A method of treating a subterranean formation may include placing a first treatment fluid into a subterranean formation through an access conduit connecting the subterranean formation to a wellbore at a pressure sufficient to form at least a portion of a fracture network; pumping a second treatment fluid comprising a propping agent into the fracture network such that the propping agent forms a proppant pack in at least a portion of the fracture network; placing a third treatment fluid comprising a secondary diverting agent into the fracture network so as to substantially inhibit fluid flow through at least a portion of the fracture network without substantially inhibiting fluid flow through the access conduit; and placing a fourth treatment fluid comprising a primary diverting agent into the wellbore such that the primary diverting agent substantially inhibits fluid flow through the access conduit.
Figure 2

- fracture network
- wellbore
- access conduit
- fracture
- microfracture
- branch
- primary diverting agent
- secondary diverting agent
- degradable particle
FRACTURING PROCESS TO ENHANCE PROPPING AGENT DISTRIBUTION TO MAXIMIZE CONNECTIVITY BETWEEN THE FORMATION AND THE WELLOBRE

BACKGROUND

[0001] The present invention relates generally to enhancing propping agent distribution in order to maximize connectivity between a subterranean formation and a wellbore so as to improve production from a subterranean formation.

[0002] After a wellbore is drilled, it may often be necessary to fracture the subterranean formation to enhance hydrocarbon production, especially in shale formations that typically have high closure stresses. Access to the subterranean formation can be achieved by first creating an access conduit from the wellbore to the subterranean formation. Then, a fracturing fluid, called a pad, is introduced at pressures exceeding those required to maintain matrix flow in the formation permeability to create or enhance at least one fracture that propagates from at least one access conduit. The pad fluid is followed by a fluid comprising a propping agent to prop the fracture open after pressure is reduced. In some formations like shales, fractures can further branch into small fractures extending from a primary fracture giving depth and breadth to the fracture network created in the subterranean formation. As used herein, a “fracture network” refers to the access conduits, fractures, microfractures, and/or branches, man-made or otherwise, within a subterranean formation that are in fluid communication with the wellbore. The propping agents hold open the fracture network thereby maintaining the ability for fluid to flow through the fracture network to ultimately be produced at the surface.

[0003] Distribution of the propping agents is an important factor to maximizing production from the fracture network. Propping agents, like the fluid in which they are suspended, follow the path of least resistance, which in practice is typically into only a small percentage of fractures that have been created, and most definitely not into an appreciable number of branches that extend therefrom. Heterogeneous distribution of propping agents within a fracture network often yields a production curve with shorter steady state production and steep production decline, shown in FIG. 1a, i.e., the formation produces hydrocarbon for a shorter amount of time and production decline is very rapid. This is most often observed in shale and other very low permeability formations. Recovering a well after production decline typically involves refracturing, which can be costly and time consuming.

[0004] To provide a more uniform distribution of propping agents in the entire fracture network to maximize production potential, some form of diversion within or among zones in the subterranean formation may be useful. For example, a packer or bridge plug may be used between sets of access conduits to divert a treatment fluid between the access conduits. Also, sand may be used as diverting agents to plug or bridge an access conduit. In another technique, balls, commonly referred to as “perf balls,” may be used to seal off individual access conduits to divert fluid, and consequently propping agents, to other access conduits. Such techniques may be only partially successful towards uniform distribution of propping agents, especially in dendritic and shattered fracture networks, because they only address the distribution issues at the wellbore, i.e., at the access conduit, not within the highly interconnected, multi-branched fracture network.

[0005] One of many problems in the use of some or all of the above described procedures may be that the means of diverting the treatment fluid requires an additional step of removing it from the wellbore to allow the maximum flow of produced hydrocarbon from the subterranean zone into the wellbore. For example, a bridge plug generally is removed or drilled out at the end of the operation to allow for production. Similarly, sand plugs or bridges are cleaned out for production; sealing balls are often recovered for production, both of which incur additional time and expenses. Additionally, when the wellbore is to be treated is a highly deviated wellbore, traditional sand plugs are thought to be ineffective at isolating zones along the highly deviated wellbore because they may fail to fully plug the diameter of the wellbore. As used herein, the term “deviated wellbore” refers to a wellbore in which any portion of the well is in excess of about 55-degrees from a vertical inclination. As used herein, the term “highly deviated wellbore” refers to a wellbore that is oriented between 75-degrees and 90-degrees off-vertical (wherein 90-degrees off-vertical corresponds to a fully horizontal wellbore). That is, the term “highly deviated wellbore” may refer to a portion of a wellbore that is anywhere from fully horizontal (90-degrees off-vertical) to 75-degrees off-vertical.

SUMMARY OF THE INVENTION

[0006] The present invention relates generally to enhancing propping agent distribution in order to maximize connectivity between a subterranean formation and a wellbore so as to improve production from a subterranean formation.

[0007] In some embodiments, the present invention provides a method that comprises: providing a wellbore penetrating a subterranean formation, wherein the subterranean formation is able to support a fracture network; providing at least one access conduit to the subterranean formation from the wellbore; placing a first treatment fluid into the subterranean formation through the at least one access conduit at a pressure sufficient to form at least a portion of a fracture network extending from the at least one access conduit; pumping a second treatment fluid comprising a propping agent into the fracture network such that the propping agent forms a propant pack in at least a portion of the fracture network; placing a third treatment fluid comprising a secondary diverting agent into the wellbore such that the secondary diverting agent goes through the access conduit and into at least a portion of the fracture network so as to substantially inhibit fluid flow through at least a portion of the fracture network without substantially inhibiting fluid flow through the access conduit; and placing a fourth treatment fluid comprising a primary diverting agent into the wellbore such that the primary diverting agent substantially inhibits fluid flow through the access conduit.

[0008] In some embodiments, the present invention provides a method that comprises: providing a wellbore penetrating a subterranean formation, wherein the subterranean for-
A formation has a closure pressure greater than about 500 psi; providing at least one access conduit to the subterranean formation from the wellbore; placing a first treatment fluid into the subterranean formation through the at least one access conduit at a pressure sufficient to form at least a portion of a fracture network extending from the at least one access conduit; pumping a second treatment fluid comprising a propping agent into the fracture network such that the propping agent forms a proppant pack in at least a portion of the fracture network; placing a third treatment fluid comprising a secondary diverting agent into the wellbore such that the secondary diverting agent goes through the access conduit and into at least a portion of the fracture network so as to substantially inhibit fluid flow through at least a portion of the fracture network without substantially inhibiting fluid flow through the access conduit; and placing a fourth treatment fluid comprising a primary diverting agent into the wellbore such that the primary diverting agent substantially inhibits fluid flow through the access conduit.

In some embodiments, the present invention provides a method that comprises: providing a wellbore penetrating a subterranean formation, wherein the subterranean formation is able to support a fracture network and the wellbore has at least one access conduit to the subterranean formation from the wellbore; placing a first treatment fluid into the subterranean formation at a pressure sufficient to form at least a portion of a fracture network extending from at least one access conduit; pumping a second treatment fluid comprising a propping agent into the fracture network such that the propping agent forms a proppant pack in at least a portion of the fracture network, wherein the propping agent comprises proppant particulates at least partially coated with a consolidating agent and at least a portion of degradable particles; placing a third treatment fluid comprising a secondary diverting agent into the wellbore such that the secondary diverting agent goes through the access conduit and into at least a portion of the fracture network so as to substantially inhibit fluid flow through at least a portion of the fracture network without substantially inhibiting fluid flow through the access conduit, wherein the secondary diverting agent is at least partially degradable; placing a fourth treatment fluid comprising a primary diverting agent into the wellbore such that the primary diverting agent substantially inhibits fluid flow through the access conduit, wherein the primary diverting agent is at least partially degradable; and repeating at least one step selected from the group consisting of pumping the second treatment fluid, placing the third treatment fluid, placing the fourth treatment fluid, and any combination thereof.

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

BRIEF DESCRIPTION OF THE DRAWINGS

The following figures are included to illustrate certain aspects of the present invention, and should not be viewed as exclusive embodiments. The subject matter disclosed is capable of considerable modification, alteration, and equivalents in form and function, as will occur to those skilled in the art and having the benefit of this disclosure.

FIGS. 1a-b illustrate the production curve of a subterranean formation based on distribution of propping agents.

FIG. 2 illustrates the placement of elements within a dendritic fracture network.

FIG. 3 illustrates the placement of elements within a shattered fracture network.

FIG. 4 illustrates a nonlimiting example of a fracture network response to a method of the present invention.

FIG. 5 illustrates a nonlimiting example of wellbore pressure during a method of the present invention.

DETAILED DESCRIPTION

The present invention relates generally to enhancing propping agent distribution in order to maximize connectivity between a subterranean formation and a wellbore so as to improve production from a subterranean formation.

The methods of the present invention provide for the systematic introduction of a series of diverting agents that enhances the uniform distribution of propping agents throughout a fracture network. In brittle formations, such as shale, a fracture network may comprise access conduits, fractures, microfractures, and branches. As used herein, an “access conduit” refers to a passageway that provides fluid communication between the wellbore and the subterranean formation, which may include, but not be limited to, sliding sleeves, open holes in non-cased areas, hydrajetted holes, holes in the casing, perforations, and the like. The methods of the present invention provide for treatment fluid and propping agent diversion in at least each of these fracture network components. Uniform distribution of propping agents maximizes the connectivity between the formation and the wellbore, thereby maximizing hydrocarbon production therefrom. Further, the diversion methods provided herein better dilate the branches that give depth and breadth to a fracture network. Without being bound by theory, it is believed that dilated components of a fracture network more readily incorporate propping agents, which consequently yields more hydrocarbon in production operations. These methods may be particularly useful in deviated wellbores that are notorious for heterogeneous distribution of propping agents and heterogeneous fracture network dilation.

Uniform distribution of propping agents allows for the use of less overall propping agents, thereby reducing the cost of the operation. As depicted in the comparison of FIG. 1, uniform distribution of propping agents (FIG. 1b) may extend the lifetime of a well by increasing the length of the steady-state production and reducing the rate of production decline, as compared to heterogeneous propping agent distribution (FIG. 1a).

Further advantageously, some embodiments may include some combination of the various diverting agents being degradable. Degradable diverting agents decrease, and may eliminate, the need for secondary operations to restore fluid conductivity within the fracture network when production operations begin, which consequently reduces the environmental impact of subterranean operations. This reduces the cost and time for fracturing operations.

In some methods of the present invention, any combination of propping agents, a primary diverting agent, a secondary diverting agent, and optionally a degradable particle may be introduced via a treatment fluid into a wellbore penetrating a subterranean formation. In some embodiments, the elements of a propping agent, a primary diverting agent, a secondary diverting agent, and optionally a degradable particle may be introduced into a wellbore via a single treatment fluid comprising all of the elements, individual treatment
fluids comprising a single element, a plurality of treatment fluids comprising some combination of at least two of the elements, and any combination thereof. As used herein, the term “treatment,” or “treating,” refers to any subterranean operation that uses a fluid in conjunction with a desired function and/or for a desired purpose. The term “treatment,” or “treating,” does not imply any particular action by the fluid.

[0024] As used herein, a “diverting agent” refers to any material that can be used to substantially seal off a portion of a subterranean formation thereby substantially reducing, including blocking, fluid flow therethrough. As used herein, a “primary diverting agent” refers to a diverting agent that substantially inhibits fluid flow through an access conduit. As used herein, a “secondary diverting agent” refers to a diverting agent that substantially inhibits fluid flow through at least a portion of the fracture network. Suitable diverting agents may comprise gels, particles, and/or fibers that are natural or synthetic; degradable or nondegradable; and mixtures thereof. Nonlimiting examples of suitable diverting agents are included below.

[0025] As used herein, “propping agents” refers to any material or formulation that can be used to hold open at least a portion of a fracture network. As used herein, a “proppant pack” is the collection of propping agents in a fracture network.

[0026] As used herein, a “degradable particle,” and derivatives thereof, refers to any material that can be used in conjunction with a proppant pack that when substantially degraded leaves a void in the proppant pack. It should be understood that the term “particulate” or “particle,” and derivatives thereof as used in this disclosure, includes all known shapes of materials, including substantially spherical materials, low to high aspect ratio materials, fibrous materials, polygonal materials (such as cubic materials), and mixtures thereof. As used herein, the terms “degradation” or “degradable” refer to both the relatively extreme cases of hydrolytic degradation that the degradable material may undergo, e.g., heterogeneous (or bulk erosion) and homogeneous (or surface erosion), and any stage of degradation in between these two. This degradation can be a result of, inter alia, a chemical or thermal reaction, or a reaction induced by radiation. Nonlimiting examples of degradable particles are included below.

[0027] It should be noted that when “about” is provided at the beginning of a numerical list, “about” modifies each number of the numerical list. It should be noted that in some numerical listings of ranges, some lower limits listed may be greater than some upper limits listed. One skilled in the art will recognize that the selected subset will require the selection of an upper limit in excess of the selected lower limit.

[0028] In some embodiments, at least one access conduit from the wellbore to the subterranean formation may be created. In some embodiments, at least one access conduit from the wellbore to the subterranean formation may be provided. These access conduits may be made by any means or techniques known in the art including, but not limited to, hydraulic fracturing; laser inscribing; perforating; not casing at least a portion of the wellbore, and the like. Suitable examples of perforation tools and methods may include, but not be limited to, those disclosed in U.S. Pat. Nos. 5,398,760; 5,701,957; 6,435,278; 7,159,660; 7,172,023; 7,225,809; 7,303,017, and 7,841,396, the entirety of which are incorporated herein by reference. Access conduits may be spaced randomly, spaced substantially equidistant from each other, clustered in groups (e.g., an access conduit cluster), or any combination thereof along the length of the wellbore.

[0029] In some embodiments, a treatment fluid may be introduced into a wellbore at a pressure sufficient to form at least one fracture extending from at least one access conduit into a subterranean formation. In some embodiments, the pressure may be sufficient to form at least one branch extending from at least one fracture. In some embodiments, the pressure may be sufficient to form a fracture network. In some embodiments, the pressure may be sufficient to form at least a portion of a fracture network. In some embodiments, a fracture network may comprise access conduits, fractures, microfractures, branches, or any combination thereof including those which are natural and man-made. In some embodiments, a fracture network may be considered a dendritic fracture network, a shattered fracture network, or any combination thereof. FIG. 2 illustrates a nonlimiting example of a dendritic fracture network extending from a wellbore into a subterranean formation. FIG. 3 illustrates a nonlimiting example of a shattered fracture network extending from a wellbore into a subterranean formation. These nonlimiting examples illustrate two types of fracture networks extending from a horizontal well. It should be understood that the methods provided herein are applicable to wells at any angle including, but not limited to, vertical wells, deviated wells, highly deviated wells, horizontal wells, and hybrid wells comprising sections of any combination of the aforementioned wells. In some embodiments, a subterranean formation and wellbore may be provided with an existing fracture network.

[0030] In some methods of the present invention, any single or combination of elements including propping agents, a primary diverting agent, a secondary diverting agent, and a degradable particle may be placed via a treatment fluid into a wellbore penetrating a subterranean formation. It should be noted that placing may include pumping, introducing, adding, injecting, inserting, and the like.

[0031] Some embodiments of the present invention may include the following steps:

[0032] (a) placing a first treatment fluid into a wellbore at a pressure sufficient to create or enhance at least a portion of a fracture network;

[0033] (b) placing a second treatment fluid comprising propping agents into a wellbore;

[0034] (c) placing a third treatment fluid comprising a secondary diverting agent into the wellbore;

[0035] (d) placing a fourth treatment fluid comprising a primary diverting agent into the wellbore; and

[0036] (e) optionally placing a fifth treatment fluid comprising a degradable particulate into the wellbore.

[0037] It should be noted that the number modifiers, i.e., first, second, third, fourth, and fifth, do not necessarily indicate an order of placement or differences in composition. They are only meant to differentiate between treatment fluids. In some embodiments, a method of treating a subterranean formation may comprise either step c or step d listed above.

[0038] As described above and illustrated in FIG. 2, a primary diverting agent may substantially inhibit fluid flow through an access conduit and/or divert fluid flow to another access conduit. A secondary diverting agent may substantially inhibit fluid flow within the fracture network, e.g., through a fracture and/or a branch so as to divert fluid flow to branches extending from the fracture. A degradable particle
may incorporate into a proppant pack such that when substantially degraded a void in the proppant pack is produced. [0039] In some embodiments, the steps provided above may be performed in order. In some embodiments, one or more steps may be performed more than once. In some embodiments, one or more steps may be performed simultaneously. In some embodiments, the steps provided above may be performed in any order. Nonlimiting examples of methods of the present invention may include the following:

[0040] (1) a/h-b/c-b/c-e-c/a-b/b/c/c/c-e/c/e/c/e;
[0041] (2) a/b-c/e-b/c-b/c-e/c-e/c/e-e/c/c/b; and
[0042] (3) a/b/e-b/c-e/c-b/c-b/c-e/b/c-b/c/e/b/c.

It should be noted that performing two steps simultaneously, i.e., b/c, indicates that the second treatment fluid and the third treatment fluid are one in the same. Other combinations may also be suitable.

[0043] The diversion methods of the present invention may provide for better dilution of the components of the fracture network, which enhances hydrocarbon production. By way of nonlimiting example, FIG. 4 illustrates the dilution (line thickening) of a fracture network as the steps of b/e-b/c/c-c-b/c-b/c-c/b/c are performed on an already fractured subterranean formation (propping agents not shown, only dilution progression).

[0044] In some embodiments, the amount of an element within a treatment fluid may vary during a step. By way of nonlimiting example, the introduction of propping agents in a treatment fluid may be at 30 pounds per gallon (“ppg”) when the step begins then reduce to 10 ppg when the end of the step is complete. In some embodiments, changing the amount of an element in a treatment fluid may be an increase or decrease as a stepwise change, a gradient change, or any combination thereof. In some embodiments where multiple elements are introduced simultaneously, the amount of one or more elements may change during the step.

[0045] In some embodiments, the amount of element(s) may stay constant while the amount of other additive(s), including those described below, are changed. In some embodiments, both the amount of element(s) and additive(s) may change within a step.

[0046] In some embodiments, the methods of the present invention optionally may comprise monitoring the flow of one or more treatment fluids in at least a portion of the subterranean formation during all or part of a method of the present invention. Monitoring may, for example, ensure a primary and/or secondary diverting material are being placed appropriately within the fracture network, determine the presence or absence of a primary and/or secondary diverting material in the fracture network, and/or determine whether a primary and/or secondary diverting material actually diverts fluids introduced into the subterranean formation. Monitoring may be accomplished by any technique or combination of techniques known in the art. In certain embodiments, this may be accomplished by monitoring the fluid pressure at the surface of a wellbore penetrating the subterranean formation where fluids are introduced. For example, if the fluid pressure at the surface increases, this may indicate that the fluid is being diverted within the fracture network. Additionally, a pressure decrease or substantially steady-state pressure may indicate a portion of the fracture network is diluting. Pressure monitoring techniques may include various logging techniques and/or computerized fluid tracking techniques known in the art that are capable of monitoring fluid flow. Examples of commercially available services involving surface fluid pressure sensing that may be suitable for use in the methods of the present invention include those available under the trade-names EZ-GAUGE™ (surface pressure sensing tools, available from Halliburton Energy Services, Inc., Duncan, Okla.),

[0047] It should be noted that fluid pressure changes may not always be observable at the wellbore surface during fluid diversion and/or fracture network dilation. By way of nonlimiting example, fluid diversion because of placement of a secondary diverting agent may occur without an observable by an increase in fluid pressure at the wellbore surface.

[0048] In some embodiments, an element may be introduced into the wellbore after the wellbore pressure increases and begins to level off. In some embodiments, an element may be introduced into the wellbore during substantially steady-state wellbore pressure. By way of nonlimiting example, FIG. 5 illustrates two possible operations using methods of the present invention. In Scenario 1, propping agents are introduced in a periodic fashion; while in Scenario 2, the propping agents are introduced continuously and increased step-wise over time. At steady-state wellbore pressure, secondary diverting agent is added in twice followed by introduction of the primary diverting agent. The primary diverting agent substantially blocks the flow of fluid through an access conduit causing wellbore pressure to increase. These steps are repeated with similar results.

[0049] In some embodiments, monitoring the flow of one or more treatment fluids in at least a portion of the subterranean formation may be accomplished, in part, by using a distributed temperature sensing (DTS) technique. These techniques may involve a series of steps. Generally, a temperature sensing device (e.g., thermocouples, thermistors, or fiber optic cables) may be placed in a wellbore penetrating a portion of a subterranean formation, either permanently or retrievably, to record temperature data in the formation and/or the wellbore. In certain applications, a fiber optic cable may be pre-installed in a casing string before the casing string is placed in the wellbore. In some applications, it may be desirable to use an additional apparatus (e.g., coiled tubing) or fluid to place the fiber optic cable in the wellbore. In some embodiments, one may establish baseline temperature profile for all or part of the subterranean formation, and then monitor changes in temperature to determine the flow of fluids in various portions of the subterranean formation. Various computer software packages may be used to process the temperature data and/or create visualizations based on that data. Certain DTS techniques that may be suitable for use in the methods of the present invention may include commercially-available DTS services such as those known under the trade-names STIMWATCH® (available from Halliburton Energy Services, Inc., Duncan, Okla.) or SENSATM (available from Schlumberger Technology Corporation, Sugar Land, Tex.). Certain examples of DTS techniques that may be suitable for use in the methods of the present invention also may include those described in U.S. Pat. Nos. 5,028,146; 6,557,630; 6,751,556; 7,055,604; and 7,086,484, the entire disclosures of which are incorporated herein by reference. One of ordinary skill in the art, with the benefit of this disclosure, should recognize whether it is desirable to monitor the flow of one or more treatment fluids in at least a portion of the subterranean formation as well as techniques of doing so appropriate for a particular application of the present invention based on, inter alia, the characteristics of various portions of the subterranean formation, the types of treatment fluids present, equipment availability, and other relevant factors.
The methods of the present invention may be used in any subterranean formation capable of being fractured. Formations where the present methods may be most advantageous include, but are not limited to, formations with at least a portion of the formation characterized by very low permeability; very low formation pore throat size; high closure pressures; high brittleness index; and any combination thereof.

In some embodiments, at least a portion of a subterranean formation may have a permeability ranging from a lower limit of about 0.1 nano Darcy (nD); 1 nD, 10 nD, 25 nD, 50 nD, 100 nD, or 500 nD to an upper limit of about 10 mD, 1 mD, 500 microD, 100 microD, 10 microD, or 500 nD, and wherein the permeability may range from any lower limit to any upper limit and encompass any subset thereof. One method to determine the subterranean formation permeability includes The American Petroleum Institute Recommended Practice 40, “Recommended Practices for Core Analysis.” Second Edition, February 1998, the entirety of which is incorporated herein by reference.

In some embodiments, at least a portion of a subterranean formation may have an average formation pore throat size ranging from a lower limit of about 0.005 microns, 0.01 microns, 0.05 microns, 0.1 microns, 0.25 microns, or 0.5 microns to an upper limit of about 2.0 microns, 1.5 microns, 1.0 microns, or 0.5 microns, and wherein the average formation pore throat size may range from any lower limit to any upper limit and encompass any subset thereof. One method to determine the pore throat size of a subterranean formation includes the AAPG Bulletin, March 2009, v. 93, no. 3, pages 329-340, the entirety of which is incorporated herein by reference.

In some embodiments, at least a portion of a subterranean formation may have a closure pressure greater than about 500 psi to an unlimited upper limit. While the closure pressure upper limit is believed to be unlimited, formations where the methods of the present invention may be applicable include formations with a closure pressure ranging from a lower limit of about 500 psi, 1000 psi, 1500 psi, or 2500 psi to an upper limit of about 20,000 psi, 15,000 psi, 10,000 psi, 8500 psi, or 5000 psi, and wherein the closure pressure may range from any lower limit to any upper limit and encompass any subset thereof. One method to determine the subterranean formation closure pressure includes the method presented in the Society for Petroleum Engineers paper number 60321, the entirety of which is incorporated herein by reference.

In some embodiments, at least a portion of a subterranean formation may have a brittleness index ranging from a lower limit of about 5, 10, 20, 30, 40, or 50 to an upper limit of about 150, 125, 100, or 75, and wherein the brittleness index may range from any lower limit to any upper limit and encompass any subset thereof. Britteness is a composite of Poisson’s ratio and Young’s modulus. One method to determine the brittleness index of a subterranean formation includes the method presented in the Society for Petroleum Engineers paper number 132990, the entirety of which is incorporated herein by reference.

In certain embodiments, all or part of a wellbore penetrating the subterranean formation may include casing pipes or strings placed in the wellbore (a “cased hole” or a “partially cased hole”), among other purposes, to facilitate production of fluids out of the formation and through the wellbore to the surface. In other embodiments, the wellbore may be an “open hole” that has no casing.

In some embodiments, the methods disclosed herein may be used in conjunction with zipper fracture techniques. Zipper fracture techniques use pressurized fracture networks in at least one wellbore to direct the fracture network of a second, nearby wellbore. Because the first fracture network is pressurized and exerting a stress on the subterranean formation, the second pressure network may extend through the path of least resistance, i.e., the portions of the subterranean formation under less stress. Continuing to hold open portions of the fracture network with propping agent may continue to provide stress on the subterranean formation even with a reduced fluid pressure therein. Therefore, enhancing the uniform distribution of propping agents through a fracture network may enhance efficacy of a zipper fracture technique. In some embodiments, any of the diversion methods described herein may be implemented in at least one wellbore to enhance the fracture network of at least one nearby wellbore.

Suitable diverting agents (primary or secondary) for use in the present invention may be any known diverting agent including, but not limited to, any known lost circulation material, bridging agent, fluid loss control agent, diverting agent, plugging agent, or the like suitable for use in a subterranean formation. Suitable diverting agents may comprise gels, particles, and/or fibers that are natural or synthetic, degradable or nondegradable, and mixtures thereof. Limiting examples of commercially available diverting agents include diverting agents in the BIOVERT®, series (degradable diverting agents) available from Halliburton Energy Services, Inc. including, but not limited to BIOVERT® NWB (a biomodal, degradable diverting agent, available from Halliburton Energy Services, Inc.) as a primary diverting agent and BIOVERT® RFC (a degradable diverting agent, available from Halliburton Energy Services, Inc.) as a secondary diverting agent.

Primary diverting agents for use in the present invention may comprise particulates. In some embodiments, particulates of a primary diverting agent may have an average diameter ranging from a lower limit of about 0.5 microns, 1 micron, 10 microns, 100 microns, or 500 microns to an upper limit of about 0.5 mm, 5 mm, 1 mm, 500 microns, or 10 microns, and wherein the average diameter may range from any lower limit to any upper limit and encompass any subset thereof. In some embodiments, particulates of a primary diverting agent may have a multi-modal diameter distribution including bimodal.

Secondary diverting agents for use in the present invention may comprise particulates. In some embodiments, particulates of a secondary diverting agent may have an average diameter less than about 150 microns. Suitable average diameters for particulates of a secondary diverting agent may range from a lower limit of about 100 nm, 250 nm, 500 nm, 1 micron, 10 microns, 50 microns to an upper limit of about 150 microns, 100 microns, 50 microns, or 10 microns, and wherein the average diameter may range from any lower limit to any upper limit and encompass any subset thereof. In some embodiments, the secondary diverting agent may have an average diameter less than or equal to a proppant particulate of the propping agents. In some embodiments, the primary diverting agent may comprise particulates with a larger average diameter than particulates of a secondary diverting agent.

Suitable examples of materials for a diverting agent include, but are not limited to, sand, shale, ground marble,
bauxite, ceramic materials, glass materials, metal pellets, high strength synthetic fibers, cellulose flakes, wood, resins, polymer materials (crosslinked or otherwise), polytetrafluoroethylene materials, nut shell pieces, cured resinous particulates comprising nut shell pieces, seed shell pieces, cured resinous particulates comprising seed shell pieces, fruit pit pieces, cured resinous particulates comprising fruit pit pieces, composite particulates, and any combination thereof. Suitable composite particulates may comprise a binder and a filler material wherein suitable filler materials include silica, alumina, fumed carbon, carbon black, graphite, mica, titanium dioxide, meta-silicate, calcium silicate, kaolin, talc, zirconia, boron, fly ash, hollow glass microspheres, solid glass, and any combination thereof.

[0061] In some embodiments, a diverting agent may be at least partially degradable. Nonlimiting examples of suitable degradable materials that may be used in the present invention include, but are not limited to, degradable polymers (crosslinked or otherwise), dehydrated compounds, and/or mixtures of the two. Examples of suitable degradable solid particulates may be found in U.S. Pat. Nos. 7,036,587; 6,896,058; 6,323,307; 5,216,050; 4,387,769; 3,912,692; and 2,703,316, the relevant disclosures of which are incorporated herein by reference. The terms “polymer” or “polymers” as used herein do not imply any particular degree of polymerization; for instance, oligomers are encompassed within this definition. A polymer is considered to be “degradable” herein if it is capable of undergoing an irreversible degradation when used in subterranean applications, e.g., in a wellbore. The term “irreversible” as used herein means that the degradable material should degrade in situ (e.g., within a wellbore) but should not recrystallize or reconsolidate in situ after degradation (e.g., in a wellbore).

[0062] Degradable materials may include, but not be limited to, dissolvable materials, materials that deform or melt upon heating such as thermoplastic materials, hydrolytically degradable materials, materials degradable by exposure to radiation, materials reactive to acidic fluids, or any combination thereof. In some embodiments, degradable materials may be degradable by temperature, presence of moisture, oxygen, microorganisms, enzymes, pH, free radicals, and the like. In some embodiments, degradation may be initiated in a subsequent treatment fluid introduced into the subterranean formation at some time when diverting is no longer necessary. In some embodiments, degradation may be initiated by a delayed-release acid, such as an acid-releasing degradable material or an encapsulated acid, and this may be included in the treatment fluid comprising the degradable material so as to reduce the pH of the treatment fluid at a desired time, for example, after introduction of the treatment fluid into the subterranean formation.

[0063] In choosing the appropriate degradable material, one should consider the degradation products that will result. Also, these degradation products should not adversely affect other operations or components. For example, a boric acid derivative may not be included as a degradable material in the well drill-in and servicing fluids of the present invention where such fluids use guar as the viscosifier, because boric acid and guar are generally incompatible. One of ordinary skill in the art, with the benefit of this disclosure, will be able to recognize when potential components of a treatment fluid of the present invention would be incompatible or would produce degradation products that would adversely affect other operations or components.

[0064] The degradability of a degradable polymer often depends, at least in part, on its backbone structure. For instance, the presence of hydrolyzable and/or oxidizable linkages in the backbone often yields a material that will degrade as described herein. The rates at which such polymers degrade are dependent on the type of repetitive unit, composition, sequence, length, molecular geometry, molecular weight, morphology (e.g., crystallinity, size of spherulites, and orientation), hydrophilicity, hydrophobicity, surface area, and additives. Also, the environment to which the polymer is subjected may affect how it degrades, e.g., temperature, presence of moisture, oxygen, microorganisms, enzymes, pH, and the like.

[0065] Suitable examples of degradable polymers for a solid particulate of the present invention that may be used include, but are not limited to, polysaccharides such as cellulose; chitin; chitosan; and proteins. Suitable examples of degradable polymers that may be used in accordance with the present invention include, but are not limited to, those described in the publication of Advances in Polymer Science, Vol. 157 entitled “Degradable Aliphatic Polyesters,” edited by A. C. Albertsson, pages 1-138. Specific examples include homopolymers, random, block, graft, and star- and hyper-branched aliphatic polyesters. Such suitable polymers may be prepared by polycondensation reactions, ring-opening polymerizations, free radical polymerizations, anionic polymerizations, carboxylic polymerizations, and ring-opening polymerizations, as well as by any other suitable process. Examples of suitable degradable polymers that may be used in conjunction with the methods of this invention include, but are not limited to, aliphatic polyesters; poly(lactides); poly(glycolides); poly(ε-caprolactones); poly(hydroxy ester ethers); poly(hydroxybutyrates); poly(β-hydroxides); polycarbonates; poly(orthoesters); poly(amino acids); poly(ethylene oxides); poly(phosphazenes); poly(ether esters), polyester amides, polyamides, and copolymers or blends of any of these degradable polymers, and derivatives of these degradable polymers. The term “copolymer” as used herein is not limited to the combination of two polymers, but includes any combination of polymers, e.g., terpolymers and the like. As referred to herein, the term “derivative” is defined herein to include any compound that is made from one of the listed compounds, for example, by replacing one atom in the base compound with another atom or group of atoms. Of these suitable polymers, aliphatic polyesters such as poly(lactic acid), poly(β-hydroxides), poly(orthoesters), and poly(lactic-co-glycolide) copolymers are preferred. Poly(lactic acid) is especially preferred. Poly(orthoesters) may also be preferred. Other degradable polymers that are subject to hydrolytic degradation also may be suitable. One’s choice may depend on the particular application and the conditions involved. Other guidelines to consider include the degradation products that result, the time required for the requisite degree of degradation, and the desired result of the degradation (e.g., voids).

[0066] Aliphatic polyesters degrade chemically, inter alia, by hydrolytic cleavage. Hydrolysis can be catalyzed by either acids or bases. Generally, during the hydrolysis, carboxylic end groups may be formed during chain scission, which may enhance the rate of further hydrolysis. This mechanism is known in the art as “autocatalysis,” and is thought to make polyester matrices more bulk-eroding.
Suitable aliphatic polyesters have the general formula of repeating units shown below:

\[
\begin{align*}
\text{Formula I} \\
\text{where } n \text{ is an integer between 75 and 10,000 and } R \text{ is selected from the group consisting of hydrogen, alkyl, aryl, alkylaryl, acetyl, heteroatoms, and mixtures thereof. In certain embodiments, the aliphatic polyester is used, the aliphatic polyester may be poly(lactic acid). Poly(lactide) is synthesized either from lactic acid by a condensation reaction or, more commonly, by ring-opening polymerization of cyclic lactide monomer. Since both lactic acid and lactide can achieve the same repeating unit, the general polymer poly(lactic acid) as used herein refers to at least one repeating unit.}
\end{align*}
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where \( m \) is an integer in the range of from greater than or equal to 2 to less than or equal to about 75. In certain embodiments, \( m \) may be an integer in the range of from greater than or equal to 2 to less than or equal to about 10. These limits may correspond to number average molecular weights below about 5,400 and below about 720, respectively. The chirality of the lactide units provides a means to adjust, inter alia, degradation rates, as well as physical and mechanical properties. Poly(L-lactide), for instance, is a semicrystalline polymer with a relatively slow hydrolysis rate. This could be desirable in applications of the present invention in which a shorter degradation of the degradable material is desired. Poly(D,L-lactide) may be a more amorphous polymer with a resultant faster hydrolysis rate. This may be suitable for other applications in which a more rapid degradation may be appropriate. The stereoisomers of lactic acid may be used individually, or may be combined in accordance with the present invention. Additionally, they may be copolymerized with, for example, glycolide or other monomers like \( \varepsilon \)-caprolactone, 1,5-dioxepan-2-one, trimethylene carbonate, or other suitable monomers to obtain polymers with different properties or degradation times. Additionally, the lactic acid stereoisomers can be modified by blending high and low molecular weight polylactide or by blending poly(lactide) with other polyesters. In embodiments wherein polylactide is used as the degradable material, certain preferred embodiments employ a mixture of the D and L stereoisomers, designed so as to provide a desired degradation time and/or rate. Examples of suitable sources of degradable material are commercially available 6250DM (poly(lactic acid), available from Cargill Dow) and 5639AM (poly(lactic acid), available from Cargill Dow).

Polyanhydrides are another type of degradable polymer that may be suitable for use in the present invention. Poly(anhydride) hydrolysis proceeds, inter alia, via free carboxylic acid chain-ends to yield carboxylic acids as final degradation products. Their erosion time can be varied over a broad range of changes in the polymer backbone. Examples of suitable polyanhydrides include poly(adipic anhydride), poly(sebacic anhydride), poly(sebacic anhydride), and poly(dodecanedioic anhydride). Other suitable examples include, but are not limited to, poly(maleic anhydride) and poly(benzoic anhydride).

The physical properties of degradable polymers may depend on several factors including, but not limited to, the composition of the repeat units, flexibility of the chain, presence of polar groups, molecular mass, degree of branching, crystallinity, and orientation. For example, short chain branches may reduce the degree of crystallinity of polymers while long chain branches may lower the melt viscosity and may impart, inter alia, extensional viscosity with tension-stiffening behavior. The properties of the material utilized further may be tailored by blending, and copolymerizing it with another polymer, or by a change in the macromolecular architecture (e.g., hyper-branched polymers, star-shaped, or dendrimers, and the like). The properties of any such suitable degradable polymers (e.g., hydrophobicity, hydrophilicity, rate of degradation, and the like) can be tailored by introducing select functional groups along the polymer chains. For example, poly(phenylactide) will degrade at about one-fifth of the rate of racemic poly(lactide) at a pH of 7.4 at 55°C. One of ordinary skill in the art, with the benefit of this disclosure, will be able to determine the appropriate functional groups to introduce to the polymer chains to achieve the desired physical properties of the degradable polymers.

Suitable dehydrated compounds for use as solid particulates in the present invention may degrade over time as they are rehydrated. For example, a particulate solid anhydrous borate material that degrades over time may be suitable for use in the present invention. Specific examples of particulate solid anhydrous borate materials that may be used include, but are not limited to, anhydrous sodium tetraborate (also known as anhydrous borax) and anhydrous boric acid.

Whichever degradable material is used in the present invention, the degradable material may have any shape, including, but not limited to, particles having the physical shape of platelets, shavings, flakes, ribbons, rods, strips, spheres, toroids, pellets, tablets, or any other physical shape. In certain embodiments of the present invention, the degradable material used may comprise a mixture of fibers and spherical particles. One of ordinary skill in the art, with the benefit of this disclosure, will recognize the specific
degradable material that may be used in accordance with the present invention, and the preferred size and shape for a given application.

In choosing the appropriate degradable material, one should consider the degradation products that will result, and choose a degradable material that will not yield degradation products that would adversely affect other operations or components utilized in that particular application. The choice of degradable material also may depend, at least in part, on the conditions of the well (e.g., wellbore temperature). For instance, lactides have been found to be suitable for lower temperature wells, including those within the range of 60°F to 150°F, and polylactides have been found to be suitable for wellbore temperatures above this range.

In certain embodiments, the degradation of the degradable material could result in a final degradation product having the potential to affect the pH of the self-degrading cement compositions utilized in the methods of the present invention. For example, in certain embodiments wherein the degradable material is polylactic acid, the degradation of the polylactic acid to produce lactic acid may alter the pH of the self-degrading cement composition. In certain embodiments, a buffer compound may be included within the self-degrading cement compositions utilized in the methods of the present invention in an amount sufficient to neutralize the final degradation product. Examples of suitable buffer compounds include, but are not limited to, calcium carbonate, magnesium oxide, ammonium acetate, and the like. One of ordinary skill in the art, with the benefit of this disclosure, will be able to identify the proper type and concentration of a buffer compound to include in the self-degrading cement composition for a particular application. An example of a suitable buffer compound comprises commercially available BA20™ (ammonium acetate, available from Halliburton Energy Services, Inc.).

In some embodiments, a diverting agent may be a gel. In some embodiments, the gel may be a crosslinked gel. Examples of gel diverting agents may include, but are not limited to, fluids with high concentration of gels such as xanthan. Examples of crosslinked gels that can be used as the diverting agent include, but are not limited to, high concentration gels such as DELTA FRAC™ fluids (high viscosity borate gel, available from Halliburton Energy Services, Inc.), K-MAX™ fluids (crosslinkable hydroxyethyl cellulose, available from Halliburton Energy Services, Inc.), and K-MAX-PLUS™ fluids (crosslinkable hydroxyethyl cellulose, available from Halliburton Energy Services, Inc.). Gels may also be used by mixing the crosslinked gels with delayed chemical breakers, encapsulated chemical breakers, which will later reduce the viscosity, or with a material such as PLA (poly-lactic acid) beads, which although being a solid material, with time decomposes into acid, which will liquefy the K-MAX™ fluids or other crosslinked gels.

The gel diverting agents suitable for use in the present invention may comprise any substance (e.g., a polymeric material) capable of increasing the viscosity of the treatment fluid. In certain embodiments, the diverting agent may comprise one or more polymers that have at least two molecules that are capable of forming a crosslink in a crosslinking reaction in the presence of a crosslinking agent, and/or polymers that have at least two molecules that are so crosslinked (i.e., a crosslinked gelling agent). The gel diverting agents may be naturally-occurring gel diverting agents, synthetic gel diverting agents, or a combination thereof. The gel diverting agents also may be cationic, anionic, amphoteric, or a combination thereof. Suitable gel diverting agents include, but are not limited to, polysaccharides, biopolymers, and/or derivatives thereof that contain one or more of these monosaccharide units: galactose, mannose, glucosamine, glucose, xylose, arabinose, fructose, glucuronic acid, or pyranosyl sulfate. Examples of suitable polysaccharides include, but are not limited to, guar gums (e.g., hydroxyethyl guar, hydroxypropyl guar, carboxymethyl guar, carboxymethylhydroxyethyl guar, and carboxymethylhydroxypropyl guar (“CMHPG”)), cellulose derivatives (e.g., hydroxyethyl cellulose, carboxymethylcellulose, carboxymethylcellulose, and carboxymethylhydroxyethylcellulose), xanthan, scleroglucan, diutan, and combinations thereof. In certain embodiments, the gelling agents comprise an organic carboxylated polymer, such as CMHPG.

Suitable synthetic polymers for use as gel diverting agents include, but are not limited to, 2,2’-azobis(2,4-dimethyl valeronitrile), 2,2’-azobis(2,4-dimethyl-4-methoxyvaleronitrile), polymers and copolymers of acrylamide ethyltrithiomethyl ammonium chloride, acrylamide, acrylamido- and methacrylamido-alkyl trialkyl ammonium salts, acrylamidomethylpropane sulfonic acid, acrylamidopropyl trimethyl ammonium chloride, acrylic acid, dimethylaminoethyl methacrylamide, dimethylaminoethyl methacrylate, dimethylaminopropyl methacrylamide, dimethylaminopropylmethacrylamide, dimethylacrylamide, dimethylacrylamidopropyl trimethyl ammonium chloride, methacrylamidopropyl(dimethylamino)-n-dodecylammonium chloride, methacrylamidopropyl(dimethylamino)-ethylammonium chloride, methacryloyloxyalkyl trialkyl ammonium salts, methacrylicacyloyloxyalkyl trimethyl ammonium chloride, methacrylamidopropyl(dimethylamino)-ethylammonium chloride, N-(3-sulfopropyl)-N,N-dimethylamidopropyl-N,N-dimethyl ammonium betaine, N,N-dimethylacrylamide, N-methylacrylamide, nonylphenoxy(poly(ethyleneoxy)ethylenemethacrylate, partially hydrolyzed polyacrylamide, poly 2-amino-2-methyl propane sulfonic acid, polyvinyl alcohol, sodium 2-acrylamido-2-methylpropane sulfonate, quaternized dimethylaminocarboxylate, quaternized dimethylaminosulfonate, methacrylamide, and derivatives and combinations thereof. In certain embodiments, the gelling agent comprises an acrylamide/2-(methacryloyloxyethyltrimethylammonium methyl sulfate copolymer. In certain embodiments, the gelling agent may comprise an acrylamide/2-(methacryloyloxy) ethyltrithiomethylammonium chloride copolymer. In certain embodiments, the gelling agent may comprise a derivatized cellulose that comprises cellulose grafted with an allyl or a vinyl monomer, such as those disclosed in U.S. Pat. Nos. 4,982,793; 5,067,565; and 5,122,549, the entire disclosures of which are incorporated herein by reference.

Additionally, polymers and copolymers that comprise one or more functional groups (e.g., hydroxyl, cis-hydroxyl, carboxylic acids, derivatives of carboxylic acids, sulfonate, sulfonate, phosphate, phosphonate, amino, or amide groups) may be used as gel diverting agents.

In those embodiments of the present invention where it is desirable to crosslink the gel diverting agents in situ, the treatment fluid comprising the gel diverting agents and/or a subsequent treatment fluid may comprise one or more crosslinking agents. The crosslinking agents may comprise a borate ion, a metal ion, or similar component that is
capable of crosslinking at least two molecules of the gelling agent. Examples of suitable crosslinking agents include, but are not limited to, borate ions, magnesium ions, zirconium IV ions, titanium IV ions, aluminum ions, antimony ions, chromium ions, iron ions, copper ions, magnesium ions, and zinc ions. These ions may be provided by providing any compound that is capable of producing one or more of these ions. Examples of such compounds include, but are not limited to, ferric chloride, boric acid, disodium octaborate tetrahydrate, sodium diborate, pentaborates, ulexite, colemanite, magnesium oxide, zirconium lactate, zirconium triethanol amine, zirconium lactate triethanolamine, zirconium carbonate, zirconium acrylametionate, zirconium malate, zirconium citrate, zirconium disopropylamine lactate, zirconium glycollate, zirconium triethanol amine glycollate, zirconium lactate glycollate, titanium lactate, titanium malate, titanium citrate, titanium ammonium lactate, titanium triethanolamine, and titanium acrylametionate, aluminum lactate, aluminum citrate, antimony compounds, chromium compounds, iron compounds, copper compounds, zinc compounds, and combinations thereof. In certain embodiments of the present invention, the crosslinking agent may be formulated to remain inactive until it is “activated” by, among other things, certain conditions in the fluid (e.g., pH, temperature, etc.) and/or interaction with some other substance. In some embodiments, the activation of the crosslinking agent may be delayed by encapsulation with a coating (e.g., a porous coating through which the crosslinking agent may diffuse slowly, or a degradable coating that degrades downhole) that delays the release of the crosslinking agent until a desired time or place. The choice of a particular crosslinking agent may be governed by several considerations that should be recognized by one skilled in the art, including, but not limited to, the following: the type of gelling agent included, the molecular weight of the gel diverting agents, the conditions in the subterranean formation being treated, the safety handling requirements, the pH of the treatment fluid, temperature, and/or the desired delay for the crosslinking agent to crosslink the gel diverting agents.

Examples of suitable degradable gel diverting agents may be “stimuli-degradable” and can be found in U.S. Pat. No. 7,306,040, the relevant disclosure of which is incorporated herein by reference. Stimuli that may lead to the degradation of stimuli-degradable gel diverting agents include any change in the condition or properties of the gel including, but not limited to, a change in pH (e.g., caused by the buffering action of the rock or the decomposition of materials that release chemicals such as acids) or a change in the temperature (e.g., caused by the contact of the fluid with the rock formation).

To form stimuli-degradable gel diverting agents, degradable crosslinkers may be used to crosslink gelling agents comprising “ethylenically unsaturated monomers.” Suitable gelling agents for stimuli-degradable gel diverting agents include, but are not limited to, ionizable monomers (such as 1-N,N-diethylaminomethylacrylate); diallyldimethylammonium chloride; 2-acrylamido-2-methyl propane sulfonate; acrylic acid; allylic monomers (such as di-allyl phthalate; di-allyl maleate; allyl dicyclohexyl carbonate; and the like); vinyl formate; vinyl acetate; vinyl propionate; vinyl butyrate; crotonic acid; itaconic acid acrylamide; methacrylamide; methacyrilonitrile; acrolein; methyl vinyl ether; ethyl vinyl ether; vinyl ketone; ethyl vinyl ketone; allyl acetate; allyl propionate; diethyl maleate; any derivative thereof; and any combination thereof.

In some embodiments, the degradable crosslinker for use in stimuli-degradable gel diverting agents may contain a degradable group(s) including, but not limited to, esters, phosphate esters, amides, acetics, ketals, orthoesters, carbamates, anhydrides, silyl ethers, alkene oxides, ethers, imines, ether esters, ester amides, ester urethanes, carbonate urethanes, amino acids, any derivative thereof, or any combination thereof. The choice of the degradable group may be determined by pH and temperature, the details of which are available in known literature sources. The unsaturated terminal groups may include substituted or unsubstituted ethylenically unsaturated groups, vinyl groups, allyl groups, acryl groups, or acryloyl groups, which are capable of undergoing polymerization with the above-mentioned gelling agents to form crosslinked gel diverting agents. Suitable degradable crosslinkers for stimuli-degradable gel diverting agents include, but are not limited to, unsaturated esters such as diacrylates, dimethacrylates, and dibutyl acrylates; acrylamides; ethers such as divinyl ethers; and combinations thereof. Specific examples include, but are not limited to, poly(ethylene glycol) diacrylate; polyethylene glycol dimethacrylate; polyethylene glycol divinyl ether; poly(ethylene glycol) divinyl ether; poly(ethylene glycol) diacrylate; poly(propylene glycol) dimethacrylate); bisacrylamide; and combinations thereof. In one embodiment, a stimuli-degradable crosslinking agent comprises one or more degradable crosslink and two vinyl groups. Some embodiments of these crosslinking agents are sensitive to changes in pH, such as ortho ester-based embodiments, acetate-based embodiments, ketal-based embodiments, and silicon-based embodiments. Generally speaking, at room temperature, the ortho ester-based embodiments should be stable at pHs of above 10, and should degrade at a pH below about 9; the acetate-based embodiments should be stable at pHs above about 8 and should degrade at pH below about 6; the ketal-based embodiments should be stable at pHs of about 7 and should degrade faster at a pH below 7; and the silicon-based embodiments should be stable at pHs above about 7 and should degrade faster in acidic media. Thus, under moderately acidic conditions (pH of around 3), the relative stability of these groups should decrease in the following order: amides>ketals>orthoester. At higher well bore temperatures, the more stable crosslinking groups contain amides or ethers and would be preferred over other choices including esters, acetics, and ketals.

The gel diverting agents may be present in the treatment fluids useful in the methods of the present invention in an amount sufficient to provide the desired viscosity. In some embodiments, the gel diverting agents may be present in an amount in the range of from a lower limit of about 0.1%, 0.15%, 0.25%, 0.5%, 1%, 5%, or 10% by weight of the treatment fluid to an upper limit of about 40%, 30%, 25%, or 10% by weight of the treatment fluid, and wherein the amount may range from any lower limit to any upper limit and encompass any subset therebetween.

When included, suitable crosslinking agents may be present in the treatment fluids useful in the methods of the present invention in an amount sufficient to provide the desired degree of crosslinking between molecules of the gel diverting agents. In certain embodiments, the crosslinking agent may be present in the first treatment fluids and/or sec-
ond treatment fluids of the present invention in an amount in the range of from about 0.005% to about 1% by weight of the treatment fluid. In certain embodiments, the crosslinking agent may be present in the treatment fluids of the present invention in an amount in the range of from about 0.05% to about 1% by weight of the first treatment fluid and/or the second treatment fluid. One of ordinary skill in the art, with the benefit of this disclosure, will recognize the appropriate amount of crosslinking agent to include in a treatment fluid of the present invention. Among other things, the temperature conditions of a particular application, the type of gel diverting agents used, the molecular weight of the gel diverting agents, the desired degree of viscosity modification, and/or the pH of the treatment fluid.

[0086] It should be noted that any derivative, any mixture, and any combination of the diverting agents described herein may be used as primary diverting agents or secondary diverting agents. Further, a primary diverting agent or a secondary diverting agent may be a hybrid of two or more diverting agents described herein.

[0087] In some embodiments, treatment fluids comprising gel diverting agents may include internal gel breakers such as enzyme, oxidizing, acid buffer, or delayed gel breakers. The gel breakers may cause the gel diverting agents of the present invention to revert to thin fluids that can be produced back to the surface, for example, after they have diverted fluid within a fracture network. In some embodiments, the gel breaker may be formulated to remain inactive until it is “activated” by, among other things, certain conditions in the fluid (e.g., pH, temperature, etc.) and/or interaction with other substances. In some embodiments, the gel breaker may be delayed by encapsulation with a coating (e.g., porous coatings through which the breaker may diffuse slowly, or a degradable coating that degrades downhole) that delays the release of the gel breaker. In other embodiments, the gel breaker may be a degradable material (e.g., polymeric acid or polyglycolic acid) that releases an acid or alcohol in the present of an aqueous liquid. In certain embodiments, the gel breaker used may be present in a treatment fluid in an amount in the range of from about 0.001% to about 200% by weight of the gelling agent. One of ordinary skill in the art, with the benefit of this disclosure, should recognize the type and amount of a gel breaker to include in certain treatment fluids of the present invention on, among other factors, the desired amount of delay time before the gel breaks, the type of gel diverting agents used, the temperature conditions of a particular application, the desired rate and degree of viscosity reduction, and/or the pH of the treatment fluid.

[0088] Degradable particulates for use in the present invention may have an average diameter of the diameter of the propping agents including, but not limited to, about 2 mesh to about 400 mesh on the U.S. Sieve Series. However, in certain circumstances, other mean particulate sizes may be desired and will be entirely suitable for practice of the present invention.

[0089] Degradable particles may comprise any materials suitable for use in a subterranean formation provided at least a portion of the degradable particulate is degradable. Suitable compositions include those disclosed herein for use in diverting agents including any derivative, any mixture, and any combination thereof. A nonlimiting example of a commercially available degradable particulate includes degradable particulates in the BIOVOID® series (degradable particles, available from Halliburton Energy Services, Inc.). Degradable particles may be self-degradable, stimulidegradable, or any combination thereof. In some embodiments, a treatment fluid may be introduced into the wellbore with an additive designed to initiate, accelerate, slow, or delay degradation of the degradable particles, in some embodiments, such an additive may be introduced simultaneously with the degradable particulates.

[0090] In certain embodiments, propping agents for use in the present invention may comprise a plurality of propellant particulates. Propellant particulates suitable for use in the present invention may comprise any material suitable for use in subterranean operations. Suitable materials for these propellant particulates include, but are not limited to, sand, bauxite, ceramic materials, glass materials, polymer materials, polytetrafluoroethylene materials, nut shell pieces, cured resinous particulates comprising nut shell pieces, seed shell pieces, cured resinous particulates comprising seed shell pieces, fruit pit pieces, cured resinous particulates comprising fruit pit pieces, wood, composite particulates, and combinations thereof. Suitable composite particulates may comprise a binder and a filler material wherein suitable filler materials include silica, alumina, fumed carbon, carbon black, graphite, mica, titanium dioxide, meta-silicate, calcium silicate, kaolin, talc, zirconia, boron, fly ash, hollow glass microspheres, solid glass, and combinations thereof. The mean particulate size generally may range from about 2 mesh to about 400 mesh on the U.S. Sieve Series, however, in certain circumstances, other mean particulate sizes may be desired and will be entirely suitable for practice of the present invention. In particular embodiments, preferred mean particulates size distribution ranges are one or more of 6/12, 8/16, 12/20, 16/30, 20/40, 30/50, 40/60, 50/70, or 50/70 mesh. A propellant particle may be any known shape of material, including substantially spherical materials, fibrous materials, polygonal materials (such as cubic materials), and combinations thereof. Moreover, fibrous materials, that may or may not be used to bear the pressure of a dosed fracture, may be included in certain embodiments of the present invention. In certain embodiments, the propellant particulates may be present in a treatment fluid for use in the present invention in an amount in the range of from about 0.1 pounds per gallon (“ppg”) to about 50 ppg by volume of the treatment fluid.

[0091] In some embodiments, a primary diverting agent, a secondary diverting agent, a degradable particulate, a propellant particulate, or any combination thereof may be coated with a consolidating agent. As used herein, the term “coating,” and the like, does not imply any particular degree of coating on the particulate. In particular, the terms “coat” or “coating” do not imply 100% coverage by the coating on the particulate. In some embodiments, a primary diverting agent, a secondary diverting agent, a degradable particulate, a propellant particulate, or any combination thereof may be coated with a consolidating agent prior to introduction into a wellbore, after introduction into a wellbore, simultaneous to introduction into a wellbore, or any combination thereof. In some embodiments, a coating, including degree of coating, may be used to control the rate of degradation of a primary diverting agent, a secondary diverting agent, a degradable particulate, a propellant particulate, or any combination thereof.

[0092] Consolidating agents suitable for use in the methods of the present invention generally comprise any compound that is capable of minimizing particulate migration. Nonlimiting examples of consolidating agents include SAND WEDGE® (an adhesive substance, available from Halliburton—
ton Energy Services, Inc.) and EXPEDIT® (a two-component resin system, available from Halliburton Energy Services, Inc.). In some embodiments, the consolidating agent may comprise a consolidating agent selected from the group consisting of: non-aqueous tackifying agents; aqueous tackifying agents; resins; silly-modified polyamide compounds; crosslinkable aqueous polymer compositions; and consolidating agent emulsions. Mixtures, combinations, and/or derivatives of these also may be suitable. The type and amount of consolidating agent included in a particular method of the present invention may depend upon, among other factors, the composition and/or temperature of the subterranean formation, the chemical composition of formation fluids, the flow rate of fluids present in the formation, the effective porosity and/or permeability of the subterranean formation, pore throat size and distribution, and the like. Furthermore, the concentration of the consolidating agent can be varied, inter alia, to either enhance bridging to provide for a more rapid coating of the consolidating agent or to minimize bridging to allow deeper penetration into the subterranean formation. It is within the ability of one skilled in the art, with the benefit of this disclosure, to determine the type and amount of consolidating agent to include in the methods of the present invention to achieve the desired results.

In some embodiments, the consolidating agent may comprise a consolidating agent emulsion that comprises an aqueous fluid, an emulsifying agent, and a consolidating agent. The consolidating agent in suitable emulsions may be either a non-aqueous tackifying agent or a resin. These consolidating agent emulsions have an aqueous external phase and organic-based internal phase. The term “emulsion” and any derivatives thereof as used herein refers to a combination of two or more immiscible phases and includes, but is not limited to, dispersions and suspensions.

Suitable consolidating agent emulsions comprise an aqueous external phase comprising an aqueous fluid. Suitable aqueous fluids that may be used in the consolidating agent emulsions of the present invention include freshwater, salt water, brine, seawater, or any other aqueous fluid that, preferably, does not adversely react with the other components used in accordance with this invention or with the subterranean formation. One should note, however, that if long-term stability of the emulsion is desired, a more suitable aqueous fluid may be one that is substantially free of salts. It is within the ability of one skilled in the art, with the benefit of this disclosure, to determine if and how much salt may be tolerated in the consolidating agent emulsions of the present invention before it becomes problematic for the stability of the emulsion. The aqueous fluid may be present in the consolidating agent emulsions in an amount in the range of about 20% to 99.9% by weight of the consolidating agent emulsion composition. In some embodiments, the aqueous fluid may be present in the consolidating agent emulsions in an amount in the range of about 60% to 99.9% by weight of the consolidating agent emulsion composition. In some embodiments, the aqueous fluid may be present in the consolidating agent emulsions in an amount in the range of about 95% to 99.9% by weight of the consolidating agent emulsion composition.

The consolidating agent in the emulsion may be either a non-aqueous tackifying agent or a resin. The consolidating agent may be present in a consolidating agent emulsion in an amount in the range of about 0.1% to about 40% by weight of the consolidating agent emulsion composition. In some embodiments, the consolidating agent may be present in a consolidating agent emulsion in an amount in the range of about 0.1% to about 5% by weight of the composition. As previously stated, the consolidating agent emulsions comprise an emulsifying agent. Examples of suitable emulsifying agents may include surfactants, proteins, hydrolyzed proteins, lipids, glycolipids, and nanosized particulates, including, but not limited to, fumed silica. Combinations of these may be suitable as well.

In some embodiments of the present invention, the consolidating agent may comprise a non-aqueous tackifying agent. A particularly preferred group of non-aqueous tackifying agents comprises polyanamides 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 a commercially available polycrystalline and polyanamide. Such commercial products include compounds such as combinations of dibasic acids containing some trimer and higher oligomers and also small amounts of monomer acids that are reacted with polyanamines. Other polycrystalline compounds are formed by acids, synthetic acids produced from fatty acids, maleic anhydride, acrylic acid, and the like. Combinations of these may be suitable as well.

Additional compounds which may be used as non-aqueous tackifying agents include liquids and solutions of, for example, polyesters, polycarbonates, silyl-modified polyanamide compounds, polycarbonates, urethanes, natural resins such as shellac, and the like. Combinations of these may be suitable as well.

Other suitable non-aqueous tackifying agents are described in U.S. Pat. Nos. 5,853,048 and 5,833,000, and U.S. Patent Publication Numbers 2007/0131425 and 2007/0131422, the relevant disclosures of which are herein incorporated by reference.

Non-aqueous tackifying agents suitable for use in the present invention may either be used such that they form a non-hardening coating on a surface or they may be combined with a multifunctional material capable of reacting with the non-aqueous tackifying agent to form a hardened coating. A “hardened coating” as used herein means that the reaction of the tackifying compound with the multifunctional material should result in a substantially non-flammable reaction product that exhibits a higher compressive strength in a consolidated agglomerate than the tackifying compound alone with the particulates. In this instance, the non-aqueous 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; dialdehydes such as glutaraldehyde; hemiacetals or aldehyde releasing compounds; dicarboxylic acids; dihydroxy acids; dichlorides and dibromides; polycrystalline anhydrides; epoxides; furfurals; aldehydehyd; aldheyde condensates; and silyl-modified polyanamide compounds; and the like; and combinations thereof. Suitable silyl-modified polyanamide compounds that may be used in the present invention are those that are substantially self-hardening compositions capable of at least partially adhering to a surface or to a particulate in the unhardened state, and that are further capable of self-hardening themselves to a substantially non-tacky state to which individual particulates such as formation fines will not adhere to,
for example, in formation or proppant pack pore throats. Such silyl-modified polyamides may be based, for example, on the reaction product of a silating compound with a polyamide or a combination of polyamides. The polyamide or combination of polyamides may be one or more polyamide intermediate compounds obtained, for example, from the reaction of a polyacid (e.g., diacid or higher) with a polyamine (e.g., diamine or higher) to form a polyamide polymer with the elimination of water.

In some embodiments of the present invention, the multifunctional material may be mixed with the tackifying compound in an amount of about 0.01% to about 50% by weight of the tackifying compound to effect formation of the reaction product. In other embodiments, the multifunctional material is present in an amount of about 0.5% to about 1% by weight of the tackifying compound. Suitable multifunctional materials are described in U.S. Pat. No. 5,839,510, the entire disclosure of which is herein incorporated by reference.

Aqueous tackifying agents suitable for use in the present invention are usually not generally significantly tacky when placed onto a particulate, but are capable of being “activated” (e.g., destabilized, coalesced and/or reacted) to transform the compound into a sticky, tackifying compound at a desirable time. Such activation may occur before, during, or after the aqueous tackifier agent is placed in the subterranean formation. In some embodiments, a pretreatment may be first contacted with the surface of a particulate to prepare it to be coated with an aqueous tackifier agent. Suitable aqueous tackifying agents are generally charged polymers that comprise compounds 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 tackifier agent may enhance the grain-to-grain contact between the individual particulates within the formation (be they diverting agents, proppant particulates, formation fines, or other particulates), helping bring about the consolidation of the particulates into a cohesive, flexible, and permeable mass.

Suitable aqueous tackifying agents include any polymer that can bind, coagulate, or flocculate a particulate. Also, polymers that function as pressure-sensitive adhesives may be suitable. 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 methacrylate)); 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; derivatives thereof, and combinations thereof. Methods of determining suitable aqueous tackifying agents and additional disclosure on aqueous tackifying agents can be found in U.S. Patent Publication Numbers 2005/0277554 and 2005/0274517, the entire disclosures of which are hereby incorporated by reference.

Some suitable tackifying agents are described in U.S. Pat. No. 5,249,627, the entire disclosure of which is incorporated herein by reference, which discloses aqueous tackifying agents that comprise at least one member selected from the group consisting of benzyl coco di-(hydroxyethyl) quaternary amine, p-T-amyl-phenol condensed with formaldehyde, and a copolymer comprising from about 80% to about 100% C1-30 alkylmethacrylate monomers and from about 0% to about 20% hydrophilic monomers. In some embodiments, the aqueous tackifying agent may comprise a copolymer that comprises from about 90% to about 99.5% 2-ethylhexylacrylate and from about 0.5% to about 10% acrylic acid. Suitable hydrophilic monomers may be any monomer that will provide polar oxygen-containing or nitrogen-containing groups. Suitable hydrophilic monomers include dialkyl amino alkyl(meth)acrylates and their quaternary addition and acid salts, acrylamide, N-(diakyl amino alkyl)acrylamide, methacrylamides and their quaternary addition and acid salts, hydroxy alkyl(meth)acrylates, unsaturated carboxylic acids such as methacrylic acid or acrylic acid, hydroxethyl acrylate, acrylamide, and the like. Combinations of these may be suitable as well. These copolymers can be made by any suitable emulsion polymerization technique. Methods of producing these copolymers are disclosed, for example, in U.S. Pat. No. 4,670,501, the entire disclosure of which is incorporated herein by reference.

In some embodiments of the present invention, the consolidating agent may comprise a resin. The term “resin” as used herein refers to any of numerous physically similar polymerized synthetics or chemically modified natural resins including thermoplastic materials and thermosetting materials. Resins that may be suitable for use in the present invention may include substantially all resins known and used in the art.

One type of resin suitable for use in the methods of the present invention is a two-component epoxy-based resin comprising a liquid hardenable resin component and a liquid hardening agent component. The liquid hardenable resin component comprises 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 if 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, the surrounding weather conditions, and the desired long-term stability of the consolidating agent. An alternate way to reduce the viscosity of the hardenable resin is to heat it. The second component is the liquid hardening agent component, which comprises a hardening agent, an optional silane coupling agent, a surfactant, an optional hydrolyzable ester for, among other things, breaking gelled fracturing fluid films on particulates, and an optional liquid carrier fluid for, among other things, reducing the viscosity of the hardening agent component.

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 diglycidyl ether resins, butoxymethyl butyl glycidyl ether resins, bisphenol A-epichlorhydrin resins, bisphenol F resins, polycryloxyresins, novolak resins, polyester resins, phenol-aldehyde resins, urea-aldehyde resins, furan resins, urethane resins, glycidyl ether resins, other epoxide resins, and combinations thereof. In some embodiments, the hardenable resin may comprise a urethane resin. Examples of suitable urethane resins may comprise a polyisocyanate component and a poly-
hydroxy component. Examples of suitable hardenable resins, including urethane resins, that may be suitable for use in the methods of the present invention include those described in U.S. Pat. Nos. 4,585,064; 6,582,819; 6,677,426; and 7,153,575, the entire disclosures of which are herein incorporated by reference.

[0109] The hardenable resin may be included in the liquid hardenable resin component in an amount in the range of about 5% to about 100% by weight of the liquid hardenable resin component. It is within the ability of one skilled in the art, with the benefit of this disclosure, to determine how much of the liquid hardenable resin component may be needed to achieve the desired results. Factors that may affect this decision include which type of liquid hardenable resin component and liquid hardening agent component are used.

[0110] Any solvent that is compatible with the hardenable resin and achieves the desired viscosity effect may be suitable for use in the liquid hardenable resin component. Suitable solvents may include butyl lactate, dipropylene glycol methyl ether, dipropylene glycol dimethyl ether, dimethyl fomamide, diethylene glycol methyl ether, ethylene glycol butyl ether, diethylene glycol butyl ether, propylene carbonate, methanol, butyl alcohol, d’limonene, fatty acid methyl esters, and butyglycidyl ether, and combinations thereof. Other preferred solvents may include aqueous dissolvable solvents such as methanol, isopropanol, butanol, and glycol ether solvents, and combinations thereof. Suitable glycol ether solvents include, but are not limited to, diethylene glycol methyl ether, dipropylene glycol methyl ether, 2-butoxy ethanol, ethers of a C2 to C6 dihydric alkane containing at least one C1 to C6 alkyl group, mono ethers of dihydric alkanols, methoxypropanol, butoxyethanol, and hexoxyethanol, and isomers thereof. Selection of an appropriate solvent is dependent on the resin composition chosen and is within the ability of one skilled in the art, with the benefit of this disclosure.

[0111] As described above, use of a solvent in the liquid hardenable resin component is optional but may be desirable to reduce the viscosity of the hardenable resin component for ease of handling, mixing, and transferring. However, as previously stated, it may be desirable in some embodiments to not use such a solvent for environmental or safety reasons. It is within the ability of one skilled in the art, with the benefit of this disclosure, to determine if and how much solvent is needed to achieve a suitable viscosity. In some embodiments, the amount of the solvent used in the liquid hardenable resin component may be in the range of about 0.1% to about 50% by weight of the liquid hardenable resin component. Option-ally, the liquid hardenable resin component may be heated to reduce its viscosity, in place of, or in addition to, using a solvent.

[0112] Examples of the hardening agents that can be used in the liquid hardening agent component include, but are not limited to, cycloaliphatic amines, such as piperazine, derivatives of piperazine (e.g., aminoethylpiperazine) and modified piperazines; aromatic amines, such as methylenedianiline, derivatives of methylene dianiline and hydrogenated forms, and 4,4’-diaminodiphenyl sulfone; aliphatic amines, such as ethylene diamine, diethylene triamine, triethylene tetraamine, and tetraethylene pentamine; imidazole; pyrazole; pyrazine; pyrimidine; pyridazine; 1H-indazole; purine; phthalazine; naphthylidine; quinoline; quinazoline; phena-zine; imidazolide; cinnoline; imidazole; 1,3,5-triazine; thiazole; pteridine; indazole; amines; polyamines; amides; polyamides; and 2-ethyl-4-methylimidazole; and combinations thereof. The chosen hardening agent often effects the range of temperatures over which a hardenable resin is able to cure. By way of example, and not of limitation, in subterranean formations having a temperature of about 60° F. to about 250° F., amines and cyclic-aliphatic amines such as piperidine, triethylamine, tris(dimethylaminomethyl)phenol, and dimethylaminomethyl)phenol may be preferred. In subterranean formations having higher temperatures, 4,4’-diamino- diphenyl sulfone may be a suitable hardening agent. Harden- ing agents that comprise piperazine or a derivative of piperazine have been shown capable of curing various hardenable resins from temperatures as low as about 50° F. to as high as about 350° F.

[0113] The hardening agent may be included in the liquid hardening agent component in an amount sufficient to at least partially harden the resin composition. In some embodiments of the present invention, the hardening agent used is included in the liquid hardening agent component in the range of about 0.1% to about 95% by weight of the liquid hardening agent component. In other embodiments, the hardening agent used may be included in the liquid hardening agent component in an amount of about 15% to about 85% by weight of the liquid hardening agent component. In other embodiments, the hardening agent may be included in the liquid hardening agent component in an amount of about 15% to about 55% by weight of the liquid hardening agent component.

[0114] In some embodiments, the consolidating agent may comprise a liquid hardenable resin component emulsified in a liquid hardening agent component, wherein the liquid hardenable resin component is the internal phase of the emulsion and the liquid hardening agent component is the external phase of the emulsion. In other embodiments, the liquid hardenable resin component may be emulsified in water and the liquid hardening agent component may be present in the water. In other embodiments, the liquid hardenable resin component may be emulsified in water and the liquid hardening agent component may be provided separately. Similarly, in other embodiments, both the liquid hardenable resin component and the liquid hardening agent component may both be emulsified in water.

[0115] The optional silane coupling agent may be used, among other things, to act as a mediator to help bond the resin to particulates. Examples of suitable silane coupling agents include, but are not limited to, N-2-(aminomethyl)-3-aminopropyltrimethoxysilane, and 3-glycidoxypropyltrimethoxysilane, and combinations thereof. The silane coupling agent may be included in the resin component or the liquid hardening agent component (according to the chemistry of the particular group as determined by one skilled in the art with the benefit of this disclosure). In some embodiments of the present invention, the silane coupling agent used is included in the liquid hardening agent component in the range of about 0.1% to about 3% by weight of the liquid hardening agent component.

[0116] Any surfactant compatible with the hardening agent and capable of facilitating the coating of the resin onto particulates in the subterranean formation may be used in the liquid hardening agent component. Such surfactants include, but are not limited to, an alkyl phosphate surfactant (e.g., a C12-C14 alkyl phosphate surfactant), an ethoxylated nonyl phenol phosphate ester, one or more cationic surfactants, and one or more nonionic surfactants. Combinations of one or more cationic and nonionic surfactants also may be suitable.
Examples of such surfactant combinations are described in U.S. Pat. No. 6,311,773, the relevant disclosure of which is incorporated herein by reference. The surfactant or surfac- tants that may be used are included in the liquid hardening agent component in an amount in the range of about 1% to about 10% by weight of the liquid hardening agent component.

While not required, examples of hydrolyzable esters that may be used in the liquid hardening agent component include, but are not limited to, a combination of dimethylfuran tarate, dimethyl adipate, and dimethyl succinate; dimethyl furo- late; methyl salicylate; dimethyl salicylate; and dimethyl succinate; and combinations thereof. When used, a hydrolyzable ester is included in the liquid hardening agent component in an amount in the range of about 0.1% to about 2.5% by weight of the liquid hardening agent component.

Use of a diluent or liquid carrier fluid in the liquid hardening agent component is optional and may be used to reduce the viscosity of the liquid hardening agent component for ease of handling, mixing, and transferring. As previously stated, it may be desirable in some embodiments to not use such a solvent for environmental or safety reasons. Any suit- able carrier fluid that is compatible with the liquid hardening agent component and achieves the desired viscosity effects is suitable for use in the present invention. Some suitable liquid carrier fluids are those having high flash points (e.g., about 125°F) because of, among other things, environmental and safety concerns; such solvents include, but are not limited to, butyl lactate, dipropylene glycol methyl ether, di- propylene glycol dimethyl ether, dimethyl formamide, diethylenglycol methyl ether, ethylenglycol butyl ether, diethyleneglycol butyl ether, propylene carbonate, methanol, butyl alcohol, d-limonene, and fatty acid methyl esters, and combinations thereof. Other suitable liquid carrier fluids include aqueous dissoluble solvents such as, for example, methanol, isopro- panol, butanol, glycol ether solvents, and combinations thereof. Suitable glycol ether liquid carrier fluids include, but are not limited to, diethylene glycol methyl ether, dipropylene glycol methyl ether, 2-butoxy ethanol, ethers of a C2 to C6 dihydric alkanol having at least one C1 to C6 alkyl group, mono ethers of dihydric alkanols, methoxypropyl, butoxy- ethanols, and hexoxethanol, and isomers thereof. Combinations of these may be suitable as well. Selection of an appro- priate liquid carrier fluid is dependent on, inter alia, the resin composition chosen.

Other resins suitable for use in the present invention are furan-based resins. Suitable furan-based resins include, but are not limited to, furfuryl alcohol resins, furfural resins, combinations of furfuryl alcohol resins and aldehydes, and a combination of furan resins and phenolic resins. Of these, furfuryl alcohol resins may be preferred. A furan-based resin may be combined with a solvent to control viscosity if desired. Suitable solvents for use in the furan-based consolidating compositions of the present invention are applicable in an amount in the range of about 0.1% to about 70% by weight, based on the weight percent of the resin.

In embodiments, the furan-based resins suitable for use in the present invention are capable of enduring temperatures well in excess of 350°F without degrading. In some embodiments, the furan-based resins suitable for use in the present invention are capable of enduring temperatures up to about 750°F without degrading.

Optionally, the furan-based resins suitable for use in the present invention may further comprise a curing agent to facilitate or accelerate curing of the furan-based resin at lower temperatures. The presence of a curing agent may be particularly useful in embodiments where the furan-based resin may be placed within subterranean formations having temperatures below about 350°F. Examples of suitable curing agents include, but are not limited to, organic or inorganic acids, such as, inter alia, maleic acid, fumaric acid, sodium bisul- fite, hydrochloric acid, hydrofluoric acid, acetic acid, formic acid, phosphoric acid, sulfuric acid, alkyl benzene sulfonic acids such as toluene sulfonic acid and dodecyl benzene sulfonic acid (“DDBSA”), and combinations thereof. In those embodiments where a curing agent is not used, the furan- based resin may cure autocatalytically.

Still other resins suitable for use in the methods of the present invention are phenolic-based resins. Suitable phe- nolic-based resins include, but are not limited to, terpolymers of phenol, phenolic formaldehyde resins, and a combination of phenolic and furan resins. In some embodiments, a combination of phenolic and furan resins may be preferred. A phenolic-based resin may be combined with a solvent to control viscosity if desired. Suitable solvents for use in the present invention include, but are not limited to, butyl acetate, butyl lactate, furfuryl acetate, and 2-butoxy ethanol. Of these, 2-butoxy ethanol may be preferred in some embodiments.

Yet another resin-type material suitable for use in the methods of the present invention is a phenol/phenol formal-dehyde/furfuryl alcohol resin comprising of about 5% to about 30% phenol, of about 40% to about 70% phenol formal- aldehyde, of about 10% to about 40% furfuryl alcohol, of about 0.1% to about 3% of a silane coupling agent, and of 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, and 3-glycidoxypropyltrimethoxysilane. Suitable surfactants include, but are not limited to, an ethoxylated nonyl phenol phosphate ester, combinations of one or more cationic surfactants, and one or more nonionic surfactants and an alkyl phosphonate surfactant.

In some embodiments, resins suitable for use in the consolidating agent emulsion compositions of the present invention may optionally comprise filler particles. Suitable filler particles may include any particle that does not adversely react with the other components used in accordance with this invention or with the subterranean formation. Examples of suitable filler particles include silica, glass, clay, alumina, fumed silica, carbon black, graphite, mica, meta-silicate, calcium silicate, calcium, kaoline, talc, zirconia, titania- nium dioxide, fly ash, and boron, and combinations thereof. In some embodiments, the filler particles may range in size of about 0.01 μm to about 100 μm. As will be understood by one skilled in the art, particles of smaller average size may be particularly useful in situations where it is desirable to obtain high proppant pack permeability (i.e., conductivity), and/or high consolidation strength. In certain embodiments, the filler particles may be included in the resin composition in an amount of about 0.1% to about 70% by weight of the resin.
In other embodiments, the filler particles may be included in the resin composition in an amount of about 0.5% to about 40% by weight of the resin composition. In some embodiments, the filler particles may be included in the resin composition in an amount of about 1% to about 10% by weight of the resin composition. Some examples of suitable resin compositions comprising filler particles are described in U.S. Patent Publication Number 2008/0006405, the entire disclosure of which is herein incorporated by reference.

Silyl-modified polyamide compounds may be described as substantially self-hardening compositions that are capable of at least partially adhering to particulates in the unhardenable state, and that are further capable of self-hardening themselves to a substantially non-tacky state to which individual particulates such as formation fines will not adhere to, for example, in formation or proppant pack pore throats. Such silyl-modified polyamides may be based, for example, on the reaction product of a silating compound with a polyamide or a combination of polyamides. The polyamide or combination of polyamides may be one or more polyamide intermediate compounds obtained, for example, from the reaction of a polyacid (e.g., diacid or higher) with a polynylene (e.g., diamine or higher) to form a polyamide polymer with the elimination of water. Other suitable silyl-modified polyamides and methods of making such compounds are described in U.S. Pat. No. 6,439,309, the relevant disclosure of which is herein incorporated by reference.

In other embodiments, the consolidating agent comprises 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 gel 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 freshwater, 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. The most suitable polymers are those that would absorb or adhere to the rock surfaces so that the rock matrix may be strengthened without occupying a lot of the pore space and/or reducing permeability. Examples of suitable acrylamide-containing polymers include polyacrylamide, partially hydrolyzed polyacrylamide, copolymers of acrylamide and acrylate, and carboxylate-containing terpolymers and tetrapolymers of acrylate. Combinations of these may be suitable as well. 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, glucose, galactose, xyllose, 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. Combinations of these may be suitable as well. Suitable hydratable synthetic polymers and copolymers that may be used in the crosslinkable aqueous polymer compositions include, but are not limited to, polycarboxylates such as polycarboxylates and polymethacrylates; polyacrylamides; methylvinyl ether polymers; polyvinyl alcohols; and polyvinylpyrrolidone. Combinations of these may be suitable as well. 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 may be 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 may be 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 acid 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, among other things, the desired degree of crosslinking. In some embodiments of the present invention, the crosslinking agent may be present in the crosslinkable aqueous polymer compositions of the present invention in an amount in the range of from about 0.1% 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, among other things, 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.

In other embodiments, the consolidating agents useful in the methods 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.

[0132] 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-methylpropene sulfonic acid, dimethylacrylamide, vinyl sulfonic acid, N,N-dimethylaminoethylmethacrylate, 2-triethylammoniummethyilmethacrylate chloride, N,N-dimethylaminopropylmethacrylamide, methacrylamidepropyltriethylenammonium chloride, N-vinyl pyrrolidone, vinyl-phosphonic acid, and methacryloyloxyethyl trimethylammonium sulfate, and combinations thereof. In some embodiments, the water-soluble polymerizable organic monomer should be self-crosslinking. Examples of suitable monomers which are thought to be self crosslinking include, but are not limited to, hydroxyethyl acrylate, hydroxymethylacrylate, hydroxyethylmethacrylate, N-hydroxymethylacrylamide, N-hydroxymethylmethacrylamide, polyethylene glycol acrylic, polyethylene glycol methacrylate, polypropylene glycol acrylate, and polypropylene glycol methacrylate, and combinations thereof. One of these, hydroxethylacrylate may be preferred in some instances. An example of a particularly suitable monomer is hydroxyethylcellulose-vinyl phosphonic acid. The water-soluble polymerizable organic monomer (or monomers where a combination 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 may be 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 may be 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.

[0133] 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 predissolved 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.

[0134] A primary initiator may be used, among other things, to initiate polymerization of the water-soluble polymerizable organic monomer(s). Any compound or compounds that form free radicals in aqueous solution may be used as the primary initiator. The free radicals act, among other things, 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. Suitable azo polymerization initiators include 2,2’-azobisis(2-imidazole-2-hydroxyethyl)propane, 2,2’-azobisis(2-aminopropane), 4,4’-azobisis(4-cyanovlaric acid), and 2,2’-azobisis(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 may be 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, with the benefit of this disclosure, will recognize that as the polymerization temperature increases, the required level of activator decreases.

[0135] 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).

[0136] Also optionally, the polymerizable organic monomer compositions of the present invention may further 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 suitable 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.

[0137] In some embodiments, a treatment fluid may comprise a base fluid selected from an oil-based fluid, an aqueous-based fluid, a water-in-oil emulsion, or an oil-in-water emulsion. In some embodiments, the base fluid may vary for the different steps described above. In such embodiments, one
skilled in the art should understand that a pill may optionally need to be inserted between steps to properly change base fluids.

[0138] Suitable oil-based fluids may include an alkane, an olefin, an aromatic organic compound, a cyclic alkane, a paraffin, a diesel fluid, a mineral oil, a desulfurized hydrogenated kerosene, and any combination thereof. Examples of suitable invert emulsions include those disclosed in U.S. Pat. Nos. 5,905,061; 5,977,031; and 6,828,279, each of which are incorporated herein by reference. Aqueous base fluids suitable for use in the treatment fluids of the present invention may comprise fresh water, saltwater (e.g., water containing one or more salts dissolved therein), brine (e.g., saturated salt water), seawater, or combinations thereof. Generally, the water may be from any source, provided that it does not contain components that might adversely affect the stability and/or performance of the first treatment fluids or second treatment fluids of the present invention. In certain embodiments, the density of the aqueous base fluid can be adjusted, among other purposes, to provide additional particulate transport and suspension in the treatment fluids used in the methods of the present invention. In certain embodiments, the pH of the aqueous base fluid may be adjusted (e.g., by a buffer or other pH adjusting agent), among other purposes, to activate a crosslinking agent and/or to reduce the viscosity of the first treatment fluid (e.g., activate a breaker, deactivate a crosslinking agent). In these embodiments, the pH may be adjusted to a specific level, which may depend on, among other factors, the types of gelling agents, acids, and other additives included in the treatment fluid. One of ordinary skill in the art, with the benefit of this disclosure, will recognize when such density and/or pH adjustments are appropriate.

[0139] In some embodiments, a treatment fluid for use in the present invention may further comprise an additive including, but not limited to, a salt; a weighting agent; an inert solid; a fluid loss control agent; an emulsifier; a dispersion aid; a corrosion inhibitor; an emulsion thinner; an emulsion thickener; a viscosity reducing agent; a high-pressure, high-temperature emulsifier-filtration control agent; a surfactant; a particulate; a lost circulation material; a foaming agent; a gas; a pH control additive; a breaker; a biocide; a crosslinker; a stabilizer; a chelating agent; a scale inhibitor; a mutual solvent; an oxidizer; a reducer; a friction reducer; a clay stabilizing agent; and any combination thereof.

[0140] In some embodiments, the present invention provides for treating a subterranean formation to support a fracture network having at least one access conduit to the subterranean formation from a wellbore. Treating the subterranean formation may include the steps, not necessarily in this order or performed independently, placing a first treatment fluid into the subterranean formation through the at least one access conduit at a pressure sufficient to form at least a portion of a fracture network extending from the at least one access conduit; pumping a second treatment fluid comprising a propping agent into the fracture network such that the primary diverting agent substantially inhibits fluid flow through the access conduit.

[0141] In some embodiments, the present invention provides for treating a subterranean formation having a closure pressure greater than about 500 psi and having at least one access conduit to the subterranean formation from a wellbore. Treating the subterranean formation may include the steps, not necessarily in this order or performed independently, placing a first treatment fluid into the subterranean formation through the at least one access conduit at a pressure sufficient to form at least a portion of a fracture network extending from the at least one access conduit; pumping a second treatment fluid comprising a propping agent into the fracture network such that the propping agent forms a proppant pack in at least a portion of the fracture network; placing a third treatment fluid comprising a secondary diverting agent into the wellbore; and placing a fourth treatment fluid comprising a primary diverting agent into the wellbore such that the primary diverting agent substantially inhibits fluid flow through the access conduit.

[0142] In some embodiments, the present invention provides for treating a subterranean formation able to support a fracture network having at least one access conduit to the subterranean formation from a wellbore. Treating the subterranean formation may include the steps, not necessarily in this order or performed independently, placing a first treatment fluid into the subterranean formation at a pressure sufficient to form at least a portion of a fracture network extending from at least one access conduit; pumping a second treatment fluid comprising a propping agent into the fracture network such that the propping agent forms a proppant pack in at least a portion of the fracture network, wherein the propping agent comprises proppant particulates at least partially coated with a consolidating agent and at least a portion of a fluid flow through the access conduit; and placing a third treatment fluid comprising a secondary diverting agent into the wellbore such that the secondary diverting agent goes through the access conduit and into at least a portion of the fracture network such as to substantially inhibit fluid flow through at least a portion of the fracture network without substantially inhibiting fluid flow through the access conduit, wherein the secondary diverting agent is at least partially degradable; placing a fourth treatment fluid comprising a primary diverting agent into the wellbore such that the primary diverting agent substantially inhibits fluid flow through the access conduit, wherein the primary diverting agent is at least partially degradable; and repeating at least one step selected from the group consisting of pumping the second treatment fluid, placing the third treatment fluid, placing the fourth treatment fluid, placing the fifth treatment fluid, and any combination thereof.
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, combined, or modified and all such variations are considered within the scope and spirit of the present invention. The invention illustratively disclosed herein suitably may be practiced in the absence of any element which is not specifically disclosed herein. While compositions and methods are described in terms of “comprising,” “containing,” or “including” various components or steps, the compositions and methods can also “consist essentially of” or “consist of” the various components and steps. All numbers and ranges disclosed above may vary by some amount. Whenever a numerical range with a lower limit and an upper limit is disclosed, any number and any included range falling within the range is specifically disclosed. In particular, every range of values (of the form, “from a to b,” or, equivalently, “from approximately a to b,” or, equivalently, “from approximately a-b”) disclosed herein is to be understood to set forth every number and 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. Moreover, the indefinite articles “a” or “an,” as used in the claims, are defined herein to mean one or more than one of the element that it introduces. If there is any conflict in the usages of a word or term in this specification and one or more patent or other documents that may be incorporated herein by reference, the definitions that are consistent with this specification should be adopted.

The invention claimed is:

1. A method comprising:
   providing a wellbore penetrating a subterranean formation, wherein the subterranean formation is able to support a fracture network;
   providing at least one access conduit to the subterranean formation from the wellbore;
   placing a first treatment fluid into the subterranean formation through at least one access conduit at a pressure sufficient to form at least a portion of a fracture network extending from at least one access conduit;
   pumping a second treatment fluid comprising a propping agent into the fracture network such that the propping agent forms a proppant pack in at least a portion of the fracture network;
   placing a third treatment fluid comprising a secondary diverting agent into the wellbore such that the secondary diverting agent goes through the access conduit and into at least a portion of the fracture network so as to substantially inhibit fluid flow through at least a portion of the fracture network without substantially inhibiting fluid flow through the access conduit; and
   placing a fourth treatment fluid comprising a primary diverting agent into the wellbore such that the primary diverting agent substantially inhibits fluid flow through the access conduit.

2. The method of claim 1 further comprising:
   producing hydrocarbons from the subterranean formation.

3. The method of claim 1, wherein pumping the second treatment fluid, placing the third treatment fluid, and placing the fourth treatment fluid are performed in any order.

4. The method of claim 1, wherein pumping the second treatment fluid is done continuously while placing the third treatment fluid and placing the fourth treatment fluid.

5. The method of claim 1, wherein the concentration of the propping agent in the second treatment fluid is changed during pumping.

6. The method of claim 1, wherein a step selected from the group consisting of pumping the second treatment fluid, placing the third treatment fluid, placing the fourth treatment fluid, and any combination thereof are performed more than once.

7. The method of claim 1, wherein the first treatment fluid, the second treatment fluid, the third treatment fluid, and the fourth treatment fluid comprise the same base fluid with different additives.

8. The method of claim 1, wherein the propping agent comprises a proppant particulate coated with a consolidating agent.

9. The method of claim 1, wherein the secondary diverting agent has a diameter of about 150 microns or less.

10. The method of claim 1, wherein the secondary diverting agent is at least partially degradable.

11. The method of claim 1, wherein the primary diverting agent has a bimodal particle size distribution.

12. The method of claim 1, wherein the primary diverting agent comprises first particulates, wherein the secondary diverting agent comprises second particles, and wherein the first particles have a larger average diameter than the second particulates.

13. The method of claim 1, wherein the primary diverting agent comprises proppant.

14. The method of claim 1, wherein the primary diverting agent comprises a gel.

15. The method of claim 1, wherein the primary diverting agent is at least partially degradable.

16. The method of claim 1 further comprising:
   introducing a cleanup treatment fluid into the wellbore to enhance fluid flow through at least a portion of the fracture network.

17. The method of claim 1 further comprising:
   placing a fifth treatment fluid comprising a degradable particle into the fracture network such that the degradable particle is capable of forming voids within at least a portion of the proppant pack.

18. The method of claim 17, wherein placing a fifth treatment fluid and pumping a second treatment fluid are performed simultaneously.

19. The method of claim 17, wherein the fifth treatment fluid further comprises the propping agent.

20. The method of claim 17 further comprising:
   introducing a cleanup treatment fluid into the wellbore to enhance fluid flow through at least a portion of the fracture network.

21. The method of claim 17, wherein a step selected from the group consisting of pumping the second treatment fluid, placing the third treatment fluid, placing the fourth treatment fluid, placing a fifth treatment fluid, and any combination thereof is performed more than once.

22. A method comprising:
   providing a wellbore penetrating a subterranean formation, wherein the subterranean formation has a closure pressure greater than about 500 psi;
   providing at least one access conduit to the subterranean formation from the wellbore;
placing a first treatment fluid into the subterranean formation through the at least one access conduit at a pressure sufficient to form at least a portion of a fracture network extending from the at least one access conduit;
pumping a second treatment fluid comprising a propping agent into the fracture network such that the propping agent forms a proppant pack in at least a portion of the fracture network;
placing a third treatment fluid comprising a secondary diverting agent into the wellbore such that the secondary diverting agent goes through the access conduit and into at least a portion of the fracture network so as to substantially inhibit fluid flow through at least a portion of the fracture network without substantially inhibiting fluid flow through the access conduit; and
placing a fourth treatment fluid comprising a primary diverting agent into the wellbore such that the primary diverting agent substantially inhibits fluid flow through the access conduit.

23. A method comprising:
providing a wellbore penetrating a subterranean formation, wherein the subterranean formation is able to support a fracture network and the wellbore has at least one access conduit to the subterranean formation from the wellbore;
placing a first treatment fluid into the subterranean formation at a pressure sufficient to form at least a portion of a fracture network extending from at least one access conduit;
pumping a second treatment fluid comprising a propping agent into the fracture network such that the propping agent forms a proppant pack in at least a portion of the fracture network,
wherein the propping agent comprises proppant particles at least partially coated with a consolidating agent and at least a portion of degradable particles;
placing a third treatment fluid comprising a secondary diverting agent into the wellbore such that the secondary diverting agent goes through the access conduit and into at least a portion of the fracture network so as to substantially inhibit fluid flow through at least a portion of the fracture network without substantially inhibiting fluid flow through the access conduit,
wherein the secondary diverting agent is at least partially degradable;
placing a fourth treatment fluid comprising a primary diverting agent into the wellbore such that the primary diverting agent substantially inhibits fluid flow through the access conduit,
wherein the primary diverting agent is at least partially degradable; and
repeating at least one step selected from the group consisting of pumping the second treatment fluid, placing the third treatment fluid, placing the fourth treatment fluid, placing the fifth treatment fluid, and any combination thereof.

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