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Methods for remediating a subterranean environment. Methods comprising introducing a cleanup fluid through a well bore and into a portion of a subterranean formation penetrated by the well bore, applying a pressure pulse to the cleanup fluid, and introducing a

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consolidating agent through the well bore and into the portion of the subterranean formation. Methods of cleaning a sand control screen comprises introducing a cleanup fluid through a sand control screen and into a portion of a subterranean formation, the sand control screen located in a well bore that penetrates the subterranean formation; applying a pressure pulse to the cleanup fluid; and introducing a consolidating agent through the sand control screen and into the portion of the subterranean formation.

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(54) Title: METHODS OF CLEANING SAND CONTROL SCREENS AND GRAVEL PACKS

(57) Abstract: Methods for remediating a subterranean environment. Methods comprising introducing a cleanup fluid through a well bore and into a portion of a subterranean formation penetrated by the well bore, applying a pressure pulse to the cleanup fluid, and introducing a consolidating agent through the well bore and into the portion of the subterranean formation. Methods of cleaning a sand control screen comprises introducing a cleanup fluid through a sand control screen and into a portion of a subterranean formation, the sand control screen located in a well bore that penetrates the subterranean formation; applying a pressure pulse to the cleanup fluid; and introducing a consolidating agent through the sand control screen and into the portion of the subterranean formation.

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METHODS OF CLEANING SAND CONTROL SCREENS AND GRAVEL PACKS

BACKGROUND

The present invention relates to methods for treating a subterranean environment. More particularly, the present invention relates to the remedial treatment of a subterranean environment with pressure pulsing and consolidating agents.

Gravel packing operations are commonly performed in subterranean formations to control unconsolidated particulates. A typical gravel packing operation involves placing a filtration bed containing gravel particulates near the well bore that neighbors the zone of interest. The filtration bed acts as a sort of physical barrier to the transport of unconsolidated particulates to the well bore that could be produced with the produced fluids. One common type of gravel packing operation involves placing a sand control screen in the well bore and packing the annulus between the screen and the well bore with gravel particulates of a specific size designed to prevent the passage of formation sand. The sand control screen is generally a filter assembly used to retain the gravel placed during the gravel pack operation. In addition to the use of sand control screens, gravel packing operations may involve the use of a wide variety of sand control equipment, including liners (*e.g.*, slotted liners, perforated liners, etc.), combinations of liners and screens, and other suitable apparatus. A wide range of sizes and screen configurations are available to suit the characteristics of the gravel particulates used. Similarly, a wide range of sizes of gravel particulates are available to suit the characteristics of the unconsolidated particulates. The resulting structure presents a barrier to migrating sand from the formation while still permitting fluid flow.

One problem encountered after a gravel packing operation is migrating fines that plug the gravel pack and sand control screen, impeding fluid flow and causing production levels to drop. As used in this disclosure, the term "fines" refers to loose particles, such as formation fines, formation sand, clay particulates, coal fines, resin particulates, crushed proppant or gravel particulates, and the like. These migrating fines can also obstruct fluid pathways in the gravel pack lining the well. In particular, *in situ* fines mobilized during production, or injection, can lodge themselves in sand control screens and gravel packs, preventing or reducing fluid flow there through. Similar problems are also encountered due to scale buildup on sand control screens and gravel packs, as well as precipitates (*e.g.*, solid salts

(*e.g.*, inorganic salts such as calcium or barium sulfates, calcium carbonate, calcium/barium scales)) on the sand control screen and the gravel pack.

Well-stimulation techniques, such as matrix acidizing, have been developed to remediate wells affected by these problems. In matrix acidizing, thousands of gallons of acid are injected into the well to dissolve away precipitates, fines, or scale on the inside of tubulars, trapped in the openings of the screen, in the pore spaces of gravel pack or matrix formation. A corrosion inhibitor generally is used to prevent tubulars from corrosion. Also, the acid must be removed from the well. Often, the well must also be flushed with pre- and post-acid solutions. Aside from the difficulties of determining the proper chemical composition for these fluids and pumping them down the well, the environmental costs of matrix acidizing can render the process undesirable. Additionally, matrix acidizing treatments generally only provide a temporary solution to these problems. Screens, preslotted liners, and gravel packs may also be flushed with a brine solution to remove solid particles. While this brine treatment is cheap and relatively easy to complete, it offers only a temporary and localized respite from the plugging fines. Moreover, frequent flushing can damage the formation and further decrease production.

Pressure pulsing is another technique that has been used to address these problems. "Pressure pulsing," as used in this disclosure, refers to the application of period increases, or "pulses," in the pressure of fluid introduced into the formation so as to deliberately vary fluid pressure applied to the formation. Pressure pulsing has been found to be effective at cleaning fluid flow lines and well bores. The step of applying the pressure pulse to the fluid may be performed at the surface or in the well bore. Pulsing may occur using any suitable methodology, including raising and lowering a string of tubing located within the well bore, or by employing devices, such as a fluidic oscillators, that rely on fluid oscillation effects to create pressure pulsing. In some embodiments, the pressure pulse may be generated by flowing the fluid through a pulsonic device, such as a fluidic oscillator. For instance, the fluid may be flowed through a suitable pulsonic device that is attached at the end of coiled tubing so as to generate the desired pressure pulsing in the fluid. Generally, the fluid may be flowed into the pulsonic device at a constant rate and pressure such that a pressure pulse is applied to the fluid as it passes through the pulsonic device.

SUMMARY

The present invention relates to methods for treating a subterranean environment. More particularly, the present invention relates to the remedial treatment of a subterranean environment with pressure pulsing and consolidating agents.

In one embodiment, the present invention provides a method of remediating a subterranean environment comprising: introducing a cleanup fluid through a well bore and into a portion of a subterranean formation penetrated by the well bore; applying a pressure pulse to the cleanup fluid; and introducing a consolidating agent through the well bore and into the portion of the subterranean formation.

In another embodiment, the present invention provides a method of cleaning a sand control screen comprising: introducing a cleanup fluid through a sand control screen and into a portion of a subterranean formation, the sand control screen located in a well bore that penetrates the subterranean formation; applying a pressure pulse to the cleanup fluid; and introducing a consolidating agent through the sand control screen and into the portion of the subterranean formation.

In another embodiment, the present invention provides a method of cleaning a sand control screen and gravel pack comprising: placing a fluidic oscillator in a well bore in a location adjacent to a sand control screen located in the well bore; introducing a cleanup fluid through the fluidic oscillator, through the sand control screen, through a gravel pack, and into a portion of a subterranean formation penetrated by the well bore, wherein the gravel pack is located in an annulus between the sand control screen and the portion of the subterranean formation and wherein a pressure pulse is generated in the cleanup fluid by introducing the cleanup fluid through the fluidic oscillator; and introducing a consolidating agent through the sand control screen, through the gravel pack, and into the portion of the subterranean formation.

The features and advantages of the present invention will be apparent to those skilled in the art. While numerous changes may be made by those skilled in the art, such changes are within the spirit of the invention.

BRIEF DESCRIPTION OF THE DRAWINGS

These drawings illustrate certain aspects of some of the embodiments of the present invention and should not be used to limit or define the invention.

Figure 1 illustrates a cross-sectional, side view of a cased well bore to be treated in accordance with one embodiment of the present invention.

Figure 2 illustrates a cross-sectional, top view taken on line 3-3 of the cased well bore of Figure 1.

Figure 3 illustrates a cross-sectional, side view of the cased well bore of Figure 1 being treated in accordance with one embodiment of the present invention.

Figure 4 illustrates a cross-sectional, side view of an open hole well bore to be treated in accordance with one embodiment of the present invention.

Figure 5 illustrates a cross-sectional, top view taken on line 5-5 of the open hole well bore of Figure 4.

Figure 6 illustrates a cross-sectional, side view of the open hole well bore of Figure 4 being treated in accordance with one embodiment of the present invention.

DESCRIPTION OF PREFERRED EMBODIMENTS

The present invention relates to methods for treating a subterranean environment. More particularly, the present invention relates to the remedial treatment of a subterranean environment with pressure pulsing and consolidating agents. While the methods of the present invention may be useful in a variety of remedial treatments, they may be particularly useful for cleaning sand control equipment (*e.g.*, liners, screens, and the like) and/or gravel packs.

I. Example Methods of the Present Invention

The present invention provides methods for remediating a subterranean environment. An example of such a method comprises: introducing a cleanup fluid through a well bore and into a portion of a subterranean formation penetrated by the well bore; applying a pressure pulse to the cleanup fluid; and introducing a consolidating agent through the well bore and into the portion of the subterranean formation. The methods of the present invention are suitable for use in production and injection wells.

According to the methods of the present invention, a cleanup fluid may be introduced through a well bore and into the portion of the subterranean formation penetrated by the well bore. In some embodiments, an intervening sand control screen, liner, gravel pack, or combination thereof may be located between the well bore and the portion of the subterranean formation. Suitable sand control screens include, but are not limited, to wire-wrapped screens, pre-packed screens, expandable screens, and any other suitable apparatus.

Depending on the formulation of the cleanup fluid, the cleanup fluid may dissolve scale, precipitates, or fines that may be present. In some embodiment the scale and precipitates may be present in the subterranean formation and/or on any sand control screens, liners, and/or gravel packs that may be present. In some embodiments, fines may be located in fluid flow pathways of the subterranean formation and any sand control screens, liners, and/or gravel packs that may be present. These fines located in the fluid flow pathways may impede the flow of fluids there through. Examples of suitable cleanup fluids will be discussed in more detail below.

The methods of the present invention further comprise applying pressure pulses to the cleanup fluid. For example, the cleanup fluid may be introduced into the portion of the subterranean formation through a pulsonic device. Among other things, the pressure pulses should dislodge at least a portion of the fines located in the fluid flow pathways that are impeding the flow of fluids through the subterranean formation, as well as at least a portion of the fines that are located in the fluid flow pathways of any sand control screens, liners, and/or gravel packs that may be present. The cleanup fluid may also move these dislodged fines away from the well bore. Application of the pressure pulse to the cleanup fluid will be discussed in more detail below.

The methods of the present invention further comprise introducing a consolidating agent through the well bore and into the portion of the subterranean formation. Generally, the consolidating agent may be introduced after the step of introducing the cleanup fluid through the well bore and into the portion of the subterranean formation. As used in this disclosure, the term "consolidating agent" refers to a composition that enhances the grain-to-grain (or grain-to-formation) contact between particulates (*e.g.*, proppant particulates, gravel particulates, formation fines, coal fines, etc.) within the subterranean formation so that the particulates are stabilized, locked in place, or at least partially immobilized such that they are resistant to flowing with fluids. When placed into the subterranean formation, the consolidating agent should inhibit the dislodged fines from migrating with any subsequently produced or injected fluids. The consolidating agent may also move these dislodged fines away from the well bore. In some embodiments, a pressure pulse may be applied to the consolidating agent. For example, the consolidating agent may be introduced into the portion of the subterranean formation through a pulsonic device. Examples of suitable consolidating agents will be discussed in more detail below.

According to the methods of the present invention, after placement of the consolidating agent, the subterranean formation optionally may be shut in for a period of time. The shutting in of the well bore for a period of time may, *inter alia*, enhance the coating of the consolidating agent onto the dislodged fines and minimize the washing away of the consolidating agent during later subterranean operations. The necessary shut-in time period is dependent, among other things, on the composition of the consolidating agent used and the temperature of the formation. Generally, the chosen period of time will be between about 0.5 hours and about 72 hours or longer. Determining the proper period of time to shut in the formation is within the ability of one skilled in the art with the benefit of this disclosure.

In some embodiments, introduction of the consolidating agent into the portion of the subterranean formation may result in diminishing the permeability of that portion. Reduction in permeability due to the consolidating agent is based on a variety of factors, including the particular consolidating agent used, the viscosity of the consolidating agent, the volume of the consolidating agent, volume of after-flush treatment fluid, and the pumpability of the formation. In certain embodiments, fracturing a portion of the formation may be required to reconnect the well bore with portions of the formation (*e.g.*, the reservoir formation) outside the portion of the formation treated with the consolidating agent. In other embodiments, *e.g.*, when no fracturing step is used, an after-flush fluid may be used to restore permeability to the portion of the subterranean formation. When used, the after-flush fluid is preferably placed into the subterranean formation while the consolidating agent is still in a flowing state. Among other things, the after-flush fluid acts to displace at least a portion of the consolidating agent from the flow paths in the subterranean formation and to force the displaced portion of the consolidating agent further into the subterranean formation where it may have negligible impact on subsequent hydrocarbon production. Generally, the after-flush fluid may be any fluid that does not adversely react with the other components used in accordance with this invention or with the subterranean formation. For example, the after-flush may be an aqueous-based brine, a hydrocarbon fluid (such as kerosene, diesel, or crude oil), or a gas (such as nitrogen or carbon dioxide). Generally, a substantial amount of the consolidating agent, however, should not be displaced therein. For example, sufficient amounts of the consolidating agent should remain in the treated portion to provide effective stabilization of the unconsolidated portions of the subterranean formation therein.

Referring now to Figures 1 and 2, well bore 100 is shown that penetrates subterranean formation 102. Figure 2 depicts a cross-sectional, top view of well bore 100 taken along line 3-3 of Figure 1. Even though Figure 1 depicts well bore 100 as a vertical well bore, the methods of the present invention may be suitable for use in generally horizontal, generally vertical, or otherwise formed portions of wells. Casing 104 may be located in well bore 100, as shown in Figures 1 and 2 or, in some embodiments, well bore 100 may be open hole. In some embodiments, casing 104 may extend from the ground surface (not shown) into well bore 100. In some embodiments, casing 104 may be connected to the ground surface (not shown) by intervening casing (not shown), such as surface casing and/or conductor pipe. Casing 104 may or may not be cemented to subterranean formation with cement sheath 106. Well bore 100 contains perforations 108 in fluid communication with subterranean formation 102. Perforations 108 extend from well bore 100 into the portion of subterranean formation 102 adjacent thereto. In the cased embodiments, as shown in Figures 1 and 2, perforations 108 extend from well bore 100, through casing 104 and cement sheath 106, and into subterranean formation 102.

A slotted liner 110 comprising an internal sand control screen 112 is located in well bore 100. Annulus 114 is formed between slotted liner 110 and sand control screen 112. Annulus 116 is formed between slotted liner 110 and casing 104. Even though Figures 1 and 2 depict a slotted liner having an internal sand screen, the methods of the present invention may be used with a variety of suitable sand control equipment, including screens, liners (*e.g.*, slotted liners, perforated liners, etc.), combinations of screens and liners, and any other suitable apparatuses. Slotted liner 110 contains slots 118 that may be circular, elongated, rectangular, or any other suitable shape. In some embodiments, fines (not shown) may impede the flow of fluids through slots 118 in slotted liner 110 and/or through sand control screen 112. In some embodiments, scale (not shown) or precipitate (not shown) may be on slotted liner 110 and/or sand control screen 112. Where present, the fines, scale, and/or precipitate may impede the flow of fluids through slots 118 in slotted liner 110 and/or through sand control screen 112.

Gravel pack 120 is located in well bore 100. Gravel pack 120 comprises gravel particulates that have been packed in subterranean formation 102, annulus 114 between slotted liner 110 and sand control screen 112, and annulus 116 between slotted liner 110 and casing 104. In some embodiments, fines (not shown) may be located within the interstitial

spaces of the gravel particulates forming gravel pack 120. In some embodiments, scale (not shown) or precipitate (not shown) may be on gravel pack 120. Where present, the fines, scale, and/or precipitate may impede the flow of fluids through gravel pack 120 by plugging fluid pathways in gravel pack 120.

In accordance with one embodiment of the present invention, a cleanup fluid may be introduced through sand control screen 112, through slots 118 in slotted liner 110, through gravel pack 120, and into subterranean formation 102. A pressure pulse should be applied to cleanup fluid while it is introduced. Depending on the formulation of the cleanup fluid, the cleanup fluid may dissolve scale, precipitates, or fines that may be present. Among other things, the pressure pulses should dislodge fines that are impeding the flow of fluids through subterranean formation 102, sand control screen 112, slots 118 in slotted liner 110, and/or gravel pack 120. The cleanup fluid should carry these dislodged fines away from well bore 100. Subsequent to the introduction of the cleanup fluid, a consolidating agent may be introduced through sand control screen 112, through slots 118 in slotted liner 110, through gravel pack 120, and into subterranean formation 102. A portion of the consolidating agent may remain in gravel pack 120. The consolidating agent should inhibit the dislodged fines that have been moved away from the well bore from migrating with any subsequently produced fluids.

Referring now to Figure 3, well bore 100 is shown being treated in accordance with one embodiment of the present invention. Pulsonic device 322 may be placed in well bore 100 on pipe string 324. Pipe string 324 may comprise coiled tubing, jointed pipe, or any other suitable apparatus suitable to position pulsonic device 322 in well bore 100. The pulsonic device 322 may be placed in well bore 100 adjacent to the portion of subterranean formation 102 to be treated. The cleanup fluid may be flowed into pipe string 324, through pulsonic device 322, through sand control screen 112, through slots 118 in slotted liner 110, through gravel pack 120, and into subterranean formation 102. A pressure pulse is applied to the cleanup fluid by flowing the cleanup fluid through pulsonic device 322. Subsequent to the introduction of the cleanup fluid into subterranean formation 102, a consolidating agent may be introduced through sand control screen 112, through slots 118 in slotted liner 110, through gravel pack 120, and into subterranean formation 102. In some embodiments, a pressure pulse may be applied to the consolidating agent by flowing the consolidating agent into pipe string 324 and through pulsonic device 322.

Referring now to Figures 4 and 5, well bore 400 that has been completed open hole is illustrated. Figure 5 depicts a cross-sectional, top view of well bore 400 taken along line 5-5 of Figure 4. Well bore 400 penetrates subterranean formation 402. Even though Figure 4 depicts well bore 400 as a vertical well bore, the methods of the present invention may be suitable for use in generally horizontal, generally vertical, or otherwise formed portions of wells. Sand control screen 404 is shown located in well bore 400. Even though Figures 4 and 5 depict a sand control screen, the methods of the present invention may be used with any suitable sand control equipment, including screens, liners (*e.g.*, slotted liners, perforated liners, etc.), combinations of screens and liners, and any other suitable apparatus. Sand control screen 404 may be a wire-wrapped screen, a pre-packed screen, an expandable screen, or any other suitable sand control screen. Annulus 406 is formed between sand control screen 404 and an interior wall of well bore 400. In some embodiments, fines (not shown) may impede the flow of fluids through sand control screen 404. In some embodiments, scale (not shown) or precipitate (not shown) may be on sand control screen 404. Where present, the fines, scale, and/or precipitate may impede the flow of fluids through sand control screen 404.

Gravel pack 408 is located in well bore 400. Gravel pack 408 comprises gravel particulates that have been packed in annulus 406 between sand control screen 404 and the interior wall of well bore 400. In some embodiments, fines (not shown) may be located within the interstitial spaces of the gravel particulates forming gravel pack 408. In some embodiments, scale (not shown) or precipitate (not shown) may be on gravel pack 408. Where present, the fines, scale, and/or precipitate may impede the flow of fluids through gravel pack 408 by plugging fluid pathways in gravel pack 408.

In accordance with one embodiment of the present invention, a cleanup fluid may be introduced through sand control screen 404, through gravel pack 408, and into subterranean formation 402. A pressure pulse should be applied to cleanup fluid while it is introduced. Depending on the formulation of the cleanup fluid, the cleanup fluid may dissolve scale, precipitates, or fines that may be present. Among other things, the pressure pulses should dislodge fines that are impeding the flow of fluids through subterranean formation 402, sand control screen 404, and gravel pack 408. The cleanup fluid should carry these dislodged fines away from well bore 400. Subsequent to the introduction of the cleanup fluid, a consolidating agent may be introduced through sand control screen 404, through gravel pack

408, and into subterranean formation 402. A thin coating of the consolidating agent may remain on the gravel particulates of the gravel pack 408. The consolidating agent should inhibit the dislodged fines that have been moved away from well bore 400 from migrating with any subsequently produced fluids.

Referring now to Figure 6, well bore 400 is shown being treated in accordance with one embodiment of the present invention. Pulsonic device 610 may be placed in well bore 400 on pipe string 612. Pipe string 612 may comprise coiled tubing, jointed pipe, or any other suitable apparatus suitable to position pulsonic device 610 in well bore 400. The pulsonic device 610 may be placed in well bore 400 adjacent to sand control screen 404. The cleanup fluid may be flowed into pipe string 612, through pulsonic device 610, through sand control screen 404, through gravel pack 408, and into subterranean formation 402. A pressure pulse is applied to the cleanup fluid by flowing the cleanup fluid through pulsonic device 610. Subsequent to the introduction of the cleanup fluid into subterranean formation 402, a consolidating agent may be introduced through sand control screen 404, through gravel pack 408, and into subterranean formation 402. In some embodiments, a pressure pulse may be applied to the consolidating agent by flowing the consolidating agent into pipe string 612 and through pulsonic device 610.

II. Pressure Pulse

Any suitable apparatus and/or methodology for applying a pressure pulse to the cleanup fluid may be suitable for use in the present invention. In some embodiments, a pressure pulse also may be applied to the consolidating agent. Generally, the pressure pulse should be sufficient to provide the desired movement of fines without fracturing the portion of the subterranean formation.

Pressure pulsing generally generates a pressure (or vibrational) wave in the fluid (*e.g.*, the cleanup fluid or the consolidating agent) as it is being introduced into the subterranean formation. The pressure pulse may be applied to the fluid at the surface or in the well bore. In some embodiments, the frequency of the pressure pulses applied to the fluid may be in the range of from about 0.001 Hz to about 1 Hz. In some embodiments, the pressure pulse applied to the fluid may generate a pressure pulse in the portion of the subterranean formation in the range of from about 10 psi to about 3,000 psi

In addition to generating pressure waves that act to dislodge fines, the pressure pulse also affects the dilatancy of the pores within the formation, among other things, to provide

additional energy that may help overcome the effects of surface tension and capillary pressure within the formation. As the pressure wave passes through the formation and is reflected back, the pressure wave induces dilation in the porosity of the formation. By overcoming such effects, the fluid may be able to penetrate more deeply and uniformly into the formation. The pressure pulse should be sufficient to affect some degree of pore dilation within the formation, but should be less than the fracture pressure of the formation. Generally, the use of high frequency, low amplitude pressure pulses will focus energy primarily in the near well bore region, while low frequency, high amplitude pressure pulses may be used to achieve deeper penetration.

In some embodiments, the pressure pulse may be generated by flowing the fluid through a pulsonic device, such as a fluidic oscillator. For example, the fluidic oscillator may be placed into the well bore on tubing (e.g., coiled tubing) or jointed pipe. Once the fluidic oscillator has been placed at the desired location in the well bore, the fluid may be flowed through the fluidic oscillator to generate the desired pressure pulsing in the fluid. Generally, the fluid may be flowed through the fluidic oscillator at a constant rate and/or pressure and the pressure pulse is applied to the fluid as it passes through the fluidic oscillator. Examples of suitable fluidic oscillators are provided in U.S. Patent Numbers 5,135,051; 5,165,438; and 5,893,383, and in U.S. Patent Application PG Publication No. 2004/0256099.

III. Example Cleanup Fluids

The cleanup fluid is introduced through the well bore and into the subterranean formation. A pressure pulse is also applied to the cleanup fluid. In some embodiments, the cleanup fluid comprises an aqueous fluid. In some embodiments, the cleanup fluid further may comprise an acid, a scale inhibitor, a corrosion inhibitor, or combinations thereof.

Aqueous fluids that may be used in the cleanup fluids useful in the methods of the present invention include, but are not limited to, freshwater, saltwater (e.g., water containing one or more salts dissolved therein), brine (e.g., saturated saltwater produced from subterranean formations), seawater, or combinations thereof. Generally, the aqueous fluid may be from any source, provided that it does not contain an excess of compounds that may adversely affect other components in the cement composition.

The cleanup fluids useful in the methods of the present invention further may comprise an acid. Among other things, the acid may dissolve scale, precipitates, and/or fines that may be present in the subterranean formation. Examples of suitable acids include organic (*e.g.*, acetic acids or formic acids) and mineral acids (*e.g.*, hydrochloric acid or hydrofluoric acid). The concentration of the acid included in the cleanup fluid will vary based on a number of factors including, the particular acid used, the particular application, well bore conditions, and the other factors known to those of ordinary skill in the art, with the benefit of this disclosure.

The cleanup fluids useful in the methods of the present invention further may comprise a scale inhibitor. Among other things, a scale inhibitor may be included in the cleanup fluids to control and/or inhibit the formation of scale in the subterranean formation. Examples of suitable scale inhibitors include, but are not limited to, phosphonates (*e.g.*, diethylenetriamine penta(methylene) phosphonic acid, polyphosphino-carboxylic acids, and polylmers, such as poly acrylate and poly vinyl sulphonate), sulphonated polyacrylates, phosphonomethylated polyamines, and combinations thereof.

Corrosion inhibitors also may be included in the cleanup fluids. A corrosion inhibitor may be included in the cleanup fluid, for example, when an acid is included in the cleanup fluid.

IV. Example Consolidating Agents

Suitable consolidating agents may comprise non-aqueous tackifying agents, aqueous tackifying agents, resins, gelable compositions, and combinations thereof. As used in this disclosure, the term "tacky," in all of its forms, generally refers to a substance having a nature such that it is (or may be activated to become) somewhat sticky to the touch. In some embodiments, the consolidation agent may have a viscosity in the range of from about 1 centipoise ("cP") to about 100 cP. In some embodiments, the consolidation agent may have a viscosity in the range of from about 1 cP to 50 cP. In some embodiments, the consolidation agent may have a viscosity in the range of from about 1 cP about 10 cP. In some embodiments, the consolidation agent may have a viscosity in the range of from about 1 cP about 5 cP. For the purposes of this disclosure, viscosities are measured at room temperature using a Brookfield DV II+ Viscometer with a #1 spindle at 100 rpm. The viscosity of the consolidating agent should be sufficient to have the desired penetration into the subterranean

formation and coating onto the dislodged fines based on a number of factors, including the pumpability of the formation and the desired depth of penetration.

A. Non-Aqueous Tackifying Agents

In some embodiments, the consolidation agents may comprise a non-aqueous tackifying agent. Non-aqueous tackifying agents suitable for use in the consolidating agents of the present invention comprise any compound that, when in liquid form or in a solvent solution, will form a non-hardening coating upon a particulate. A particularly preferred group of non-aqueous tackifying agents comprise polyamides that are liquids or in solution at the temperature of the subterranean formation such that they are, by themselves, non-hardening when 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 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, 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 agents include liquids and solutions of, for example, polyesters, polycarbonates and polycarbamates, natural resins such as shellac and the like. Other suitable tackifying agents are described in U.S. Patent Numbers 5,853,048 and 5,833,000.

Non-aqueous tackifying agents suitable for use in the present invention may be either used such that they form non-hardening coating or they may be combined with a multifunctional material capable of reacting with the tackifying compound to form a hardened coating. A "hardened coating" as used in this disclosure means that the reaction of the tackifying compound with the multifunctional material will result in a substantially non-flowable reaction product that exhibits a higher compressive strength in a consolidated agglomerate than the tackifying compound alone with the particulates. In this instance, the tackifying agent may function similarly to a hardenable resin. Multifunctional materials suitable for use in the present invention include, but are not limited to, aldehydes such as formaldehyde, dialdehydes such as glutaraldehyde, hemiacetals or aldehyde releasing

compounds, diacid halides, dihalides such as dichlorides and dibromides, polyacid anhydrides such as citric acid, epoxides, furfuraldehyde, glutaraldehyde or aldehyde condensates and the like, and combinations thereof. In some embodiments of the present invention, the multifunctional material may be mixed with the tackifying agent in an amount of from about 0.01 to about 50 percent by weight of the tackifying agent to effect formation of the reaction product. In some preferable embodiments, the compound is present in an amount of from about 0.5 to about 1 percent by weight of the tackifying agent. Suitable multifunctional materials are described in U.S. Patent No. 5,839,510.

In some embodiments, the consolidating agent may comprise a non-aqueous tackifying agent and a solvent. Solvents suitable for use with the non-aqueous tackifying agents of the present invention include any solvent that is compatible with the non-aqueous tackifying agent and achieves the desired viscosity effect. The solvents that can be used in the present invention preferably include those having high flash points (most preferably above about 125°F.). Examples of solvents suitable for use in the present invention include, but are not limited to, butylglycidyl ether, dipropylene glycol methyl ether, butyl bottom alcohol, dipropylene glycol dimethyl ether, diethyleneglycol methyl ether, ethyleneglycol butyl ether, methanol, butyl alcohol, isopropyl alcohol, diethyleneglycol butyl ether, propylene carbonate, d'limonene, 2-butoxy ethanol, butyl acetate, furfuryl acetate, butyl lactate, dimethyl sulfoxide, dimethyl formamide, fatty acid methyl esters, and combinations thereof. It is within the ability of one skilled in the art, with the benefit of this disclosure, to determine whether a solvent is needed to achieve a viscosity suitable to the subterranean conditions and, if so, how much.

B. Aqueous Tackifying Agents

In some embodiment, the consolidation agent may comprise an aqueous tackifying agent. As used in this disclosure, the term "aqueous tackifying agent" refers to a tackifying agent that is soluble in water. Where an aqueous tackifying agent is used, the consolidation agent generally further comprises an aqueous liquid.

Suitable aqueous tackifying agents of the present invention generally comprise charged polymers that, when in an aqueous solvent or solution, will form a non-hardening coating (by itself or with an activator) and, when placed on a particulate, will increase the continuous critical resuspension velocity of the particulate when contacted by a stream of

water. The aqueous tackifying agent enhances the grain-to-grain contact between the individual particulates within the formation (e.g., proppant particulates, gravel particulates, formation particulates, or other particulates), and may help bring about the consolidation of the particulates into a cohesive, flexible, and permeable mass. Some suitable aqueous tackifying agents are described below, but additional detail on suitable materials can be found in U.S. Patent Publication No. 2005/0277554 A1 and U.S. Patent Number 7,131,491.

Examples of aqueous tackifying agents suitable for use in the present invention include, but are not limited to, acrylic acid polymers, acrylic acid ester polymers, acrylic acid derivative polymers, acrylic acid homopolymers, acrylic acid ester homopolymers (such as poly(methyl acrylate), poly(butyl acrylate), and poly(2-ethylhexyl acrylate)), acrylic acid ester co-polymers, methacrylic acid derivative polymers, methacrylic acid homopolymers, methacrylic acid ester homopolymers (such as poly(methyl methacrylate), poly(butyl methacrylate), and poly(2-ethylhexyl methacryate)), acrylamido-methyl-propane sulfonate polymers, acrylamido-methyl-propane sulfonate derivative polymers, acrylamido-methyl-propane sulfonate co-polymers, and acrylic acid/acrylamido-methyl-propane sulfonate co-polymers and combinations thereof. In particular embodiments, the aqueous tackifying agent comprises a polyacrylate ester available from Halliburton Energy Services, Inc., of Duncan, Oklahoma. In some embodiments, the aqueous tackifying agent is included in the consolidating agent in an amount of from about 0.1% to about 40% by weight of the consolidating agent. In some embodiments the aqueous tackifying agent is included in the consolidating agent in an amount of from about 2% to about 30% by weight of the consolidating agent.

In some embodiments, the aqueous tackifying agent may be substantially tacky until activated (e.g., destabilized, coalesced, and/or reacted) to transform the agent into a sticky, tackifying compound at a desired term. In certain embodiments, the consolidating agents of the present invention further may comprise an activator to activate (i.e., tackify) the aqueous tackifying agent. Suitable activators include organic acids, anhydrides of organic acids that are capable of hydrolyzing in water to create organic acids, inorganic acids, inorganic salt solutions (e.g., brines), charged surfactants, charged polymers, and combinations thereof. However, any substance that is capable of making the aqueous tackifying agent insoluble in an aqueous solution may be used as an activator in accordance with the teachings of the

present invention. The choice of an activator may vary, depending on, *inter alia*, the choice of aqueous tackifying agent. In certain embodiments, the concentration of salts present in the formation water itself may be sufficient to activate the aqueous tackifying agent. In such an embodiment it may not be necessary include an activator in the consolidating agent.

Examples of suitable organic acids that may be used as an activator include acetic acid, formic acid, and combinations thereof. In some embodiments, the activator may comprise a mixture of acetic and acetic anhydrides. Where an organic acid is used, in certain embodiments, the activation process may be analogous to coagulation. For example, many natural rubber latexes may be coagulated with acetic or formic acid during the manufacturing process.

Suitable inorganic salts that may be included in the inorganic salts solutions that may be used as an activator may comprise sodium chloride, potassium chloride, calcium chloride, or mixtures thereof.

Generally, where used, the activator may be present in an amount sufficient to provide the desired activation of the aqueous tackifying agent. In some embodiments, the activator may be present in the consolidating agents of the present invention in an amount in the range of from about 1% to about 40% by weight of the consolidating agent. However, in some embodiments, for example where an inorganic salt solution is used, the activator may be present in greater amounts. The amount of activator present in the aqueous tackifying agent may depend on, *inter alia*, the amount of aqueous tackifying agent present and/or the desired rate of reaction. Additional information on suitable materials may be found in United States Patent Publication Number 2005/0277554 A1 and U.S. Patent No. 7,131,491.

Generally, where an aqueous tackifying agent is used, the consolidating agent further comprises an aqueous liquid. The aqueous liquid present in the consolidating agent may be freshwater, saltwater, seawater, or brine, provided the salinity of the water source does not undesirably activate the aqueous tackifying agents used in the present invention. In some embodiments, the aqueous liquid may be present in an amount in the range of from about 0.1% to about 98% by weight of the consolidating agent.

In some embodiments, the consolidating agent further may comprise a surfactant. Where used, the surfactant may facilitate the coating of an aqueous tackifying agent onto particulates, such as those in a particulate bed and/or formation fines being treated.

Typically, the aqueous tackifying agents of the present invention preferentially attach to particulates having an opposite charge. For instance, an aqueous tackifying agent having a negative charge should preferentially attach to surfaces having a positive to neutral zeta potential and/or a hydrophobic surface. Similarly, positively-charged aqueous tackifying agent should preferentially attach to negative to neutral zeta potential and/or a hydrophilic surfaces. Therefore, in some embodiments of the present invention, a cationic surfactant may be included in the consolidating agent to facilitate the application of the negatively-charged aqueous tackifying agent to a particulate having a negative zeta potential. As will be understood by one skilled in the art, amphoteric and zwitterionic surfactants and combinations thereof may also be used so long as the conditions they are exposed to during use are such that they display the desired charge. For example, in some embodiments, mixtures of cationic and amphoteric surfactants may be used. Any surfactant compatible with the aqueous tackifying agent may be used in the present invention. Such surfactants include, but are not limited to, ethoxylated nonyl phenol phosphate esters, mixtures of one or more cationic surfactants, one or more non-ionic surfactants, and an alkyl phosphonate surfactant. Suitable mixtures of one or more cationic and nonionic surfactants are described in U.S. Patent No. 6,311,773. In some embodiments, a C_{12}-C_{22} alkyl phosphonate surfactant may be used. In some embodiments, the surfactant may be present in the consolidating agent in an amount in the range of from about 0.1% to about 15% by weight of the consolidating agent. In some embodiments, the surfactant may be present in an amount of from about 1% to about 5% by weight of the consolidating agent.

In some embodiments, where an aqueous tackifying agent is used, the consolidating agent further may comprise a solvent. Such a solvent may be used, among other things, to reduce the viscosity of the consolidating agent where desired. In embodiments using a solvent, it is within the ability of one skilled in the art, with the benefit of this disclosure, to determine how much solvent is needed to achieve a viscosity suitable to the subterranean conditions. Any solvent that is compatible with the aqueous tackifying agent and achieves the desired viscosity effects is suitable for use in the present invention. The solvents that can be used in the present invention preferably include those having high flash points (most preferably above about 125°F.). Examples of some solvents suitable for use in the present invention include, but are not limited to, water, butylglycidyl ether, dipropylene glycol

methyl ether, butyl bottom alcohol, dipropylene glycol dimethyl ether, diethyleneglycol methyl ether, ethyleneglycol butyl ether, diethyleneglycol butyl ether, propylene carbonate, butyl lactate, dimethyl sulfoxide, dimethyl formamide, fatty acid methyl esters, and combinations thereof.

C. Resins

In some embodiment, the consolidating agent may comprise a resin. "Resin," as used in this disclosure, refers to any of numerous physically similar polymerized synthetics or chemically modified natural resins including thermoplastic materials and thermosetting materials. Suitable resins include both curable and non-curable resins. Curable resins suitable for use in the consolidating agents of the present invention include any resin capable of forming a hardened, consolidated mass. Whether a particular resin is curable or non-curable depends on a number of factors, including molecular weight, temperature, resin chemistry, and a variety of other factors known to those of ordinary skill in the art.

Suitable resins include, but are not limited to, two component epoxy based resins, novolak resins, polyepoxide resins, phenol-aldehyde resins, urea-aldehyde resins, urethane resins, phenolic resins, furan resins, furan/furfuryl alcohol resins, phenolic/latex resins, phenol formaldehyde resins, polyester resins and hybrids and copolymers thereof, polyurethane resins and hybrids and copolymers thereof, acrylate resins, and mixtures thereof. Some suitable resins, such as epoxy resins, may be cured with an internal catalyst or activator so that when pumped down hole, they may be cured using only time and temperature. Other suitable resins, such as furan resins generally require a time-delayed catalyst or an external catalyst to help activate the polymerization of the resins if the cure temperature is low (*i.e.*, less than 250 °F), but will cure under the effect of time and temperature if the formation temperature is above about 250°F, preferably above about 300°F. It is within the ability of one skilled in the art, with the benefit of this disclosure, to select a suitable resin for use in embodiments of the present invention and to determine whether a catalyst is required to trigger curing.

In some embodiments, the consolidating agent comprises a resin and a solvent. Any solvent that is compatible with the resin and achieves the desired viscosity effect is suitable for use in the present invention. Preferred solvents include those listed above in connection with the nonaqueous tackifying compounds. 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.

D. Gelable Compositions

In some embodiments, the consolidating agents comprise a gelable composition. Gelable compositions suitable for use in the present invention include those compositions that cure to form a semi-solid, immovable, gel-like substance. The gelable composition may be any gelable liquid composition capable of converting into a gelled substance capable of substantially plugging the permeability of the formation while allowing the formation to remain flexible. As referred to in this disclosure, the term "flexible" refers to a state wherein the treated formation is relatively malleable and elastic and able to withstand substantial pressure cycling without substantial breakdown of the formation. Thus, the resultant gelled substance stabilizes the treated portion of the formation while allowing the formation to absorb the stresses created during pressure cycling. As a result, the gelled substance may aid in preventing breakdown of the formation both by stabilizing and by adding flexibility to the treated region. Examples of suitable gelable liquid compositions include, but are not limited to, (1) gelable resin compositions, (2) gelable aqueous silicate compositions, (3) crosslinkable aqueous polymer compositions, and (4) polymerizable organic monomer compositions.

1. Gelable Resin Compositions

Certain embodiments of the gelable liquid compositions of the present invention comprise gelable resin compositions that cure to form flexible gels. Unlike the curable resins described above, which cure into hardened masses, the gelable resin compositions cure into flexible, gelled substances that form resilient gelled substances. Gelable resin compositions allow the treated portion of the formation to remain flexible and to resist breakdown. Generally, the gelable resin compositions useful in accordance with this invention comprise a curable resin, a diluent, and a resin curing agent. When certain resin curing agents, such as polyamides, are used in the curable resin compositions, the compositions form the semi-solid, immovable, gelled substances described above. Where the resin curing agent used may cause the organic resin compositions to form hard, brittle material rather than a desired gelled substance, the curable resin compositions may further comprise one or more "flexibilizer additives" (described in more detail below) to provide flexibility to the cured compositions.

Examples of gelable resins that can be used in the present invention include, but are not limited to, organic resins such as polyepoxide resins (e.g., Bisphenol a-epichlorihydrin resins), polyester resins, urea-aldehyde resins, furan resins, urethane resins, and mixtures thereof. Of these, polyepoxide resins are preferred.

Any solvent that is compatible with the gelable resin and achieves the desired viscosity effect is suitable for use in the present invention. Examples of solvents that may be used in the gelable resin compositions of the present invention include, but are not limited to, phenols; formaldehydes; furfuryl alcohols; furfurals; alcohols; ethers such as butyl glycidyl ether and cresyl glycidyl etherphenyl glycidyl ether; and mixtures thereof. In some embodiments of the present invention, the solvent comprises butyl lactate. Among other things, the solvent acts to provide flexibility to the cured composition. The solvent may be included in the gelable resin composition in an amount sufficient to provide the desired viscosity effect.

Generally, any resin curing agent that may be used to cure an organic resin is suitable for use in the present invention. When the resin curing agent chosen is an amide or a polyamide, generally no flexibilizer additive will be required because, *inter alia*, such curing agents cause the gelable resin composition to convert into a semi-solid, immovable, gelled substance. Other suitable resin curing agents (such as an amine, a polyamine, methylene dianiline, and other curing agents known in the art) will tend to cure into a hard, brittle material and will thus benefit from the addition of a flexibilizer additive. Generally, the resin curing agent used is included in the gelable resin composition, whether a flexibilizer additive is included or not, in an amount in the range of from about 5% to about 75% by weight of the curable resin. In some embodiments of the present invention, the resin curing agent used is included in the gelable resin composition in an amount in the range of from about 20% to about 75% by weight of the curable resin.

As noted above, flexibilizer additives may be used, *inter alia*, to provide flexibility to the gelled substances formed from the curable resin compositions. Flexibilizer additives may be used where the resin curing agent chosen would cause the gelable resin composition to cure into a hard and brittle material – rather than a desired gelled substance. For example, flexibilizer additives may be used where the resin curing agent chosen is not an amide or polyamide. Examples of suitable flexibilizer additives include, but are not limited to, an organic ester, an oxygenated organic solvent, an aromatic solvent, and combinations thereof.

Of these, ethers, such as dibutyl phthalate, are preferred. Where used, the flexibilizer additive may be included in the gelable resin composition in an amount in the range of from about 5% to about 80% by weight of the gelable resin. In some embodiments of the present invention, the flexibilizer additive may be included in the curable resin composition in an amount in the range of from about 20% to about 45% by weight of the curable resin.

2. Gelable Aqueous Silicate Compositions

In some embodiments, the consolidating agents of the present invention may comprise a gelable aqueous silicate composition. Generally, the gelable aqueous silicate compositions that are useful in accordance with the present invention generally comprise an aqueous alkali metal silicate solution and a temperature activated catalyst for gelling the aqueous alkali metal silicate solution.

The aqueous alkali metal silicate solution component of the gelable aqueous silicate compositions generally comprise an aqueous liquid and an alkali metal silicate. The aqueous liquid component of the aqueous alkali metal silicate solution generally may be fresh water, salt water (*e.g.*, water containing one or more salts dissolved therein), brine (*e.g.*, saturated salt water), seawater, or any other aqueous liquid that does not adversely react with the other components used in accordance with this invention or with the subterranean formation. Examples of suitable alkali metal silicates include, but are not limited to, one or more of sodium silicate, potassium silicate, lithium silicate, rubidium silicate, or cesium silicate. Of these, sodium silicate is preferred. While sodium silicate exists in many forms, the sodium silicate used in the aqueous alkali metal silicate solution preferably has a Na_2O-to-SiO_2 weight ratio in the range of from about 1:2 to about 1:4. Most preferably, the sodium silicate used has a Na_2O-to-SiO_2 weight ratio in the range of about 1:3.2. Generally, the alkali metal silicate is present in the aqueous alkali metal silicate solution component in an amount in the range of from about 0.1% to about 10% by weight of the aqueous alkali metal silicate solution component.

The temperature-activated catalyst component of the gelable aqueous silicate compositions is used, *inter alia*, to convert the gelable aqueous silicate compositions into the desired semi-solid, immovable, gelled substance described above. Selection of a temperature-activated catalyst is related, at least in part, to the temperature of the subterranean formation to which the gelable aqueous silicate composition will be introduced. The temperature-activated catalysts that can be used in the gelable aqueous silicate

compositions of the present invention include, but are not limited to, ammonium sulfate (which is most suitable in the range of from about 60°F to about 240°F); sodium acid pyrophosphate (which is most suitable in the range of from about 60°F to about 240°F); citric acid (which is most suitable in the range of from about 60°F to about 120°F); and ethyl acetate (which is most suitable in the range of from about 60°F to about 120°F). Generally, the temperature-activated catalyst is present in the gelable aqueous silicate composition in the range of from about 0.1% to about 5% by weight of the gelable aqueous silicate composition.

3. Crosslinkable Aqueous Polymer Compositions

In other embodiments, the consolidating agent of the present invention comprises a crosslinkable aqueous polymer compositions. Generally, suitable crosslinkable aqueous polymer compositions comprise an aqueous solvent, a crosslinkable polymer, and a crosslinking agent. Such compositions are similar to those used to form gelled treatment fluids, such as fracturing fluids, but, according to the methods of the present invention, they are not exposed to breakers or de-linkers and so they retain their viscous nature over time.

The aqueous solvent may be any aqueous solvent in which the crosslinkable composition and the crosslinking agent may be dissolved, mixed, suspended, or dispersed therein to facilitate gel formation. For example, the aqueous solvent used may be fresh water, salt water, brine, seawater, or any other aqueous liquid that does not adversely react with the other components used in accordance with this invention or with the subterranean formation.

Examples of crosslinkable polymers that can be used in the crosslinkable aqueous polymer compositions include, but are not limited to, carboxylate-containing polymers and acrylamide-containing polymers. Preferred acrylamide-containing polymers include polyacrylamide, partially hydrolyzed polyacrylamide, copolymers of acrylamide and acrylate, and carboxylate-containing terpolymers and tetrapolymers of acrylate. Additional examples of suitable crosslinkable polymers include hydratable polymers comprising polysaccharides and derivatives thereof and that contain one or more of the monosaccharide units galactose, mannose, glucoside, glucose, xylose, arabinose, fructose, glucuronic acid, or pyranosyl sulfate. Suitable natural hydratable polymers include, but are not limited to, guar gum, locust bean gum, tara, konjak, tamarind, starch, cellulose, karaya, xanthan, tragacanth, and carrageenan, and derivatives of all of the above. Suitable hydratable synthetic polymers and copolymers that may be used in the crosslinkable aqueous polymer compositions include, but are not limited to, polyacrylates, polymethacrylates, polyacrylamides, maleic anhydride,

methylvinyl ether polymers, polyvinyl alcohols, and polyvinylpyrrolidone. The crosslinkable polymer used should be included in the crosslinkable aqueous polymer composition in an amount sufficient to form the desired gelled substance in the subterranean formation. In some embodiments of the present invention, the crosslinkable polymer is included in the crosslinkable aqueous polymer composition in an amount in the range of from about 1% to about 30% by weight of the aqueous solvent. In another embodiment of the present invention, the crosslinkable polymer is included in the crosslinkable aqueous polymer composition in an amount in the range of from about 1% to about 20% by weight of the aqueous solvent.

The crosslinkable aqueous polymer compositions of the present invention further comprise a crosslinking agent for crosslinking the crosslinkable polymers to form the desired gelled substance. In some embodiments, the crosslinking agent is a molecule or complex containing a reactive transition metal cation. A most preferred crosslinking agent comprises trivalent chromium cations complexed or bonded to anions, atomic oxygen, or water. Examples of suitable crosslinking agents include, but are not limited to, compounds or complexes containing chromic acetate and/or chromic chloride. Other suitable transition metal cations include chromium VI within a redox system, aluminum III, iron II, iron III, and zirconium IV.

The crosslinking agent should be present in the crosslinkable aqueous polymer compositions of the present invention in an amount sufficient to provide, *inter alia*, the desired degree of crosslinking. In some embodiments of the present invention, the crosslinking agent is present in the crosslinkable aqueous polymer compositions of the present invention in an amount in the range of from about 0.01% to about 5% by weight of the crosslinkable aqueous polymer composition. The exact type and amount of crosslinking agent or agents used depends upon the specific crosslinkable polymer to be crosslinked, formation temperature conditions, and other factors known to those individuals skilled in the art.

Optionally, the crosslinkable aqueous polymer compositions may further comprise a crosslinking delaying agent, such as a polysaccharide crosslinking delaying agent derived from guar, guar derivatives, or cellulose derivatives. The crosslinking delaying agent may be included in the crosslinkable aqueous polymer compositions, *inter alia*, to delay crosslinking of the crosslinkable aqueous polymer compositions until desired. One of ordinary skill in the

art, with the benefit of this disclosure, will know the appropriate amount of the crosslinking delaying agent to include in the crosslinkable aqueous polymer compositions for a desired application.

4. Polymerization Organic Monomer Compositions

In other embodiments, the gelled liquid compositions of the present invention comprise polymerizable organic monomer compositions. Generally, suitable polymerizable organic monomer compositions comprise an aqueous-base fluid, a water-soluble polymerizable organic monomer, an oxygen scavenger, and a primary initiator.

The aqueous-based fluid component of the polymerizable organic monomer composition generally may be fresh water, salt water, brine, seawater, or any other aqueous liquid that does not adversely react with the other components used in accordance with this invention or with the subterranean formation.

A variety of monomers are suitable for use as the water-soluble polymerizable organic monomers in the present invention. Examples of suitable monomers include, but are not limited to, acrylic acid, methacrylic acid, acrylamide, methacrylamide, 2-methacrylamido-2-methylpropane sulfonic acid, 2-dimethylacrylamide, vinyl sulfonic acid, N,N-dimethylaminoethylmethacrylate, 2-triethylammoniumethylmethacrylate chloride, N,N-dimethyl-aminopropylmethacryl-amide, methacrylamidepropyltriethylammonium chloride, N-vinyl pyrrolidone, vinyl-phosphonic acid, and methacryloyloxyethyl trimethylammonium sulfate, and mixtures thereof. Preferably, the water-soluble polymerizable organic monomer should be self-crosslinking. Examples of suitable monomers which are self crosslinking include, but are not limited to, hydroxyethylacrylate, hydroxymethylacrylate, hydroxyethylmethacrylate, N-hydroxymethylacrylamide, N-hydroxymethyl-methacrylamide, polyethylene glycol acrylate, polyethylene glycol methacrylate, polypropylene glycol acrylate, polypropylene glycol methacrylate, and mixtures thereof. Of these, hydroxyethylacrylate is preferred. An example of a particularly preferable monomer is hydroxyethylcellulose-vinyl phosphoric acid.

The water-soluble polymerizable organic monomer (or monomers where a mixture thereof is used) should be included in the polymerizable organic monomer composition in an amount sufficient to form the desired gelled substance after placement of the polymerizable organic monomer composition into the subterranean formation. In some embodiments of the present invention, the water-soluble polymerizable organic monomer is included in the

polymerizable organic monomer composition in an amount in the range of from about 1% to about 30% by weight of the aqueous-base fluid. In another embodiment of the present invention, the water-soluble polymerizable organic monomer is included in the polymerizable organic monomer composition in an amount in the range of from about 1% to about 20% by weight of the aqueous-base fluid.

The presence of oxygen in the polymerizable organic monomer composition may inhibit the polymerization process of the water-soluble polymerizable organic monomer or monomers. Therefore, an oxygen scavenger, such as stannous chloride, may be included in the polymerizable monomer composition. In order to improve the solubility of stannous chloride so that it may be readily combined with the polymerizable organic monomer composition on the fly, the stannous chloride may be pre-dissolved in a hydrochloric acid solution. For example, the stannous chloride may be dissolved in a 0.1% by weight aqueous hydrochloric acid solution in an amount of about 10% by weight of the resulting solution. The resulting stannous chloride-hydrochloric acid solution may be included in the polymerizable organic monomer composition in an amount in the range of from about 0.1% to about 10% by weight of the polymerizable organic monomer composition. Generally, the stannous chloride may be included in the polymerizable organic monomer composition of the present invention in an amount in the range of from about 0.005% to about 0.1% by weight of the polymerizable organic monomer composition.

The primary initiator is used, *inter alia*, to initiate polymerization of the water-soluble polymerizable organic monomer(s) used in the present invention. Any compound or compounds that form free radicals in aqueous solution may be used as the primary initiator. The free radicals act, *inter alia*, to initiate polymerization of the water-soluble polymerizable organic monomer present in the polymerizable organic monomer composition. Compounds suitable for use as the primary initiator include, but are not limited to, alkali metal persulfates; peroxides; oxidation-reduction systems employing reducing agents, such as sulfites in combination with oxidizers; and azo polymerization initiators. Preferred azo polymerization initiators include 2,2'-azobis(2-imidazole-2-hydroxyethyl) propane, 2,2'-azobis(2-aminopropane), 4,4'-azobis(4-cyanovaleric acid), and 2,2'-azobis(2-methyl-N-(2-hydroxyethyl) propionamide. Generally, the primary initiator should be present in the polymerizable organic monomer composition in an amount sufficient to initiate polymerization of the water-soluble polymerizable organic monomer(s). In certain

embodiments of the present invention, the primary initiator is present in the polymerizable organic monomer composition in an amount in the range of from about 0.1% to about 5% by weight of the water-soluble polymerizable organic monomer(s). One skilled in the art will recognize that as the polymerization temperature increases, the required level of activator decreases.

Optionally, the polymerizable organic monomer compositions further may comprise a secondary initiator. A secondary initiator may be used, for example, where the immature aqueous gel is placed into a subterranean formation that is relatively cool as compared to the surface mixing, such as when placed below the mud line in offshore operations. The secondary initiator may be any suitable water-soluble compound or compounds that may react with the primary initiator to provide free radicals at a lower temperature. An example of a suitable secondary initiator is triethanolamine. In some embodiments of the present invention, the secondary initiator is present in the polymerizable organic monomer composition in an amount in the range of from about 0.1% to about 5% by weight of the water-soluble polymerizable organic monomer(s).

Also optionally, the polymerizable organic monomer compositions of the present invention further may comprise a crosslinking agent for crosslinking the polymerizable organic monomer compositions in the desired gelled substance. In some embodiments, the crosslinking agent is a molecule or complex containing a reactive transition metal cation. A most preferred crosslinking agent comprises trivalent chromium cations complexed or bonded to anions, atomic oxygen, or water. Examples of suitable crosslinking agents include, but are not limited to, compounds or complexes containing chromic acetate and/or chromic chloride. Other suitable transition metal cations include chromium VI within a redox system, aluminum III, iron II, iron III, and zirconium IV. Generally, the crosslinking agent may be present in polymerizable organic monomer compositions in an amount in the range of from 0.01% to about 5% by weight of the polymerizable organic monomer composition.

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. 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 (of the form, "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, and set forth every range encompassed within the broader range of values. Also, the terms in the claims have their plain, ordinary meaning unless otherwise explicitly and clearly defined by the patentee.

CLAIMS:

1. A method comprising:

introducing a cleanup fluid through a well bore and into a portion of a subterranean formation penetrated by the well bore;

applying a pressure pulse to the cleanup fluid, such that the pressure pulsed cleanup fluid moves a plurality of fines from a location in a fluid flow path in the portion of the subterranean formation, away from the well bore and into the subterranean formation; and

introducing a consolidating agent through the well bore and into the portion of the subterranean formation, wherein the consolidating agent has a viscosity in the range of about 1 cP to about 100 cP.

2. The method of claim 1 wherein the cleanup fluid dissolves scale, fines, or scales and fines in the portion of the subterranean formation.

3. The method of claim 1 wherein the portion of the subterranean formation comprises at least one member selected from the group consisting of a proppant pack, a gravel pack, a liner, a sand control screen, and a combination thereof.

4. The method of claim 1 wherein the pressure pulse dislodges a plurality of fines from fluid flow paths in the portion of the subterranean formation.

5. The method of claim 1 wherein the pressure pulse is applied at a frequency in the range of from about 0.001 Hz to about 1 Hz.

6. The method of claim 1 wherein the pressure pulse applied to the fluid generates a pressure pulse in the portion of the subterranean formation in the range of from about 10 psi to about 3,000 psi.

7. The method of claim 1 further comprising the step of:

flowing the cleanup fluid through a pulsonic device so as to generate the pressure pulse.

8. The method of claim 1 further comprising the step of:

flowing the cleanup fluid through a fluidic oscillator so as to generate the pressure pulse.

9. The method of claim 1 further comprising applying a pressure pulse to the consolidating agent.

10. The method of claim 1 wherein the consolidating agent comprises at least one consolidating agent selected from the group consisting of a non-aqueous tackifying agent, an aqueous tackifying agent, a resin, a gelable composition, and a combination thereof.

11. The method of claim 10 wherein the consolidating agent further comprises a solvent.

12. The method of claim 1 wherein the consolidating agent comprises a solvent and at least one non-aqueous tackifying agent selected from the group consisting of: a polyamide, a condensation reaction product of polyacids and a polyamine, a polyester; a polycarbonate, a polycarbamate, a natural resin, and a combination thereof.

13. The method of claim 1 wherein the consolidating agent comprises a solvent, a non-aqueous tackifying agent, and a multifunctional material.

14. The method of claim 1 wherein the consolidating agent comprises a solvent and an aqueous tackifying agent.

15. The method of claim 1 wherein the consolidating agent comprises a solvent and at least one aqueous tackifying agent selected from the group consisting of: an acrylic acid polymer, an acrylic acid ester polymer, an acrylic acid derivative polymer, an acrylic acid homopolymer, an acrylic acid ester homopolymer, an acrylic acid ester co-polymers, a methacrylic acid derivative polymers, a methacrylic acid homopolymers, a methacrylic acid ester homopolymers, an acrylamido-methyl-propane sulfonate polymer, an acrylamido-

methyl-propane sulfonate derivative polymer, an acrylamido-methyl-propane sulfonate co-polymer, an acrylic acid/acrylamido-methyl-propane sulfonate co-polymer, and a combination thereof.

16. The method of claim 1 wherein the consolidating agent comprises a solvent and an aqueous tackifying agent comprising a polyacrylate ester.

17. The method of claim 1 wherein the consolidating agent comprises a solvent, an aqueous tackifying agent, and an activator.

18. The method of claim 1 wherein the consolidating agent comprises a resin and a solvent.

19. The method of claim 1 wherein the consolidating agent comprises a solvent and at least one resin selected from the group consisting of: a two component epoxy based resin, a novolak resin, a polyepoxide resin, a phenol-aldehyde resin, a urea-aldehyde resin, a urethane resin, a phenolic resin, a furan resin, a furan/furfuryl alcohol resin, a phenolic/latex resin, a phenol formaldehyde resin, a polyester resin, a hybrid of a polyester resin, a copolymer of a polyester resin, a polyurethane resin, a hybrids of a polyurethane resin, a copolymer of a polyurethane resin, an acrylate resin, and a combination thereof.

20. The method of claim 1 wherein the consolidating agent comprises at least one gelable composition selected from the group consisting of: a gelable resin composition, a gelable aqueous silicate composition, a crosslinkable aqueous polymer composition, and a polymerizable organic monomer composition.

21. The method of claim 1 further comprising at least one step selected from the group consisting of:

shutting in the well bore for a period of time after the step of introducing the consolidating agent;

introducing an after-flush fluid into the portion of the subterranean formation after the step of introducing the consolidating agent;

fracturing the portion of the subterranean formation after the step of introducing the consolidating agent; and combinations of these steps.

22. A method of cleaning a sand control screen comprising:

introducing a cleanup fluid through a sand control screen and into a portion of a subterranean formation, the sand control screen located in a well bore that penetrates the subterranean formation;

applying a pressure pulse to the cleanup fluid, such that the pressure pulsed cleanup fluid moves a plurality of fines from a location in a fluid flow path in the portion of the subterranean formation, away from the well bore and into the subterranean formation; and

introducing a consolidating agent through the sand control screen and into the portion of the subterranean formation, wherein the consolidating agent has a viscosity in the range of about 1 cP to about 100 cP.

23. The method of claim 22 wherein the sand control screen is a wire-wrapped screen, a pre-packed screen, or an expandable screen.

24. The method of claim 22 wherein the cleanup fluid is introduced into the subterranean formation through a gravel pack located in an annulus between the sand control screen and the portion of the subterranean formation.

25. The method of claim 22 further comprising the step of:

flowing the cleanup fluid through a fluidic oscillator so as to generate the pressure pulse.

26. The method of claim 22 wherein the consolidating agent comprises at least one consolidating agent selected from the group consisting of a non-aqueous tackifying agent, an aqueous tackifying agent, a resin, a gelable composition, and a combination thereof.

27. A method of cleaning a sand control screen and gravel pack comprising:

placing a fluidic oscillator in a well bore in a location adjacent to a sand control screen located in the well bore;

introducing a cleanup fluid through the fluidic oscillator, through the sand control screen, through a gravel pack, and into a portion of a subterranean formation penetrated by the well bore, wherein the gravel pack is located in an annulus between the sand control screen and the portion of the subterranean formation and wherein a pressure pulse is generated in the cleanup fluid by introducing the cleanup fluid through the fluidic oscillator, such that the pressure pulsed cleanup fluid moves a plurality of fines from a location in a fluid flow path in the portion of the subterranean formation, away from the well bore and into the subterranean formation; and

introducing a consolidating agent through the sand control screen, through the gravel pack, and into the portion of the subterranean formation, wherein the consolidating agent has a viscosity in the range of about 1 cP to about 100 cP.

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FIG.2

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FIG.1

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FIG.4

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FIG.3

FIG.6

FIG.5

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