The present invention relates to systems and methods useful in subterranean treatment operations. More particularly, the present invention relates to systems and methods for treating subterranean formations using low-molecular-weight fluids. Examples of methods of the present invention include methods of treating a subterranean formation intersected by a wellbore; methods of enhancing production from multiple subterranean formations penetrated by a wellbore during a single trip through the wellbore; methods of enhancing production, in real time, from multiple subterranean formations penetrated by a wellbore during a single trip through the wellbore; and methods of reducing the cost of enhancing production from multiple formations penetrated by a wellbore by stimulating multiple formations, on a single trip through the wellbore, with a fluid that minimizes damage to the formation.
METHODS OF TREATING SUBTERRANEAN FORMATIONS USING LOW-MOLECULAR-WEIGHT FLUIDS

BACKGROUND OF THE INVENTION TECHNOLOGY

[0001] The present invention relates to systems and methods useful in subterranean treatment operations. More particularly, the present invention relates to systems and methods for treating subterranean formations using low-molecular weight treatment fluids.

[0002] Hydrocarbon-bearing subterranean formations penetrated by well bores often may be treated to increase their permeability or conductivity, and thereby facilitate greater hydrocarbon production therefrom. One such production stimulation treatment, known as “fracturing,” involves injecting a treatment fluid (e.g., a “fracturing fluid”) into a subterranean formation or zone at a rate and pressure sufficient to create or enhance at least one fracture therein. Fracturing fluids commonly comprise a proppant material (e.g., sand, or other particulate material) suspended within the fracturing fluid, which may be deposited into the created fractures. The proppant material functions, inter alia, to prevent the formed fractures from re-closing upon termination of the fracturing operation. Upon placement of the proppant in the formed fractures, conductive channels may remain within the zone or formation, through which channels produced fluids readily may flow to the well bore upon completion of the fracturing operation.

[0003] Because most fracturing fluids should suspend proppant material, the viscosity of fracturing fluids often has been increased through inclusion of a viscosifier. After a viscosified fracturing fluid has been pumped into the formation to create or enhance at least one fracture therein, the fracturing fluid generally may be “broken” (e.g., caused to revert into a low viscosity fluid), to facilitate its removal from the formation. The breaking of viscosified fracturing fluids commonly has been accomplished by including a breaker within the fracturing fluid.

[0004] Conventional fracturing fluids usually are water-based liquids containing a viscosifier that comprises a polysaccharide (e.g., guar gum). Guar, and derivatized guar polymers such as hydroxypropyl guar, are water-soluble polymers that may be used to create high viscosity in an aqueous fracturing fluid, and that readily may be crosslinked to further increase the viscosity of the fracturing fluid. While the use of gelled and crosslinked polysaccharide-containing fracturing fluids has been successful, such fracturing fluids often have not been thermally stable at temperatures above about 200°F. That is, the viscosity of the highly viscous gelled and crosslinked fluids may decrease over time at high temperatures. To offset the decreased viscosity, the concentration of the viscosifier often may be increased, which may result in, inter alia, increased costs and increased friction pressure in the tubing through which the fracturing fluid is injected into a subterranean formation. This may increase the difficulty of pumping the fracturing fluids. Thermal stabilizers, such as sodium thiosulfate, often have been included in fracturing fluids, inter alia, to scavenge oxygen and thereby increase the stabilities of fracturing fluids at high temperatures. However, the use of thermal stabilizers also may increase the cost of the fracturing fluids.

[0005] Certain types of subterranean formations, such as certain types of shales and coals, may respond unfavorably to fracturing with conventional fracturing fluids. For example, in addition to opening a main, dominant fracture, the fracturing fluid may further invade numerous natural fractures (or “butts” and “cleats,” where the formation comprises coal) that may intersect the main fracture, which may cause conventional viscosifiers within the fracturing fluid to invade intersecting natural fractures. When the natural fractures re-close at the conclusion of the fracturing operation, the conventional viscosifiers may become trapped therein, and may obstruct the flow of hydrocarbons from the natural fractures to the main fracture. Further, even in circumstances where the viscosifier does not become trapped within the natural fractures, a thin coating of gel nevertheless may remain on the surface of the natural fractures after the conclusion of the fracturing operation. This may be problematic, inter alia, where the production of hydrocarbons from the subterranean formation involves processes such as desorption of the hydrocarbon from the surface of the formation. Previous attempts to solve these problems have involved the use of less viscous fracturing fluids, such as non-gelled water. However, this may be problematic, inter alia, because such fluids may prematurely dilate natural fractures perpendicular to the main fracture in a problem often referred to as “near well bore fracture complexity,” or “near well bore tortuosity.” This may be problematic because the creation of multiple fractures, as opposed to one or a few dominant fractures, may result in reduced penetration into the formation, e.g., for a given injection rate, many short fractures may be created rather than one, or a few, lengthy fracture(s). This may be problematic because in low permeability formations, the driving factor to increase productivity often is the fracture length. Furthermore, the use of less viscous fracturing fluids also may require excessive fluid volumes, and/or excessive injection pressure. Excessive injection pressure may frustrate attempts to place proppant into the fracture, thereby reducing the likelihood that the fracturing operation will increase hydrocarbon production.

[0006] It often is desirable to selectively treat hydrocarbon zones, or formations, to extract hydrocarbons therefrom while isolating the formation from other intervals in a well bore. A packer may be used to isolate a section of the well bore that may be either above, or below the packer. Once a particular operation, for example a fracturing operation, has been performed, it may be desirable to unset or release the packer and move it to another location in the wellbore and set the packer again to isolate another section of the wellbore. Generally, a pressure differential across the packer element will exist after an operation in the wellbore is performed. For example, when fracturing fluid pumped through a work string is communicated with the wellbore adjacent a formation, the pressure above the packer element, which will be located below the formation, will be higher than the pressure below the packer element after the operation is performed. In order to unset the packer, the pressure above and below the packer element which engages the casing must be equalized. Normally, in order to equalize the pressure, the formation must be allowed to flow. If, because of the nature of the operation performed or due to the position of the packer, the pressure below a packer is greater than the pressure above the packer, pressure in the wellbore above the packer may be increased by displacing a higher or
lower density fluid into the wellbore above the packer or by pressurizing the area above the packer. Once the pressure is equalized, the work string can then be manipulated to unset the packer.

[0007] There are a number of difficulties associated with the present methods of isolating formations utilizing packers lowered into a wellbore on coiled tubing. One manner of isolating sections is to utilize opposing cup packers which are well known in the art. To isolate a particular section of a wellbore, such a system utilizes upper and lower cup packers that are energized simply by flowing through a port between the packers which causes expansion of the packers by creating a differential pressure at the cups. Pressure may be equalized before attempting to move the packer by flowing the well back up the tubing. There are some difficulties associated with such a method, including leak-off and compression, and safety concerns because of the gasified fluids communicated to the surface. It is also sometimes necessary to reverse-circulate fluids to reduce the differential pressure used to set the cup packers. There are environments, however, where it is difficult to reverse-circulate. Although some opposing cup tools have a bypass which will allow the pressure above and below the tools to equalize, the bypasses cannot handle environments wherein fluids have a high solids content.

[0008] Although such a system may work adequately, compression packers are more reliable and create less wear on the coiled tubing. Compression packers utilized on coiled tubing to isolate a section of a wellbore typically have a solid bottom such that communication with the wellbore through the lower end of the packer is not possible and the only way to equalize pressure and unset the packer is by flowing the well or by pressurizing the wellbore. This presents many of the same problems associated with a dual cup packer system. If the tools are moved when differential pressure exists, damage may occur and such operations can be time-consuming and costly.

**SUMMARY OF THE INVENTION**

[0009] The present invention relates to systems and methods useful in subterranean treatment operations. More particularly, the present invention relates to systems and methods for treating subterranean formations using low-molecular weight treatment fluids.

[0010] An example of a method of the present invention is a method of treating a subterranean formation intersected by a wellbore comprising: lowering a work string having a first packer apparatus connected to a lower end of the work string to a desired location in the wellbore, the work string being communicated with the wellbore through a longitudinal opening defined by the first packer apparatus, the first packer apparatus comprising: a packer mandrel; and an expandable packer element disposed about the packer mandrel; compressing the expandable packer element by lowering the packer mandrel relative to the expandable packer element thereby expanding the packer element outward to engage and seal a casing in the wellbore below the formation, wherein the compressing step seals the longitudinal opening to prevent communication therethrough; displacing a low-molecular-weight fluid down the work string and into the wellbore through a flow port defined in the work string above the first packer apparatus, so as to create or enhance at least one fracture in the subterranean formation; unsealing the longitudinal opening after the displacing step to communicate a portion of the wellbore above the expandable packer element with a portion of the wellbore below the expandable packer element through the longitudinal opening to equalize a pressure in the wellbore above and below the expandable packer element; and disengaging the expandable packer element from the casing.

[0011] Another example of a method of the present invention is a method of reducing the cost of enhancing production from multiple formations penetrated by a well bore by stimulating multiple formations, on a single trip through the well bore, with a fluid that minimizes damage to the formation comprising: lowering a work string having a first packer apparatus connected to a lower end of the work string to a desired location in the wellbore, the work string being communicated with the wellbore through a longitudinal opening defined by the first packer apparatus, the first packer apparatus comprising: a packer mandrel; and an expandable packer element disposed about the packer mandrel; compressing the expandable packer element by lowering the packer mandrel relative to the expandable packer element thereby expanding the packer element outward to engage and seal a casing in the wellbore below the formation, wherein the compressing step seals the longitudinal opening to prevent communication therethrough; displacing a low-molecular-weight fluid down the work string and into the wellbore above the expandable packer element through the longitudinal opening to equalize a pressure in the wellbore above and below the expandable packer element; and disengaging the expandable packer element from the casing; and moving the packer apparatus to another formation in the well bore and repeating the step of displacing a low-molecular-weight fluid down the work string and into the wellbore to create or extend at least one fracture in the formation.
molecular-weight fluid having the capability of enhancing the regain permeability of the formation; unsealing the longitudinal opening after the displacing step to communicate a portion of the wellbore above the expandable packer element with a portion of the wellbore below the expandable packer element through the longitudinal opening to equalize a pressure in the wellbore above and below the expandable packer element; determining, in real time, at least one parameter related to the creation or enhancement of the at least one fracture; disengaging the expandable packer element from the casing; and moving the packer apparatus to another formation adjacent the well and repeating the step of displacing a low-molecular-weight fluid down the work string and into the wellbore to create or extend at least one fracture in the formation.

Yet another method of the present invention is a method of enhancing production from multiple subterranean formations penetrated by a well bore during a single trip through the well bore, comprising: lowering a work string having a first packer apparatus connected to a lower end of the work string to a desired location in the wellbore, the work string being communicated with the wellbore through a longitudinal opening defined by the first packer apparatus, the first packer apparatus comprising: a packer mandrel; and an expandable packer element disposed about the packer mandrel; compressing the expandable packer element by lowering the packer mandrel relative to the expandable packer element thereby expanding the packer element outward to engage and seal a casing in the wellbore below the formation, wherein the compressing step seals the longitudinal opening to prevent communication therethrough, displacing a low-molecular-weight fluid down the work string and into the wellbore through a flow port defined in the work string above the first packer apparatus, so as to create or extend at least one fracture in the subterranean formation, the low-molecular-weight fluid having the capability of enhancing the regain permeability of the formation; unsealing the longitudinal opening after the displacing step to communicate a portion of the wellbore above the expandable packer element with a portion of the wellbore below the expandable packer element through the longitudinal opening to equalize a pressure in the wellbore above and below the expandable packer element; disengaging the expandable packer element from the casing; and moving the packer apparatus to another formation adjacent the well and repeating the step of displacing a low-molecular-weight fluid down the work string and into the wellbore to create or extend at least one fracture in the formation.

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

A more complete understanding of the present disclosure and advantages thereof may be acquired by referring to the following description taken in conjunction with the accompanying drawings, wherein:

FIG. 1 illustrates a packer apparatus of the present invention disposed in a wellbore;

FIG. 2 schematically shows the packer apparatus set in a wellbore.

FIGS. 3A-3D are partial section views of the packer apparatus of the present invention in the running position.

FIGS. 4A-4D are partial section views of the packer apparatus in the set position.

FIGS. 5A-5D are partial section views of the packer apparatus of the present invention in the retrieving position.

FIG. 6 shows a flat pattern of the J-slot defined in the packer mandrel of the present invention.

FIG. 7 shows an alternative embodiment of a drag sleeve of the present invention.

While the present invention is susceptible to various modifications and alternative forms, specific exemplary embodiments thereof have been shown in the drawings and are herein described. It should be understood, however, that the description herein of specific embodiments is not intended to limit the invention to the particular forms disclosed, but on the contrary, the intention is to cover all modifications, equivalents, and alternatives falling within the spirit and scope of the invention as defined by the appended claims.

DETAILED DESCRIPTION OF EXEMPLARY EMBODIMENTS

The present invention relates to systems and methods useful in subterranean treatment operations. More particularly, the present invention relates to systems and methods for treating subterranean formations using low-molecular-weight fluids. As referred to herein, the term "low-molecular-weight fluid" is defined to mean a fluid that has an average molecular weight of less than about 1,000. Certain embodiments of the low-molecular-weight fluids useful in accordance with the present invention may have a viscosity, measured at a reference temperature of about 25°C, of at least about 2 cP; such viscosity may be measured on, for example, a Fann Model 35 viscometer, or the like. Certain other embodiments of low-molecular-weight fluids useful with the present invention may have a lower viscosity, such as, for example, when the low-molecular-weight fluid is water.

In certain embodiments of the present invention, the use of a low-molecular-weight fluid in the methods and systems of the present invention may result in, among other things, improved cleanup of the low-molecular-weight fluid at the conclusion of the treatment operation, and reduced loss of the low-molecular-weight fluid into the subterranean formation during the treatment operation. The subterranean formation also may exhibit improved "regain permeability" upon the conclusion of the treatment operation. As referred to herein, the term "regain permeability" will be understood to mean the degree to which the permeability of a formation that has been exposed to a treatment fluid approaches the original permeability of the formation. For example, a determination that a subterranean formation evidences "100% regain permeability" at the conclusion of a treatment operation indicates that the permeability of the formation, post-operation, is equal to its permeability before the treatment operation. In certain embodiments of the present invention, the methods and systems of the present invention may permit, inter alia, highly accurate, "pinpoint" placement
of a fracture that has been created or enhanced through the injection of a low-molecular-weight fluid at a desired location in a reservoir.

[0026] In certain embodiments of the present invention, the low-molecular-weight fluid may comprise an acid system. The acid system may be polymer-based or nonpolymer-based. In certain embodiments, the acid system may comprise a viscosifier (sometimes referred to as a “gelling agent”). Where the acid system comprises a viscosifier, a broad variety of viscosifiers may be used, including, but not limited to, emulsifiers and surfactants. Examples of suitable viscosifiers include, but are not limited to, those that are commercially available from Halliburton Energy Services, Inc., under the trade names SGA-HT, SGA-A, and SGA-II. In certain embodiments wherein the low-molecular-weight fluid used in the methods and systems of the present invention is an acid system that comprises a viscosifier, the viscosifier may be present in the acid system in an amount in the range of from about 0.001% to about 0.035% by volume. Examples of other acid systems that may be suitable include, but are not limited to, a hydrochloric acid based delayed carbonate acid system that is commercially available from Halliburton Energy Services, Inc., under the trade name CARBONATE 20/20, and a hydrofluoric acid based delayed carbonate acid system that is commercially available from Halliburton Energy Services, Inc., under the trade name SANDSTONE 2000.

[0027] Another example of a suitable low-molecular-weight fluid that may be used with the methods and systems of the present invention is water. Generally, the water may be from any source.

[0028] Another example of a suitable low-molecular-weight fluid is described in U.S. Pat. No. 6,488,091, the relevant disclosure of which is hereby incorporated by reference. Such low-molecular-weight fluid has an average molecular weight in the range of from about 100,000 to about 250,000, generally has a viscosity (measured at a reference temperature of about 25° C. on, for example, a Fann Model 35 viscometer, or the like) of at least about 8 cP, and generally comprises water, a substantially fully hydrated depolymerized polymer, and a crosslinking agent for crosslinking the substantially fully hydrated depolymerized polymer. The water can be selected from fresh water, unsaturated salt water (e.g., brines and seawater), and saturated salt water. The substantially fully hydrated depolymerized polymer in the low-molecular-weight fluid may be, inter alia, a depolymerized polysaccharide. In certain embodiments, the substantially fully hydrated depolymerized polymer is a substantially fully hydrated depolymerized guar derivative polymer selected from the group consisting of hydroxypropyl guar, carboxymethylhydroxypropyl guar, carboxymethylguar, hydroxyethylguar and carboxymethylhydroxyethylguar. In certain embodiments, the substantially fully hydrated depolymerized polymer is substantially fully hydrated depolymerized hydroxypropyl guar. Generally, where the low-molecular-weight fluid comprises water, a substantially fully hydrated depolymerized polymer, and a crosslinking agent, the substantially fully hydrated depolymerized polymer is present in the low-molecular-weight fluid in an amount in the range of from about 0.2% to about 5% by weight of the water therein.

[0029] Optionally, the low-molecular-weight fluids suitable for use with the present invention may further comprise a crosslinking agent. A broad variety of crosslinking agents may be suitable for use in accordance with the methods and systems of the present invention. For example, where the low-molecular-weight fluids useful in the present invention comprise water, and a substantially fully hydrated depolymerized polymer, suitable crosslinking agents include, but are not limited to, boron-based compounds (e.g., boric acid, ulexite, colemanite, disodium octoborate tetrahydrate, sodium diborate and pentaborates). The crosslinking of the substantially fully hydrated depolymerized polymer that may be achieved by these crosslinking agents generally is fully reversible (e.g., the crosslinked, substantially fully hydrated polymer easily may be delinked if and when desired). Metal-based crosslinking agents also may be suitable, bearing in mind that crosslinking of the substantially fully hydrated depolymerized polymer that may be achieved by these crosslinking agents generally is less reversible. Examples of suitable metal-based crosslinking agents include, but are not limited to, compounds that can supply zirconium IV ions (e.g., zirconium lactate, zirconium lactate triethanolamine, zirconium carbonate, zirconium acetylacetonate and zirconium diisopropylamine lactate), compounds that can supply titanium IV ions (e.g., titanium ammonium lactate, titanium triethanolamine, and titanium acetylacetonate), aluminum compounds (e.g., aluminum lactate or aluminum citrate), or compounds that can supply antimony ions. In certain embodiments, the crosslinking agent is a borate compound. The exact type and amount of crosslinking agent, or agents, used depends upon, inter alia, the specific substantially fully hydrated depolymerized polymer to be crosslinked, formation temperature conditions and other factors known to those individuals skilled in the art. Where included, the optional crosslinking agent may be present in the low-molecular-weight fluid in an amount in the range of from about 50 ppm to about 5000 ppm active crosslinker.

[0030] Optionally, when the low-molecular-weight fluids useful with this invention are used to carry out a fracture stimulation procedure, proppant material may be included in at least a portion of the low-molecular-weight fluid as it is pumped into the subterranean formation to be fractured and into fractures created therein. For example, the proppant material may be metered into the low-molecular-weight fluid as the low-molecular-weight fluid is formed. The quantity of proppant material per volume of low-molecular-weight fluid can be changed, as desired, in real time. Examples of proppant material that may be utilized include, but are not limited to, resin-coated or uncoated sand, sintered bauxite, ceramic materials or glass beads. Suitable materials are commercially available from Carboceramics, Inc., of Irving, Tex.; Sintex Minerals & Services, Inc., of Houston, Tex.; and Norton-Alcoa Proppants, of Fort Smith, Ark. Examples of intermediate strength ceramic proppants that may be suitable include, but are not limited to, Econo-Prop®, Carbo Lite®, Carbo Prop®, Intreprop®, Naplite®, and Valuprop®. Examples of high strength ceramic proppants include, but are not limited to, Carbo HSP®, Sintered Bauxite and SinterBall®. Where included, the proppant material utilized may be present in the low-molecular-weight fluid in an amount in the range of from about 0.25 to about 24 pounds of proppant material per gallon of the low-molecular-weight fluid.

[0031] Optionally, in certain embodiments wherein the low-molecular-weight fluid comprises water, a crosslinking
agent, and a substantially fully hydrated depolymerized polymer, a pH-adjusting compound for adjusting the pH of the low-molecular-weight fluid to the optimum pH for crosslinking may be included in the low-molecular-weight treating fluid. The pH-adjusting compound can be selected from sodium hydroxide, potassium hydroxide, lithium hydroxide, fumaric acid, formic acid, acetic acid, hydrochloric acid, acetic anhydride and the like. In certain embodiments, the pH-adjusting compound is sodium hydroxide. Where included, the pH-adjusting compound may be present in the low-molecular-weight fluid in an amount in the range of from about 0.01% to about 0.3% by weight of the water in the low-molecular-weight fluid. In certain embodiments wherein the pH-adjusting compound comprises a borate compound, the pH-adjusting compound is utilized to elevate the pH of the low-molecular-weight fluid to above about 9. At that pH, the borate compound crosslinking agent crosslinks the short chain hydrated polymer segments. When the pH of the crosslinked low-molecular-weight fluid falls below about 9, the crosslinked sites are no longer crosslinked. Thus, when the crosslinked low-molecular-weight fluid contacts the subterranean formation being treated, the pH may be lowered to some degree, which may begin the breaking process.

Optionally, in certain embodiments wherein the low-molecular-weight fluid comprises water, a crosslinking agent, and a substantially fully hydrated depolymerized polymer, the low-molecular-weight fluid may comprise a delayed delinker capable of lowering the pH of the low-molecular-weight fluid. In certain embodiments, the presence of the delayed delinker in the low-molecular-weight fluid may cause the low-molecular-weight fluid to completely revert to a thin fluid in a short period of time. Examples of delayed delinkers that may be utilized include, but are not limited to, various lactones, esters, encapsulated acids and slowly-soluble acid-generating compounds, oxidizers which produce acids upon reaction with water, water-reactive metals such as aluminum, lithium and magnesium and the like. In certain embodiments, the delayed delinker comprises an ester. Where included, the delayed delinker may be present in the low-molecular-weight fluid in an amount in the range of from about 0.01% to about 1% by weight of the water therein. Alternatively, any of the conventionally used delayed breakers employed with metal ion crosslinkers can be utilized, for example, oxidizers such as sodium chlorite, sodium bromate, sodium persulfate, ammonium persulfate, encapsulated sodium persulfate, potassium persulfate, or ammonium persulfate, and the like, as well as magnesium peroxide, and encapsulated acids. Enzyme breakers that may be employed include alpha and beta amylases, amyloglucosidase, invertase, maltase, cellulase and hemicellulase. The specific breaker or delinker utilized, whether or not it is encapsulated, as well as the amount thereof employed will depend upon factors including, inter alia, the breaking time desired, the nature of the polymer and crosslinking agent, and formation characteristics and conditions.

Optionally, the low-molecular-weight fluid also may include a surfactant. The inclusion of a surfactant in the low-molecular-weight fluid may, inter alia, prevent the formation of emulsions between the low-molecular-weight fluid and subterranean formation fluids contacted by the low-molecular-weight fluid. Examples of such surfactants include, but are not limited to, alkyl sulfonates, alkyl aryl sulfonates (e.g., alkyl benzyl sulfonates such as salts of dodecylbenzene sulfonic acid), alkyl trimethylammonium chloride, branched alkyl ethoxylated alcohols, phenol-formaldehyde nionic resin blends, cocobetaines, dioctyl sodium sulfosuccinate, imidazolines, alpha olefin sulfonates, linear alkyl ethoxylated alcohols, trialkyl benzylammonium chloride and the like. In certain embodiments, the surfactant may comprise methanol. An example of a suitable surfactant is commercially available from Halliburton Energy Services, Inc., under the trade name “LO-SURF 300.” In certain embodiments, the surfactant comprises dodecylbenzene sulfonic acid salts. Where included, the surfactant generally is present in the low-molecular-weight fluid in an amount in the range of from about 0.001% to about 0.5% by weight of the water therein.

Optionally, the low-molecular-weight fluid also may include a clay stabilizer selected, for example, from the group consisting of potassium chloride, sodium chloride, ammonium chloride, tetramethyl ammonium chloride, and the like. An example of a suitable clay stabilizer is commercially available from Halliburton Energy Services, Inc., under the trade name “CLA-STA XP.” In certain embodiments, the clay stabilizer is potassium chloride or tetramethyl ammonium chloride. Where included, the clay stabilizer is generally present in the low-molecular-weight fluid in an amount in the range of from about 0.001% to about 1% by weight of the water therein.

Optionally, the low-molecular-weight fluid may comprise a fluid loss control agent. Examples of fluid loss control agents that may be used include, but are not limited to, silica flour, starches, waxes, diesels, and resins. An example of a suitable silica flour is commercially available from Halliburton Energy Services, Inc., under the trade name “WAC-9.” An example of a suitable starch is commercially available from Halliburton Energy Services, Inc., under the trade name “ADOMITE AQUA.” Where included, the fluid loss control agent may be present in the low-molecular-weight fluid in an amount in the range of from about 0.01% to about 1% by weight of the water therein.

Optionally, the low-molecular-weight fluid also may include compounds for retarding the movement of the propellant within the created or enhanced fracture. For example, materials in the form of fibers, flakes, ribbons, beads, shavings, platelets and the like that comprise glass, ceramics, carbon composite, natural or synthetic polymers, resins, or metals and the like can be admixed with the low-molecular-weight fluid and propellant. A more detailed description of such materials is disclosed in, for example, U.S. Pat. Nos. 5,330,005; 5,439,055; and 5,501,275, the relevant disclosures of which are incorporated herein by reference. Examples of suitable epoxy resins include those that are commercially available from Halliburton Energy Services, Inc., under the trade names “EXPEDIT” and “SAND WEDGE.” Alternatively, or in addition to the prior materials, a material comprising a tackifying compound may be admixed with the low-molecular-weight fluid or the propellant particulates to coat at least a portion of the propellant particulates, or other solid materials identified above, such that the coated material and particulate adjacent thereto will adhere together to form agglomerates that may bridge in the created fracture to prevent particulate flowback. The tackifying compound also may be introduced into the formation with the low-molecular-weight fluid before or after
the introduction of the proppant into the formation. The coated material is effective in inhibiting the flowback of fine particulate in the proppant pack having a size ranging from about that of the proppant to less than about 600 mesh. The coated proppant or other material is effective in consolidating fine particulates in the formation in the form of agglomerates to prevent the movement of the fines during production of the formation fluids from the well bore subsequent to the treatment. A more detailed description of the use of such tackifying compounds and methods of use thereof are disclosed in U.S. Pat. Nos. 5,775,415; 5,787,986; 5,833,000; 5,839,510; 5,871,049; 5,853,048; and 6,047,772, the relevant disclosures of which are incorporated herein by reference thereto.

[0037] Optionally, additional additives may be included in the low-molecular-weight fluids including, but not limited to, scale inhibitors, demulsifiers, bactericides, breakers, activators and the like. An example of a suitable scale inhibitor is commercially available from Halliburton Energy Services, Inc., under the trade name “SCA 110.” An example of a suitable breaker is commercially available from Halliburton Energy Services, Inc., under the trade name “VICON.” Another example of a suitable breaker is commercially available from Halliburton Energy Services, Inc., under the trade name “HMP DE-LINK.” Examples of suitable bactericides are commercially available from Halliburton Energy Services, Inc., under the trade names “BE-3” and “BE-6.”

[0038] In one embodiment, the present invention provides a system that advantageously may be used with a low-molecular-weight fluid to perform a variety of functions in a subterranean formation. Referring now to FIGS. 1 and 2, a packer designated by the numeral 10 is shown connected in a work string 15 disposed in a well bore 20. A casing 25 may be cemented in well bore 20. Work string 15 and casing 25 define an annulus 30. As illustrated in FIGS. 1 and 2, well bore 20 intersects a formation 35. Formation 35 typically comprises hydrocarbons. Casing 25 has perforations 40 adjacent formation 35, such that formation 35 is in fluid communication with annulus 30.

[0039] In addition to packer 10, work string 15 also may include: a ported sub 42 connected to an upper end of packer 10; blast joints 44 connected to ported sub 42; a centralizer 46; and an upper packer 48 connected to centralizer 46. Upper packer 48 may have a shear release joint 50 connected to the upper end thereof. Upper packer 48 may have a second centralizer 52 connected thereto. Centralizer 52 has a coiled tubing connector 54 connected thereto, which is adapted to be connected to coiled tubing 56. FIGS. 1 and 2 illustrate packer 10 during its placement within well bore 30 as part of work string 15. Work string 15 is positioned so that packer 10 is positioned below formation 35. Packer 48, which may be a cup packer of the type known in the art, is positioned above formation 35. FIG. 1 schematically illustrates packer 10 in a running or unset position 58, while FIG. 2 schematically illustrates packer 10 in its set position 60. Packer 10 also is shown in the running position 58 in FIGS. 3A through 3D, and in the set position 60 in FIGS. 4A through 4D. In FIGS. 5A through 5D, packer 10 is shown in a retrieving position 62. In each of FIGS. 3, 4, and 5, casing 25 is depicted by a dashed line.

[0040] Packer 10 comprises a housing 70 having an upper end 72 and a lower end 74. Housing 70 defines a longitudinal opening 76 extending from upper end 72 to lower end 74 thereof. Housing 70 is connected at threaded connection 78 to a lower end 80 of ported sub 42. Ported sub 42 has an upper end 82 having threads 84 defined therein, and thus is adapted to be connected in work string 15 between lower or first packer 10 and upper or second packer 48. Ported sub 42 defines an interior or longitudinal flow passage 86. Ported sub 42 also defines at least one port 88 (and, in certain embodiments, a plurality of ports 88) defined therethrough intersecting flow passage 86 and thus communicating flow passage 86 with well bore 20, and particularly with annulus 30.

[0041] Packer 10 further includes a packer element 90, which in certain embodiments is an elastomeric packer element disposed about housing 70. Housing 70 comprises a packer mandrel 92 having a drag sleeve 94 disposed thereabout. Packer element 90 is disposed about packer mandrel 92 above drag sleeve 94. Packer mandrel 92 has an upper end 96, a lower end 98 and defines a longitudinal opening 100 extending therebetween. Longitudinal opening 100 defines a portion of longitudinal opening 76. Threads 102 are defined in packer mandrel 92 at upper end 96 on an inner surface 104 thereof. Packer mandrel 92 further defines an outer surface 105.

[0042] Inner surface 104 of packer mandrel 92 defines a first inner diameter 106, a second inner diameter 108 therebelow and extending radially inwardly therefrom, and a third inner diameter 110 extending radially inwardly from second diameter 108. An upward facing shoulder 112 is defined by, and extends between, second and third inner diameters 108 and 110, respectively. Inner surface 104 further defines a tapered surface 114 extending downwardly and radially outwardly from third inner diameter 110 to a fourth inner diameter 116. A fifth inner diameter 118 has a magnitude greater than that of fourth inner diameter 116 and extends downwardly from a lower end 120 of fourth inner diameter 116 to lower end 98 of packer mandrel 92.

[0043] A seal 122 having an upper end 124 and a lower end 126 is disposed in packer mandrel 92 and, in certain embodiments, is received in second inner diameter 108. In certain embodiments, seal 122 includes an elastomeric seal element 128, and may have seal spacers 129 disposed in packer mandrel 92 to engage the upper and lower ends of seal element 128. Seal 122 has an inner surface 130 defining an inner diameter 132 that, in certain embodiments, is substantially identical to, or slightly smaller than, third inner diameter 110. Third inner diameter 110 and diameter 132 defined by seal 122 may be referred to as a reduced diameter portion 133 of packer mandrel 92 which, as explained in greater detail below, will be sealingly engaged by the equalizing valve disposed in housing 70. A seal retainer 134 having an upper end 136 and a lower end 138 is threadedly connected to packer mandrel 92 at threads 102. Seal 122 is held in place by lower end 138 of seal retainer 134 and shoulder 112.

[0044] Outer surface 105 defines a first outer diameter 140 and a second outer diameter 142. A tapered shoulder 144 is defined on, and extends radially outwardly from, first outer diameter 140 above second outer diameter 142. Second outer diameter 142 extends radially outwardly from, and has a greater diameter than, first outer diameter 140.

[0045] Packer element 90 is disposed about outer surface 105. In certain embodiments, packer element 90 is disposed
about first outer diameter 140 of outer surface 105. Packer element 90 has an upper end 144, a lower end 146, an inner surface 148, and an outer surface 150. A packer shoe 152 having an upper end 154 and a lower end 156 is disposed about packer mandrel 92. Packer shoe 152 is connected to packer mandrel 92 with a screw 153 (not shown in FIGS. 4A-4D and 5A-5D) and shear pin 155 (not shown in FIGS. 4A-4D and 5A-5D), or by other means known in the art.

Lower end 156 of packer shoe 152 engages upper end 146 of packer element 90.

[0046] A wedge 158 having an upper end 160 and a lower end 162 is disposed about outer surface 150 of packer mandrel 92. Upper end 160 of wedge 158 engages lower end 146 of packer element 90. Wedge 158 has an outer surface 163 that defines an outer diameter 164 that extends from the upper end 160 thereof a portion of the distance to lower end 162, and has a lower end 166. Outer surface 163 of wedge 158 tapers radially inwardly from lower end 166 of outer diameter 164 to lower end 162 of wedge 158 and comprises a tapered surface 165. When packer 10 is in running position 58, lower end 162 of wedge 158 engages radially outwardly extending shoulder 141 on outer diameter 140 of packer mandrel 92.

[0047] Packer mandrel 92 defines a continuous J-slot 170 in the second outer diameter 142 thereof. J-slot 170 is illustrated in a flat pattern in FIG. 6, and will be described in greater detail hereinbelow. Drag sleeve 94 is disposed about packer mandrel 92, and along with packer mandrel 92 comprises housing 70. Drag sleeve 94 has an outer surface 173, an inner surface 175, an upper end 174 and a lower end 176 that extends downwardly beyond lower end 98 of packer mandrel 92, and comprises lower end 72 of housing 70. A slip 178 is disposed about packer mandrel 92 above drag sleeve 94. Slip 178 has an upper end 180 and a lower end 182. Lower end 182 engages upper end 174 of drag sleeve 172. An inner surface 184 of slip 178 has an upper portion 186 and a lower portion 188. Upper portion 186 of inner surface 184 is a tapered surface 190 that extends radially outwardly from packer mandrel 92 and is adapted to engage tapered surface 165 on wedge 158. Slip 178 is of a type well known in the art, and has teeth 192 adapted to engage casing 25. Leaf springs 194 extend upwardly from upper end 174 of drag sleeve 94, and are adapted to engage slip 178 and to prevent slip 178 from prematurely engaging the casing. A plurality of drag springs 196 are attached to drag sleeve 172. Drag springs 196 extend radially outwardly from outer surface 173, and will engage casing 25 when packer 10 is in its running and retrieving positions 58 and 62, respectively. At least one (and, in certain embodiments, two) lugs 198 are threadedly connected to drag sleeve 94, and extend radially inwardly from inner surface 175. Lug 198 extends into, and is retained in, J-slot 170 defined in packer mandrel 92.

[0048] Inner surface 175 of drag sleeve 94 has threads 200 defined thereon at the lower end 176 thereof. An equalizing valve 210 is threadedly connected to drag sleeve 172 at threads 200, and extends upwardly therefrom into packer mandrel 92. Equalizing valve 210 has a lower end 212 and extends upwardly in housing 70 to an upper end 214. Equalizing valve 210 is generally tubular, and has a tapered upper end 214. Upper end 214 is a ported upper end, and thus includes a generally vertical opening 216 extending downwardly from tip 215 thereof. At least one radial port 219 (and, in certain embodiments, a plurality of radial ports 219) extend radially outwardly from the lower end 218 of vertical opening 216 through the side of equalizing valve 210.

[0049] Equalizing valve 210 may be assembled in sections that include ported valve tip 220, which is threaded connected to a valve extension 222 having upper and lower ends 224 and 226, respectively. A valve bypass insert 228 is threadedly connected to valve extension 222. Valve bypass insert 228 is threadedly connected to threads 200 on drag sleeve 94. Valve bypass insert 228 has a plurality of passageways 229 therethrough, to provide for the communication of fluid therethrough.

[0050] Optionally, an operator may elect to employ a pressure sensor (not shown) as part of work string 15. A wide variety of pressure sensors may be used in accordance with the present invention. In certain embodiments, the pressure sensor may be capable of storing data that may be generated during a subterranean operation until a desired time, e.g., until the completion of the operation when the pressure sensor is removed from the subterranean function. In certain embodiments of the present invention, the incorporation of a pressure sensor may permit an operator to evaluate conditions in the subterranean formation (which conditions may include, but are not limited to, parameters related to the creation or enhancement of the fracture) in real time or near-real-time, and, inter alia, to undertake a remediative step in real time or near-real-time. Example of remediative steps include, inter alia, swapping from a propellant-laden fluid to a linear fluid, reducing the concentration of a propellant present in the fluid, and reducing the viscosity of the fluid. In certain embodiments of the present invention, the operator may be able to determine, in real-time, that the fracture in the subterranean formation has been created or enhanced to a desired extent. In certain embodiments, the operator may move packer 10 to a different zone in the same, or different, formation after determining, in real time, that the fracture has been created or enhanced to a desired extent. As referred to herein, the term “real time” will be understood to mean a time frame in which the occurrence of an event and the reporting or analysis of it are almost simultaneous; e.g., within a maximum duration of not more than two periods of a particular signal (e.g., a pressure signal, electrical signal, or the like) being evaluated. For example, an operator may view, in real time, a plot of the pressure in the formation that has been transmitted by the optional pressure sensor (not shown), and determine, at a particular time during the fracturing operation, that an increase, or increases, in the slope of the pressure indicate the need to perform a remediative step such as those described above.

One of ordinary skill in the art, with the benefit of this disclosure, will be able to evaluate a real time plot of the pressure in the formation, and evaluate conditions in the formation, and determine the appropriate remediative step to perform in response.

[0051] Optionally, an operator may elect to employ a tension indicator (not shown) as part of work string 15. The inclusion of a tension indicator may provide an operator with a broad-variety of information. In certain embodiments of the present invention, the inclusion of a tension indicator may enable an operator to identify, inter alia, whether packer 10 has been completely set, or completely unset. In certain embodiments of the present invention, the inclusion of a
tension indicator may enable an operator to identify, inter alia, the location within a well where an obstruction may be hindering the ability to move packer 10; in certain embodiments of the present invention, these identifications, and the determination of other similar parameters, may be made in real time. For example, an operator may view a real time plot of the tension sensed by the tension indicator, and determine, upon detection of an increase or decrease in the tension, that the packer has become unset, or, as another example, that the tension sensed by the tension indicator has increased sufficiently to suggest that the mechanical integrity of packer 10, or another element of work string 15, may be imperilled. In certain embodiments, the operator may undertake a remediative step after making such real time determination or identification. An example of a remediative step includes, but is not limited to, raising or lowering work string 15 without unsetting packer 10. Another example of a remediative step includes, but is not limited to, increasing or decreasing the flow rate of the low-molecular-weight fluid. One of ordinary skill in the art, with the benefit of this disclosure, will be able to evaluate a real time plot of the tension and determine the appropriate remediative step to perform in response.

[0052] In certain embodiments of the present invention, packer 10 operates in the following manner. Packer 10 is lowered into well bore 20 (as schematically depicted in FIG. 1) on work string 15. Drilling fluid or other fluid in the well bore 20 may be communicated through valve bypass insert 228 into the housing and upward into ported sub 42. Fluid in the well bore 20 also is communicated through ports 88 in ported sub 42.

[0053] Running position 58 also may be referred to as an “open” position of packer 10, as it permits communication of fluid through housing 70. Thus, when packer 10 is in running position 58, equalizing valve 210 also may be said to be in an “open” position, which may be referred to as a first open position 230. Packer 10 also is lowered into the well bore 20 until it reaches a desired location in the well bore 20, as shown in FIG. 1. As illustrated therein, packer 10 is located below formation 35, in which an operation is to be performed, and upper packer 48 is located above formation 35. The operation to be performed may be a production operation, treatment operation (e.g., fracturing), or another desired operation.

[0054] As packer 10 is lowered into the well bore 20, J-slot 170 will engage lug 198 such that drag sleeve 94 moves downward with packer mandrel 92. As illustrated in FIG. 6, J-slot 170 has two packer set legs 232A and 232B, respectively, two packer run legs 234A and 234B, respectively, and four packer retrieve legs 236A, 236B, 236C, and 236D, respectively.

[0055] J-slot 170 also includes upper ramps 233 extending between the packer set legs 232A-232B and the packer run legs 234A-234B, and has lower ramps 235 extending between adjacent packer retrieve legs 236A-236D. When packer 10 is being lowered into the well bore 20, lug 198 will engage one of packer run legs 234A-234B. In FIG. 6, lug 198 is shown engaging an upper end of packer set leg 234A. When packer 10 has reached its desired location in the well bore, the work string may be lifted upwardly, to move packer 10 from its running position 58 to its set position 60. Upward pull on coiled tubing 56 will cause packer mandrel 92 to move upward relative to drag sleeve 94, which will be held in place by the engagement of drag springs 196 with casing 25. Lug 198 will engage a lower ramp 235, which will cause rotation of drag sleeve 94 relative to packer mandrel 92. The upward pull is continued, until lug 198 is positioned over a retrieving leg 236A-236D, and in FIG. 6, over leg 236B. Coiled tubing 56 then may be released and allowed to move downwardly, so that packer mandrel 92 moves downwardly relative to drag sleeve 94 and thus downward relative to equalizing valve 210. Slip 178 is urged radially outwardly by wedge 158 to engage casing 25. When slip 178 engages casing 25, downward movement of wedge 158 stops. Packer shoe 152 will continue to move with packer mandrel 92 and will compress packer element 90 so that it sealingly engages casing 25. Lug 198 will engage an upper ramp 233, and as packer mandrel 92 continues to be lowered, drag sleeve 94 will rotate and lug 198 will be received in a packer set leg 232A-232B, in this case leg 232A until it reaches the set position 60. When packer 10 is moved to its set position 60, which may also be referred to as a “closed” position of the packer 10, equalizing valve 210 moves upward relative to packer mandrel 92 to a closed position 240, such that it engages reduced diameter portion 135 and is sealingly engaged by seal 122. Equalizing valve 210 thus moves to closed position 240 when packer 10 is actuated to its set position 60, wherein packer element 90 sealingly engages casing 25 below formation 35.

[0056] When the equalizing valve 210 is in closed position 240, it seals longitudinal opening 76 such that communication through housing 70 is blocked. Thus, fluid may be displaced down coiled tubing 56 and through ports 88 to treat formation 35, or the formation 35 may be produced through ports 88. For example, if the formation 35 is to be fractured, a low-molecular-weight fluid may be displaced down coiled tubing 56 and out ports 88 into annulus 30 and formation 35. Displacement of fluid into annulus 30 through ports 88 will energize upper packer 48 so that it seals against casing 25 above formation 35. Pressure above packer element 90 will increase as the low-molecular-weight fluid is continually displaced through ports 88 into the annulus 30 between packer element 90 and upper packer 48.

[0057] Once the desired operation, in this case fracturing, is complete, it may be desirable to either remove work string 15 from wellbore 20, or to move the work string 15 within the wellbore 20 to perform another operation at a different location within the wellbore 20. In order to do so, the pressure above and below the packer element 90 is equalized.

[0058] To equalize the pressure, upward pull is once again applied to packer mandrel 92 by pulling upwardly on coiled tubing 56. Packer mandrel 92 will move relative to equalizing valve 210 until radial ports 219 are below seal 122. This will allow fluid in wellbore 20 between packers 10 and 48 to pass through ports 88 into longitudinal opening 76 defined by housing 70, and out through valve bypass insert 228 into the wellbore 20 below packer element 90. As pressure begins to equalize, upward pull on coiled tubing 56 will become easier, and a greater flow area will be established when equalizing valve 210 is completely removed from reduced diameter portion 133, such that free communication is allowed from wellbore 20 into ports 88 and downward through housing 70. Because free communication is allowed, pressure will equalize and the packer 10 can
be easily unset simply by continuing to pull upwardly on packer mandrel 92 with coiled tubing 56. Because there will be little or no differential pressure across packer element 90, upward pull will allow the packer 10 to unset. The packer 10 can be pulled upwardly and retrieved, as depicted in FIGS. 5A-5D or if desired can be moved to another location in the wellbore 20 and can be reset so that treatment and/or production from another formation can occur. This process can be repeated as often as possible in individual formations in the wellbore 20.

[0059] In the embodiment shown, lugs 198 are fixed to drag sleeve 94. Thus, drag sleeve 94 will rotate when packer mandrel 92 is moved vertically such that ramp 233 or 235, respectively, is engaged by lugs 198. An alternate lug arrangement is shown in FIG. 7.

[0060] FIG. 7 shows a drag sleeve 250. Drag sleeve 250 is identical in all aspects to drag sleeve 94 except that drag sleeve 250 is comprised of two pieces and includes a rotatable ring with lugs attached thereto as will be described. Drag sleeve 250, like drag sleeve 94, has drag springs 196 and has ports 231, along with the other features of drag sleeve 94. Drag sleeve 250 comprises an upper portion 252 having a lower end 254, and a lower portion 256 having an upper end 258. Drag sleeve 250 has an inner surface 260 which defines an inner diameter 262 on upper portion 252 and an inner diameter 264 on lower portion 256. Drag sleeve 250 has a recess 266 defined therein defining a recessed diameter 268, which is recessed outwardly from inner diameter 262. Recess 266 defines a downward facing shoulder 270 in upper portion 252.

[0061] A lug rotator assembly 272 is disposed in drag sleeve 250 in recess 266 and is rotatable therein. The lug rotator assembly 272 comprises a rotator ring 274 having an outer diameter 276 and an inner diameter 278. In certain embodiments, outer diameter 276 may be slightly smaller than recessed diameter 268, so that rotator ring 274 will rotate in recess 266. In certain embodiments, inner diameter 278 may be substantially the same as inner diameter 262. Lug rotator assembly 272 includes a pair of lugs 280 extending radially inwardly from inner diameter 278. Lugs 280 are adapted to be received in J-slot 170. Lugs 280 may have a generally cylindrical shaft portion 282 and a head 284. Head 284 defines a shoulder 286 and will engage an opposite facing shoulder 288 defined in rotator ring 274 in openings 290 in which lugs 280 are received. Lug rotator assembly 272 is held in place by downward facing shoulder 270 and upper end 258 of lower portion 256 of drag sleeve 250. Lug rotator assembly 272 will rotate relative to drag sleeve 250 when packer mandrel 92 is moved therein such that lugs 280 engage either the upper ramp 233 or the lower ramp 235 defined by the J-slot 170. Vertical movement of the packer mandrel 92, after lugs 280 have engaged a ramp, will cause lug rotator assembly 272 to rotate until the lugs 280 are positioned in a packer run leg, a packer set leg, or a packer retrieve leg depending on the operation to be performed. This ensures an apparatus that can be moved between its set and unset positions, even in wellbores where drag sleeves tightly engage the casing such that the drag sleeve will not readily rotate to allow lugs fixed thereto to be moved within the J-slot to a desired position.

[0062] Accordingly, an example of a method of the present invention is a method of treating a subterranean formation intersected by a wellbore comprising: lowering a work string having a first packer apparatus connected to a lower end of the work string to a desired location in the wellbore, the work string being communicated with the wellbore through a longitudinal opening defined by the first packer apparatus, the first packer apparatus comprising: a packer mandrel; and an expandable packer element disposed about the packer mandrel; compressing the expandable packer element by lowering the packer mandrel relative to the expandable packer element thereby expanding the packer element outward to engage and seal a casing in the wellbore below the formation, wherein the compressing step seals the longitudinal opening to prevent communication therethrough; displacing a low-molecular-weight fluid down the work string and into the wellbore through a flow port defined in the work string above the first packer apparatus, so as to create or enhance at least one fracture in the subterranean formation; unsealing the longitudinal opening after the displacing step to communicate a portion of the wellbore above the expandable packer element with a portion of the wellbore below the expandable packer element through the longitudinal opening to equalize a pressure in the wellbore above and below the expandable packer element; and disengaging the expandable packer element from the casing.

[0063] Another example of a method of the present invention is a method of reducing the cost of enhancing production from multiple formations penetrated by a well bore by stimulating multiple formations, on a single trip through the well bore, with a fluid that minimizes damage to the formation comprising: lowering a work string having a first packer apparatus connected to a lower end of the work string to a desired location in the wellbore, the work string being communicated with the wellbore through a longitudinal opening defined by the first packer apparatus, the first packer apparatus comprising: a packer mandrel; and an expandable packer element disposed about the packer mandrel; compressing the expandable packer element by lowering the packer mandrel relative to the expandable packer element thereby expanding the packer element outward to engage and seal a casing in the wellbore below the formation, wherein the compressing step seals the longitudinal opening to prevent communication therethrough; displacing a low-molecular-weight fluid down the work string and into the wellbore through a flow port defined in the work string above the first packer apparatus, so as to create or enhance at least one fracture in the subterranean formation, the low-molecular-weight fluid having the capability of enhancing the regain permeability of the formation; unsealing the longitudinal opening after the displacing step to communicate a portion of the wellbore above the expandable packer element with a portion of the wellbore below the expandable packer element through the longitudinal opening to equalize a pressure in the wellbore above and below the expandable packer element; disengaging the expandable packer element from the casing; and moving the packer apparatus to another formation in the well bore and repeating the step of displacing a low-molecular-weight fluid down the work string and into the wellbore to create or extend at least one fracture in the formation.

[0064] Another example of a method of the present invention is a method of enhancing production, in real time, from multiple subterranean formations penetrated by a well bore during a single trip through the well bore, comprising: lowering a work string having a first packer apparatus
connected to a lower end of the work string to a desired location in the wellbore, the work string being communicated with the wellbore through a longitudinal opening defined by the first packer apparatus, the first packer apparatus comprising: a packer mandrel; and an expandable packer element disposed about the packer mandrel; compressing the expandable packer element by lowering the packer mandrel relative to the expandable packer element thereby expanding the packer element outward to engage and seal a casing in the wellbore below the formation, wherein the compressing step seals the longitudinal opening to prevent communication therethrough; displacing a low-molecular-weight fluid down the work string and into the wellbore through a flow port defined in the work string above the first packer apparatus, so as to create or extend at least one fracture in the subterranean formation, the low-molecular-weight fluid having the capability of enhancing the regain permeability of the formation; unsealing the longitudinal opening after the displacing step to communicate a portion of the wellbore above the expandable packer element with a portion of the wellbore below the expandable packer element through the longitudinal opening to equalize a pressure in the wellbore above and below the expandable packer element; determining, in real time, at least one parameter related to the creation or enhancement of the at least one fracture; disengaging the expandable packer element from the casing; and moving the packer apparatus to another formation adjacent the well and repeating the step of displacing a low-molecular-weight fluid down the work string and into the wellbore to create or extend at least one fracture in the formation.

Therefore, the present invention is well adapted to carry out the objects and attain the ends and advantages mentioned as well as those that are inherent therein. While the invention has been depicted and described by reference to particular embodiments of the invention, such a reference does not imply a limitation on the invention, and no such limitation is to be inferred. The invention is capable of considerable modification, alteration, and equivalents in form and function, as will occur to those ordinarily skilled in the pertinent arts and having the benefit of this disclosure. The depicted and described embodiments of the invention are exemplary only, and are not exhaustive of the scope of the invention. Consequently, the invention is intended to be limited only by the spirit and scope of the appended claims, giving full cognizance to equivalents in all respects.

What is claimed is:

1. A method of treating a subterranean formation intersected by a wellbore comprising:

   - lowering a work string having a first packer apparatus connected to a lower end of the work string to a desired location in the wellbore, the work string being communicated with the wellbore through a longitudinal opening defined by the first packer apparatus, the first packer apparatus comprising: a packer mandrel; and an expandable packer element disposed about the packer mandrel; compressing the expandable packer element by lowering the packer mandrel relative to the expandable packer element thereby expanding the packer element outward to engage and seal a casing in the wellbore below the formation, wherein the compressing step seals the longitudinal opening to prevent communication therethrough;

   - displacing a low-molecular-weight fluid down the work string and into the wellbore through a flow port defined in the work string above the first packer apparatus, so as to create or extend at least one fracture in the subterranean formation, the low-molecular-weight fluid having the capability of enhancing the regain permeability of the formation; unsealing the longitudinal opening after the displacing step to communicate a portion of the wellbore above the expandable packer element with a portion of the wellbore below the expandable packer element through the longitudinal opening to equalize a pressure in the wellbore above and below the expandable packer element; and

   - disengaging the expandable packer element from the casing.

2. The method of claim 1 wherein the work string has a second packer apparatus connected therein, the second packer apparatus being located above the formation, the method further comprising: actuating the second packer apparatus to seal the wellbore above the formation.

3. The method of claim 1 further comprising:

   - moving the work string to a second desired location in the wellbore;

   - compressing the expandable packer element by lowering the packer mandrel relative to the expandable packer element thereby expanding the packer element outward to engage and seal a casing in the wellbore below the formation, wherein the compressing step seals the longitudinal opening to prevent communication therethrough; displacing a low-molecular-weight fluid down the work string and into the wellbore through a flow port defined in the work string above the first packer apparatus, so as to create or extend at least one fracture in the subterranean formation, the low-molecular-weight fluid having the capability of enhancing the regain permeability of the formation; unsealing the longitudinal opening after the displacing step to communicate a portion of the wellbore above the expandable packer element with a portion of the wellbore below the expandable packer element through the longitudinal opening to equalize a pressure in the wellbore above and below the expandable packer element; and

   - disengaging the expandable packer element from the casing.
element to seal the casing and seal the longitudinal opening in the first packer apparatus after the moving step;
displacing a second fluid down the work string into the wellbore above the first packer apparatus; and
reopening the longitudinal opening to equalize the pressure above and below the expandable packer element of the first packer apparatus after the step of displacing a second fluid down the work string.

4. The method of claim 1 wherein the first packer apparatus further comprises: a drag sleeve disposed about the packer mandrel, the drag sleeve being slidable relative to the packer mandrel; and an equalizing valve connected to a lower end of the drag sleeve and extending upwardly therefrom into the packer mandrel.

5. The method of claim 1 further comprising the step of moving the packer apparatus to another formation adjacent the well and repeating the step of displacing a low-molecular-weight fluid down the work string and into the wellbore to create or extend at least one fracture in the formation.

6. The method of claim 1 wherein the equalizing valve may be moved between the open and closed positions by reciprocation of the work string.

7. The method of claim 1 wherein the equalizing valve defines a generally cylindrical outer surface, and wherein in the closed position the generally cylindrical outer surface sealingly engages an inner surface of the packer mandrel.

8. The method of claim 1 wherein an interior of the work string is in communication with the wellbore through flow ports defined in the work string above the packer element so that a fluid may be communicated into the formation through the flow ports when the equalizing valve is in the closed position, and wherein the portion of the wellbore above the packer element is in communication with the portion of the wellbore below the packer element through the flow ports, the packer mandrel, and the drag sleeve into the wellbore when the equalizing valve is in the open position in order to equalize the pressure in the wellbore above and below the packer element.

9. The method of claim 1 wherein the equalizing valve moves from the open position to the closed position when the packer apparatus is actuated to expand the packer element to sealingly engage the wellbore.

10. The method of claim 1 wherein the longitudinal opening has a reduced diameter portion, wherein the equalizing valve comprises a generally tubular element disposed in the longitudinal opening, and wherein the equalizing valve is moved between the open and closed positions by moving the equalizing valve in and out of the reduced diameter portion to seal and open the longitudinal opening.

11. The method of claim 1 wherein the equalizing valve moves between the open and the closed positions as the packer apparatus is moved between the set and unset positions.

12. The method of claim 1 wherein the equalizing valve may be moved from the closed position to the open position by pulling upward on the work string.

13. The method of claim 1 wherein the low-molecular-weight fluid has an average molecular weight in the range of from about 100,000 to about 250,000.

14. The method of claim 1 wherein the low-molecular-weight fluid has a viscosity of at least about 2 cP, where the viscosity is measured at about 25° C.

15. The method of claim 1 wherein the low-molecular-weight fluid comprises an acid system.

16. The method of claim 15 wherein the acid system comprises a viscosifier.

17. The method of claim 16 wherein the viscosifier is present in the acid system in an amount in the range of from about 0.002% to about 0.035% by volume.

18. The method of claim 16 wherein the viscosifier comprises an emulsifier or a surfactant.

19. The method of claim 15 wherein the acid system comprises a hydrochloric acid based delayed carbonate acid system.

20. The method of claim 15 wherein the acid system comprises a hydrofluoric acid based delayed carbonate acid system.

21. The method of claim 1 wherein the low-molecular-weight fluid comprises water.

22. The method of claim 1 wherein the low-molecular-weight fluid comprises water, a substantially fully hydrated depolymerized polymer, and a crosslinking agent.

23. The method of claim 22 wherein the substantially fully hydrated depolymerized polymer is a depolymerized polysaccharide.

24. The method of claim 22 wherein the substantially fully hydrated depolymerized polymer is selected from the group consisting of hydroxypolyglycur, carboxymethylhydroxypolyglycur, carboxymethylglycur, hydroxyethylglycur, and carboxymethylhydroxethylglycur.

25. The method of claim 22 wherein the substantially fully hydrated depolymerized polymer is present in the low-molecular-weight fluid in an amount in the range of from about 0.2% to about 5% by weight of the water therein.

26. The method of claim 22 wherein the crosslinking agent is a boron-based compound, xyle, colemanite, a compound that comprises zirconium IV ions, a compound that comprises titanium IV ions, an aluminum compound, or a compound that comprises antimony ions.

27. The method of claim 22 wherein the crosslinking agent is present in the low-molecular-weight fluid in an amount in the range of from about 50 ppm to about 5000 ppm active crosslinker.

28. The method of claim 1 wherein the low-molecular-weight fluid further comprises a pH-adjusting compound, a delayed definer, a buffer, a surfactant, a clay stabilizer, a fluid loss control agent, a scale inhibitor, a demulsifier, a bactericide, a breaker, an activator, or a mixture thereof.

29. A method of reducing the cost of enhancing production from multiple formations penetrated by a well bore by stimulating multiple formations, on a single trip through the well bore, with a fluid that minimizes damage to the formation comprising:

lowering a work string having a first packer apparatus connected to a lower end of the work string to a desired location in the wellbore, the work string being communicated with the wellbore through a longitudinal opening defined by the first packer apparatus, the first packer apparatus comprising:
a packer mandrel; and
an expandable packer element disposed about the packer mandrel;
compressing the expandable packer element by lowering the packer mandrel relative to the expandable packer
element thereby expanding the packer element outward to engage and seal a casing in the wellbore below the formation, wherein the compressing step seals the longitudinal opening to prevent communication therethrough;

displacing a low-molecular-weight fluid down the work string and into the wellbore through a flow port defined in the work string above the first packer apparatus, so as to create or enhance at least one fracture in the subterranean formation, the low-molecular-weight fluid having the capability of enhancing the regain permeability of the formation;

unsealing the longitudinal opening after the displacing step to communicate a portion of the wellbore above the expandable packer element with a portion of the wellbore below the expandable packer element through the longitudinal opening to equalize a pressure in the wellbore above and below the expandable packer element;

disengaging the expandable packer element from the casing; and

moving the packer apparatus to another formation in the wellbore and repeating the step of displacing a low-molecular-weight fluid down the work string and into the wellbore to create or extend at least one fracture in the formation.

30. The method of claim 29 wherein the low-molecular-weight fluid has an average molecular weight in the range of from about 100,000 to about 250,000.

31. The method of claim 29 wherein the low-molecular-weight fluid has a viscosity of at least about 2 cP, where the viscosity is measured at about 25° C.

32. The method of claim 29 wherein the low-molecular-weight fluid comprises an acid system.

33. The method of claim 32 wherein the acid system comprises a viscosifier.

34. The method of claim 33 wherein the viscosifier is present in the acid system in an amount in the range of from about 0.002% to about 0.05% by volume.

35. The method of claim 33 wherein the viscosifier comprises a surfactant.

36. The method of claim 32 wherein the acid system comprises a hydrochloric acid based delayed carbonate acid system.

37. The method of claim 32 wherein the acid system comprises a hydrofluoric acid based delayed carbonate acid system.

38. The method of claim 29 wherein the low-molecular-weight fluid comprises water.

39. The method of claim 29 wherein the low-molecular-weight fluid comprises water, a substantially fully hydrated depolymerized polymer, and a crosslinking agent.

40. The method of claim 39 wherein the substantially fully hydrated depolymerized polymer is a depolymerized polysaccharide.

41. The method of claim 39 wherein the substantially fully hydrated depolymerized polymer is selected from the group consisting of hydroxypropyl guar, carboxymethylhydroxypropyl guar, carboxymethylguar, hydroxyethylguar, and carboxymethylhydroxyethyl guar.

42. The method of claim 39 wherein the substantially fully hydrated depolymerized polymer is present in the low-molecular-weight fluid in an amount in the range of from about 0.2% to about 5% by weight of the water therein.

43. The method of claim 39 wherein the crosslinking agent is a boron-based compound, teulexite, colemite, a compound that comprises zirconium IV ions, a compound that comprises titanium IV ions, an aluminum compound, or a compound that comprises antimony ions.

44. The method of claim 39 wherein the crosslinking agent is present in the low-molecular-weight fluid in an amount in the range of from about 50 ppm to about 5000 ppm active crosslinker.

45. The method of claim 39 wherein the low-molecular-weight fluid further comprises a pH-adjusting compound, a delayed delinker, a buffer, a surfactant, a clay stabilizer, a fluid loss control agent, a scale inhibitor, a demulsifier, a bactericide, a breaker, an activator, or a mixture thereof.

46. A method of enhancing production, in real time, from multiple subterranean formations penetrated by a well bore during a single trip through the well bore, comprising

lowering a work string having a first packer apparatus connected to a lower end of the work string to a desired location in the wellbore, the work string being communicated with the wellbore through a longitudinal opening defined by the first packer apparatus, the first packer apparatus comprising:

a packer mandrel; and

an expandable packer element disposed about the packer mandrel;

compressing the expandable packer element by lowering the packer mandrel relative to the expandable packer element thereby expanding the packer element outward to engage and seal a casing in the wellbore below the formation, wherein the compressing step seals the longitudinal opening to prevent communication therethrough;

displacing a low-molecular-weight fluid down the work string and into the wellbore through a flow port defined in the work string above the first packer apparatus, so as to create or extend at least one fracture in the subterranean formation, the low-molecular-weight fluid having the capability of enhancing the regain permeability of the formation;

unsealing the longitudinal opening after the displacing step to communicate a portion of the wellbore above the expandable packer element with a portion of the wellbore below the expandable packer element through the longitudinal opening to equalize a pressure in the wellbore above and below the expandable packer element;

determining, in real time, at least one parameter related to the creation or enhancement of the at least one fracture;

disengaging the expandable packer element from the casing; and

moving the packer apparatus to another formation adjacent the well and repeating the step of displacing a low-molecular-weight fluid down the work string and into the wellbore to create or extend at least one fracture in the formation.

47. The method of claim 46 wherein the step of determining, in real time, at least one parameter related to the
creation or enhancement of the at least one fracture comprises determining, in real time, that at least one fracture therein has been created or enhanced to a desired extent.

48. The method of claim 47 wherein the step of relocating the tool assembly within the well bore to another desired location in the same, or different, formation is performed after the step of determining, in real time, that at least one fracture therein has been created or enhanced to a desired extent.

49. The method of claim 46 further comprising performing a remedial step after the step of determining, in real time, at least one parameter related to the creation or enhancement of the at least one fracture.

50. The method of claim 49 wherein the remedial step comprises reducing the concentration of a proppant present in the low-molecular-weight fluid.

51. The method of claim 49 wherein the remedial step comprises reducing the viscosity of the low-molecular-weight fluid.

52. The method of claim 46 wherein the low-molecular-weight fluid has an average molecular weight in the range of from about 100,000 to about 250,000.

53. The method of claim 46 wherein the low-molecular-weight fluid has a viscosity of at least about 2 cP where the viscosity is measured at about 25°C.

54. The method of claim 46 wherein the low-molecular-weight fluid comprises an acid system.

55. The method of claim 54 wherein the acid system comprises a viscosifier.

56. The method of claim 55 wherein the viscosifier is present in the acid system in an amount in the range of from about 0.002% to about 0.035% by volume.

57. The method of claim 55 wherein the viscosifier comprises an emulsifier or a surfactant.

58. The method of claim 54 wherein the acid system comprises a hydrochloric acid based delayed carbonate acid system or a hydrofluoric acid based delayed carbonate acid system.

59. The method of claim 46 wherein the low-molecular-weight fluid comprises water.

60. The method of claim 46 wherein the low-molecular-weight fluid comprises water, a substantially fully hydrated depolymerized polymer, and a crosslinking agent.

61. The method of claim 60 wherein the substantially fully hydrated depolymerized polymer is a depolymerized polysaccharide.

62. The method of claim 60 wherein the substantially fully hydrated depolymerized polymer is selected from the group consisting of hydroxypropylylguar, carboxymethylhydroxypropylguar, carboxymethylguar, hydroxyethylguar, and carboxymethylhydroxyethylguar.

63. The method of claim 60 wherein the substantially fully hydrated depolymerized polymer is present in the low-molecular-weight fluid in an amount in the range of from about 0.2% to about 5% by weight of the water therein.

64. The method of claim 60 wherein the crosslinking agent is a boron-based compound, urea, urea, colemancite, a compound that comprises zirconium IV ions, a compound that comprises titanium IV ions, an aluminum compound, or a compound that comprises antimony ions.

65. The method of claim 60 wherein the crosslinking agent is present in the low-molecular-weight fluid in an amount in the range of from about 50 ppm to about 5000 ppm active crosslinker.

66. The method of claim 46 wherein the low-molecular-weight fluid further comprises a pH-adjusting compound, a delayed delinker, a buffer, a surfactant, a clay stabilizer, a fluid loss control agent, a scale inhibitor, a demulsifier, a bactericide, a breaker, an activator, or a mixture thereof.

67. A method of enhancing production from multiple subterranean formations penetrated by a well bore during a single trip through the well bore, comprising lowering a work string having a first packer apparatus connected to a lower end of the work string to a desired location in the wellbore, the work string being communicated with the wellbore through a longitudinal opening defined by the first packer apparatus, the first packer apparatus comprising:

a packer mandrel; and

an expandable packer element disposed about the packer mandrel;

compressing the expandable packer element by lowering the packer mandrel relative to the expandable packer element thereby expanding the packer element outward to engage and seal a casing in the wellbore below the formation, wherein the compressing step seals the longitudinal opening to prevent communication there-through;

displacing a low-molecular-weight fluid down the work string and into the wellbore through a flow port defined in the work string above the first packer apparatus, so as to create or extend at least one fracture in the subterranean formation, the low-molecular-weight fluid having the capability of enhancing the regain permeability of the formation;

unsealing the longitudinal opening after the displacing step to communicate a portion of the wellbore above the expandable packer element with a portion of the wellbore below the expandable packer element through the longitudinal opening to equalize a pressure in the wellbore above and below the expandable packer element;

disengaging the expandable packer element from the casing; and

moving the packer apparatus to another formation adjacent the well and repeating the step of displacing a low-molecular-weight fluid down the work string and into the wellbore to create or extend at least one fracture in the formation.

68. The method of claim 67 wherein the low-molecular-weight fluid has an average molecular weight in the range of from about 100,000 to about 250,000.

69. The method of claim 67 wherein the low-molecular-weight fluid has a viscosity of at least about 2 cP where the viscosity is measured at about 25°C.

70. The method of claim 67 wherein the low-molecular-weight fluid comprises an acid system.

71. The method of claim 70 wherein the acid system comprises a viscosifier.

72. The method of claim 71 wherein the viscosifier is present in the acid system in an amount in the range of from about 0.002% to about 0.035% by volume.

73. The method of claim 71 wherein the viscosifier comprises an emulsifier or a surfactant.
74. The method of claim 70 wherein the acid system comprises a hydrochloric acid based delayed carbonate acid system or a hydrofluoric acid based delayed carbonate acid system.

75. The method of claim 67 wherein the treatment fluid comprises water.

76. The method of claim 67 wherein the treatment fluid comprises water, a substantially fully hydrated depolymerized polymer, and a crosslinking agent.

77. The method of claim 76 wherein the substantially fully hydrated depolymerized polymer is a depolymerized polysaccharide.

78. The method of claim 76 wherein the substantially fully hydrated depolymerized polymer is selected from the group consisting of hydroxypropylguar, carboxymethylhydroxypropylguar, carboxymethylguar, hydroxyethylguar, and carboxymethylhydroxyethylguar.

79. The method of claim 76 wherein the substantially fully hydrated depolymerized polymer is present in the low-molecular-weight fluid in an amount in the range of from about 0.2% to about 5% by weight of the water therein.

80. The method of claim 76 wherein the crosslinking agent is a boron-based compound, ulexite, colemanite, a compound that comprises zirconium IV ions, a compound that comprises titanium IV ions, an aluminum compound, or a compound that comprises antimony ions.

81. The method of claim 76 wherein the crosslinking agent is present in the low-molecular-weight fluid in an amount in the range of from about 50 ppm to about 5000 ppm active crosslinker.

82. The method of claim 67 wherein the low-molecular-weight fluid further comprises a pH-adjusting compound, a delayed delinker, a buffer, a surfactant, a clay stabilizer, a fluid loss control agent, a scale inhibitor, a demulsifier, a bactericide, a breaker, an activator, or a mixture thereof.

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