-resin chosen for use in the consolidation fluid. Such solvents include, but are not limited to, dimethyl sulfoxide and dimethyl formamide. A co-solvent such as dipropylene glycol methyl ether, dipropylene glycol dimethyl ether, dimethyl formamide, diethylene glycol methyl ether, ethylene glycol butyl ether, diethylene glycol butyl ether, propylene carbonate, d-limonene, and fatty acid methyl esters, also may be used in combination with the solvent.

[0036] Yet another resin suitable for use in the methods of the present invention is a phenol/phenol formaldehyde/furfuryl alcohol resin comprising from about 5% to about 30% phenol, from about 40% to about 70% phenol formaldehyde, from about 10 to about 40% furfuryl alcohol, from about 0.1% to about 3% of a silane coupling agent, and from about 1% to about 15% of a surfactant. In the phenol/phenol formaldehyde/furfuryl alcohol resins
suitable for use in the methods of the present invention, suitable silane coupling agents include, but are not limited to, n-2-(aminoethyl)-3-aminopropyltrimethoxysilane, 3-glycidoxypropyltrimethoxysilane, and n-beta-(aminoethyl)-gamma-aminopropyl trimethoxysilane. Suitable surfactants include, but are not limited to, an ethoxylated nonyl phenol phosphate ester, mixtures of one or more cationic surfactants and one or more non-ionic surfactants, and an alkyl phosphonate surfactant.

[0037] Some embodiments of the methods of the present invention further comprise the step of puncturing the subterranean formation surrounding a horizontal well bore located in a substantially consolidated subterranean formation before the step of hydraulically fracturing the formation. The stimulation and completion methods of the present invention comprising the step of puncturing the formation are particularly well suited for use in highly deviated and horizontal well bores that penetrate substantially consolidated formations. Substantially consolidated formations help in maintaining the integrity of the well bore, and thus helping to prevent well bore collapse and excessive formation sand migration into the well bore. In puncturing the formation, unconsolidated or weakly consolidated regions located above or below the substantially consolidated well bore region may be put into fluid communication with the well bore, thus enhancing production without destabilizing the well bore. The methods of the present invention are useful in open hole well bores, well bores having a non-cemented liner, and cased and cemented well bores.

[0038] In most subterranean formation structures, consolidated and unconsolidated strata form on top of one another. Thus, the punctures are preferably performed at either the top side of the horizontal well bore (i.e., 12-o’clock or 0°), the bottom side of the horizontal well bore (i.e., 6-o’clock or 180°), or both (substantially 180° phasing). Figure 3 illustrates these three orientations of punctures in a horizontal well bore. By way of example, where the substantially consolidated portion of the formation containing the well bore is bordered on the top by an unconsolidated region, at least the top of the horizontal well bore is preferably punctured.

[0039] Any known puncturing technique may be used in the methods of the present invention, including but not limited to, perforating and hydrajetting. Hydrajetting generally involves the use of a hydrajetting tool such as those described in U.S. Patent Nos. 5,765,642, 5,494,103, and 5,361,856, the relevant portions of which are herein incorporated by reference. In a common hydrajetting operation, a hydrajetting tool having at least one
fluid jet forming nozzle is positioned adjacent to a formation to be fractured, and fluid is then jetted through the nozzle against the formation at a pressure sufficient to form a cavity, or slot therein to fracture the formation by stagnation pressure in the cavity. Because the jetted fluids would have to flow out of the slot in a direction generally opposite to the direction of the incoming jetted fluid, they are trapped in the slot and create a relatively high stagnation pressure at the tip of a cavity. This high stagnation pressure may cause a micro-fracture to be formed that extends a short distance into the formation. That micro-fracture may be further extended by pumping a fluid into the well bore to raise the ambient fluid pressure exerted on the formation while the formation is being hydrajetted. Such a fluid in the well bore will flow into the slot and fracture produced by the fluid jet and, if introduced into the well bore at a sufficient rate and pressure, may be used to extend the fracture an additional distance from the well bore into the formation.

[0040] Therefore, the present invention is well adapted to attain the ends and advantages mentioned as well as those that are inherent therein. The particular embodiments disclosed above are illustrative only, as the present invention may be modified and practiced in different but equivalent manners apparent to those skilled in the art having the benefit of the teachings herein. While numerous changes may be made by those skilled in the art, such changes are encompassed within the spirit of this invention as defined by the appended claims. Furthermore, no limitations are intended to the details of construction or design herein shown, other than as described in the claims below. It is therefore evident that the particular illustrative embodiments disclosed above may be altered or modified and all such variations are considered within the scope and spirit of the present invention. In particular, every range of values (e.g., "from about a to about b," or, equivalently, "from approximately a to b," or, equivalently, "from approximately a-b") disclosed herein is to be understood as referring to the power set (the set of all subsets) of the respective range of values. The terms in the claims have their plain, ordinary meaning unless otherwise explicitly and clearly defined by the patentee.
What is claimed is:

1. A method comprising:
   providing a subterranean formation penetrated by a well bore wherein the subterranean formation comprises at least one fracture;
   placing proppant coated with a tackifying agent into an area of the fracture;
   placing an agent capable of controlling particulate flowback into the well bore or the near-well bore area of the fracture; and
   allowing the agent capable of controlling particulate flowback to displace at least a portion of the proppant coated with tackifying agent from one area of the fracture into the far-well bore area of the fracture.

2. The method of claim 1 wherein the tackifying agent is selected from the group consisting of polyamides, polyesters, polycarbonates, polycarbamates, natural resins, and combinations thereof.

3. The method of claim 1 wherein the agent capable of controlling particulate flowback comprises a screen.

4. The method of claim 3 wherein the screen is sized to control the flowback of the proppant coated with a tackifying agent.

5. The method of claim 1 wherein the agent capable of controlling particulate flowback comprises proppant coated with curable resin.

6. The method of claim 5 wherein the curable resin comprises a hardenable resin component comprising a hardenable resin and a hardening agent component comprising a liquid hardening agent, a silane coupling agent, and a surfactant.

7. The method of claim 5 wherein the resin composition comprises a furan-based resin selected from the group consisting of furfuryl alcohol, mixtures of furfuryl alcohol with an aldehyde, mixtures of furan resin and phenolic resin, and mixtures thereof.

8. The method of claim 7 further comprising a solvent selected from the group consisting of 2-butoxy ethanol, butyl acetate, furfuryl acetate, and mixtures thereof.

9. The method of claim 5 wherein the resin composition comprises a phenolic-based resin selected from the group consisting of terpolymers of phenol, phenolic formaldehyde resins, mixtures of phenolic and furan resin, and mixtures thereof.
10. The method of claim 9 wherein the resin composition further comprises a solvent selected from the group consisting of butyl acetate, butyl lactate, furfuryl acetate, 2-butoxy ethanol, and mixtures thereof.

11. The method of claim 5 wherein the resin composition comprises a HT epoxy-based resin selected from the group consisting of bisphenol A-epichlorohydrin resins, polyepoxide resins, novolac resins, polyester resins, glycidyl ethers, and mixtures thereof.

12. The method of claim 11 wherein the resin composition further comprises a solvent selected from the group consisting of dimethyl sulfoxide, dimethyl formamide, dipropylene glycol methyl ether, dipropylene glycol dimethyl ether, dimethyl formamide, diethylene glycol methyl ether, ethylene glycol butyl ether, diethylene glycol butyl ether, propylene carbonate, d-limonene, fatty acid methyl esters, and mixtures thereof.

13. The method of claim 5 wherein the resin composition comprises a phenol/phenol formaldehyde/furfuryl alcohol resin comprising from about 5% to about 30% phenol, from about 40% to about 70% phenol formaldehyde, from about 10 to about 40% furfuryl alcohol, from about 0.1% to about 3% of a silane coupling agent, and from about 1% to about 15% of a surfactant.

14. The method of claim 1 wherein providing a subterranean formation that comprises a fracture comprises hydraulically fracturing the subterranean formation surrounding the well bore to create or enhance the fracture.

15. The method of claim 1 wherein the far-well bore area of the fracture is an area within the fracture at least about 2 feet from the well bore in a direction substantially orthogonal to the well bore axis.

16. A method comprising:

providing a subterranean formation penetrated by a well bore wherein the subterranean formation comprises at least one fracture;

placing proppant coated with a tackifying agent into the far-well bore area of the fracture, wherein the far-well bore area of the fracture is an area within the fracture at least about 2 feet from the well bore in a direction substantially orthogonal to the well bore axis; and

placing an agent capable of controlling particulate flowback into the well bore or near-well bore area of the fracture.
17. The method of claim 16 wherein the agent capable of controlling particulate flowback comprises proppant coated with curable resin.

18. A method of fracturing a formation surrounding a well bore comprising:
   hydraulically fracturing a formation to create or enhance at least one fracture;
   placing proppant coated with a tackifying agent into the far-well bore area of the fracture, wherein the far-well bore area of the fracture is an area within the fracture at least about 2 feet from the well bore in a direction substantially orthogonal to the well bore axis; and
   placing an agent capable of controlling particulate flowback into the well bore or near-well bore area of the fracture.

19. The method of claim 18 wherein the agent capable of controlling particulate flowback comprises proppant coated with curable resin.

20. The method of claim 18 wherein the curable resin comprises a hardenable resin component comprising a hardenable resin and a hardening agent component comprising a liquid hardening agent, a silane coupling agent, and a surfactant.
## INTERNATIONAL SEARCH REPORT

### A. CLASSIFICATION OF SUBJECT MATTER

| INV. | C09K8/56 | C09K8/62 | C09K8/80 |

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

### B. FIELDS SEARCHED

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

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

**EPO-Internal**

### C. DOCUMENTS CONSIDERED TO BE RELEVANT

<table>
<thead>
<tr>
<th>Category</th>
<th>Citation of document, with indication, where appropriate, of the relevant passages</th>
<th>Relevant to claim</th>
</tr>
</thead>
</table>

- Special categories of cited documents
  - 'A' document defining the general state of the art which is not considered to be of particular relevance
  - 'E' earlier document but published on or after the international filing date
  - 'L' document of particular relevance, the claimed invention cannot be considered to involve an inventive step when the cited document is taken alone
  - 'O' document referring to an oral disclosure, use exhibitions or other means
  - 'P' document published prior to the international filing date but later than the priority date claimed
  - 'T' later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention
  - 'X' later document published after the international filing date or priority date and not in conflict with the application but cited to establish the publication date of another invention or other special reason (as specified)
  - 'Y1' document of particular relevance, the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art
  - 'Z' document member of the same patent family

- Date of the actual completion of the international search: 24 August 2007
- Date of mailing of the international search report: 03/09/2007
- Name and mailing address of the ISA/ European Patent Office, P B 5818 Patentlaan 2 NL - 2280 HV Rijswijk Tel (+31-70) 340-2040, Tx 31651 epo.nl Fax (+31-70) 340-3016
- Authorized officer: Zimpfer , Emmanuel
<table>
<thead>
<tr>
<th>Patent document cited in search report</th>
<th>Publication date</th>
<th>Patent family member(s)</th>
<th>Publication date</th>
</tr>
</thead>
<tbody>
<tr>
<td>US 2005145385 A1</td>
<td>07-07-2005</td>
<td>AR 047632 A1</td>
<td>01-02-2006</td>
</tr>
<tr>
<td></td>
<td></td>
<td>BR P10418321 A</td>
<td>02-05-2007</td>
</tr>
<tr>
<td></td>
<td></td>
<td>WO 200506457 A1</td>
<td>21-07-2005</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CA 2337122 A1</td>
<td>06-09-2001</td>
</tr>
<tr>
<td></td>
<td></td>
<td>NO 20011115 A</td>
<td>07-09-2001</td>
</tr>
<tr>
<td>US 2005274517 A1</td>
<td>15-12-2005</td>
<td>AU 2005252419 A1</td>
<td>22-12-2005</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CA 2565174 A1</td>
<td>22-12-2005</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CN 1965146 A</td>
<td>16-05-2007</td>
</tr>
<tr>
<td></td>
<td></td>
<td>DE 112005001353 T5</td>
<td>03-05-2007</td>
</tr>
<tr>
<td></td>
<td></td>
<td>WO 2005121505 A2</td>
<td>22-12-2005</td>
</tr>
</tbody>
</table>