Process of hydraulic fracturing to create a layered proppant pack structure alongside the faces of the fracture to prevent formation fines to damage fracture conductivity

Method of hydraulic fracturing oil and gas wells to create a layered proppant pack structure alongside the faces of the fracture to prevent formation fines (10) to damage the fracture conductivity over time characterized in that it comprises several distinct steps:

i) Creating a hydraulic fracture (11) and transporting into the so opened fracture a "fine grained proppant" (5) (equally called "fine proppant" or "fine grained proppant" or "support proppant")

ii) Shutting-in the well to let the fracture close and the confinement stress of the reservoir to be re-established so as to compress the fine proppant against the walls of the fracture and resulting in a strong adhesion of the fine grained proppant against the walls of the fracture via mechanical and/or chemical mechanisms.

iii) Re-opening the same hydraulic fracture using a conventional fracturing technique to place a "larger or much larger proppant" (30) (equally called "coarse proppant" or "conductive proppant") in the middle of the fracture width and therefore between the layers of the fine proppant remaining in place against the walls of the fracture because of the strong interactions previously established during the shut-in, and acting as a "support" for the larger proppant, the said fine "support" proppant allowing the said larger proppant to ensure and retain a high conductivity for a long period of time.

**FIG. 8**
Invention – Well in production.

- Formation fines from crushed formation: 40
- Formation fines: 10
- Proppant fines: 50
- Frac gel or fluid: 20
- Large proppant: 30
- Small proppant: 5
FIELD OF THE INVENTION

[0001] This invention relates to a method of hydraulic fracturing specially designed to address challenging reservoir conditions such as but not limited to poorly consolidated reservoirs. In such reservoirs, proppant embedment and formation fines invasion are notorious to dramatically reduce fracture conductivity and therefore impair the performance of the well. These are problems typically encountered with shales, coal and other soft rocks reservoirs. But formation fines invasion and migration are taking place in many different cases, not just in soft rocks and are experienced in a large proportion of fracturing treatments.

[0002] This is applicable to any kind of hydraulic fracture treatment, no matter what specific application it is aiming at. It is applicable to vertical, horizontal or inclined fractures, to oil, gas or condensates wells or water wells. With reasonable adaptations, known to the skilled man, the process is perfectly applicable to Heavy Oil Reservoirs often associated with poor mechanical integrity and the presence of large amount of formation fines. The layered structure of the proppant pack described in this application makes the fracturing technique a much more attractive solution for many heavy oil reservoirs.

BACKGROUND OF THE INVENTION. PRIOR ART.

[0003] The problem of hydraulic fracture conductivity is very well described by eminent industry experts namely in a brochure produced by Halliburton entitled "Conductivity Endurance" and published in 2005 as a supplement to the "E&P" and "Oil and Gas Investor" Magazines. The brochure contains 13 articles and all aspects of conductivity endurance are overviewed.


[0004] Among the 13 articles included in the brochure, a few are particularly interesting:

- Stick to Tacky. It pays. (From Halliburton on their SMA-SandWedge product)
- Not all Resin-Coated Proppants are created equal. (From Halliburton on their Liquid Resin System - Expedite)

[0005] An extensive review of re-fracting operations by M. C. Vincent is also very interesting: SPE 119143: Examining our assumptions - Have oversimplifications jeopardized our ability to design optimal fracture treatments?

[0006] M.C. Vincent made a presentation January 2009 with many drawings of this SPE paper. It is available at:

http://www.aboutoilandgas.org/events/dl/docs/09_10_Presentations/MikeVincent.pdf

Definition of each and every term used in this memo can be found at:

http://www.glossary.oilfield.slb.com/default.cfm

[0007] The said Glossary is constantly up-dated.

[0008] It can also be found in a reference book: Reservoir Stimulation - 3rd Edition by M. Economides and K. Nolte describing all aspects of the hydraulic fracturing technology very extensively.

A. DEFINITIONS AND COMMON KNOWLEDGE.

[0009] Most if not all of the technical terms used in this patent application are commonly used by the skilled man. The same is true for "common knowledge". As an example, a general "hydraulic fracturing process" is part of the common knowledge. We are however, just to be as complete as possible, and even though those wordings are well known, try to list here-below a series of terms and expressions and their definitions, generally taken from the prior art.

[0010] Within each definition or piece of common knowledge, the terms which will be used, or might be used, in this application are additionally underlined in bold.

[0011] In the following, unless expressly indicated to the contrary, each and every technical term will be understood as defined in the SCHLUMBERGER Oilfield Glossary (www.)

General Description of Hydraulic Fracturing Operations From USP 4,549,608 to Stowe et al.

[0012] The operation mainly consists of
The openings of the permeable media. In the case of reservoirs to be fractured this takes place in particular but not on the surface of a permeable medium when subjected to a pressurized fluid containing said material to a large extent. 

Leak-Off and "filtercake"

The process can inject first a fine grain sand no larger than 100 mesh. The said gravel packing sand is 40-60 mesh.
cake is the direct result of the leak-off process in which the material contained in the fracturing fluid cannot penetrate the permeable portion of the rock, is filtered out of the fluid and accumulates on parts of the faces of the fractures.

"Shut in"

Well shut-ins occur very often over the life of a well and during many operations. In its simplest form it consists at closing the valve at the wellhead. No matter what the pressure at the bottom of the well is when the shut-in is initiated, this pressure will stabilize back to the pressure of the reservoir. If the permeability of the formation is low or very low, the time needed to get back the bottom-hole pressure back to the reservoir pressure can be very long.

[0021] This can play both ways. After a long production time, the bottom-hole pressure is below the reservoir pressure and time to get it up back to the reservoir pressure can take many hours. After an injection test or a fracturing treatment, the bottom-hole pressure is higher than the reservoir pressure and the time it takes to get it back down to the reservoir pressure can also take many hours.

[0022] To shorten these times required to re-establish bottom-hole pressures at specific values after injection and/or fracturing, the valve at the well-head can be carefully open and some pressure released from the well-head. This is considered as part of a well shut-in operation.

Reverse flow / Flow back From USP 3, 933,205

[0023] Phenomenon that occurs when the well is "shut in" or allowed to flow back to cause low fracture pressure; that is a pressure below the fracturing pressure.

[0024] This reverse flow lowers the pressure in the fracture at a faster rate and to a lower level than does merely shutting the well in and allowing fluid loss from the fracture to the formation to lower fracture pressure. Reverse flow causes a higher rate of pressure change and thus creates a greater pressure differential between the formation and the fracture. This pressure differential causes a higher rate of flow of the fracturing fluid across the fracture formation interface. The higher differential pressure and flow rate generates correspondingly higher earth stresses on the fracture face and produces more spalls than does the shut in method described above.

[0025] When the hydraulic pressure in the fracture is lowered, eg. by reverse flow, below the matrix pressure, then the fracturing fluid in the matrix flows back into the fracture. This fluid flow creates earth stresses at the formation face and adjustment of these earth stresses produces spalls.

[0026] The amount of earth stresses produced by the present invention is a direct function of the pressure differential between the matrix and the fracture. Thus a rapid drop in fracture pressure, such as is accomplished by reverse flow, generates high earth stresses on the fracture face.

Dual Frac

[0027] This technique reduces the proppant convection that would otherwise adversely affect fracturing treatment results. In some fracturing operations, a radial fracture growth pattern occurs when the initial or subsequent net fracturing pressure during the job exceeds the stress contrast between formations. This condition may result in unwanted downward fracture growth out of the zone of interest. In addition, the combination of a radial growth pattern and density contrasts in treatment fluid may cause proppant convection to the bottom of the fracture, which could impair production results. Dual fracturing consists of an initial "settle" fracturing treatment followed by a main treatment. The settle-frac treatment features a low-viscosity fluid with high breaker loading and a proppant to create enough length and settled height. This treatment creates an artificial barrier that minimizes downward fracture growth and proppant convection.

Fracture conductivity in soft rock. TSO (Tip Screen-Out) Technique From USP 5 325, 921 to Nguyen and al

[0028] Soft formations, such as poorly consolidated or non consolidated sandstones, can be fractured and filled with proppant. However, as the fracture closes, the proppant becomes embedded or absorbed by the soft rock matrix.

[0029] To limit the negative impact of this effect, the fracture in soft formations should be as wide as possible. One effective method for obtaining a wide fracture is tip screenout (TSO) fracturing.

General description of the Tip Screen-Out Technique.

[0030] Early Screen-outs are to be avoided in fracturing operations. That refers to the formation of a proppant bridge in the fracture, sometimes close to the well-bore. Correct placement of the remaining of the proppant becomes impossible and quickly accumulates just behind the bridge. Surface pressures can increase very quickly and the operations has to
be stopped prematurely.

[0031] In the Tip Screen-Out technique, this bridge is created deliberately but at the tip of the fracture, i.e. at its very end. And the proppant then accumulates behind the bridge at the tip of the fracture (Hence the name Tip Screen-out) and progressively completely fill the fracture. This technique requires a good knowledge of the leak-off properties of the fracturing fluid. It is more delicate but allows for the creation of very wide, highly conductive fractures of great benefit in formations with good productivity.

[0032] It is also of benefit in soft formations and for the same reason. The pressure increase resulting from the tip screen-out causes the fracture to open more widely allowing for more proppant to be placed. A wide fracture can accommodate more embedment and still maintain acceptable conductivity.

[0033] "Frac faces" or "Frac Walls" designate the faces of the hydraulic fracture created in the reservoir. Those faces are vertical in the most frequent case of a vertical hydraulic fracture. However one rarely creates fractures that are perfectly vertical. Most of the time they are slightly inclined relative to the verticality.

[0034] The technique describes in this document refers to conventional, vertical hydraulic fractures.

[0035] The same technique, however is also applicable to strongly inclined or even horizontal fractures that are more representative of the fractures created in very shallow reservoirs. In such a situation, the layer of fine grained proppant placed against the top fracture wall could easily fall onto the bottom fracture wall during the sequences of operations. But the tacky material and the embedment will keep a large portion of it in place. The technique is therefore applicable to all hydraulic fractures, no matter what their orientations are.

B. TECHNICAL CHALLENGES

The key issue in Hydraulic Fracturing: The Fracture Conductivity over time.

[0036] As a factual reminder, a fracturing operation has the objective of creating so called "fractures" into an oil reservoir when the natural permeability of the said reservoir is considered as too low to provide a sufficient flow of oil to the well-bore. To that purpose, a chemical fluid or gel, optionally loaded with a fine sand or a proppant, is pumped under heavy pressure into the "perforations" opened into the reservoir (see above section "Definitions") at such a pressure (applied from the surface) so as to literally "fracture" the rocks and propagating this hydraulic fracture into the reservoir as the pumping of the fracturing fluid continues at the top of the well.

[0037] A key objective of the operation is to fill the so-created "hydraulic fracture" with a "proppant pack" featuring a high "conductivity" that will keep the fracture open when the pumping is stopped and maintained a high fracture conductivity to let the fluids from the formation flow to the well-bore through the said pack.

[0038] "Fines" of different origins (see the above section "Definitions") can impair the process. They can be present in the reservoir even before the treatment. They can be generated by the mechanical degradation of the fracture faces when the pumping is stopped and the reservoir pressure is applied against the fracture faces. Or they can come from a partial crushing of the proppant itself. These fines can be transported by the flow of reservoir fluids, oil, natural gas, water or any mix of, and migrate into the proppant pack where they will usually cause a reduction of its conductivity, sometimes in a spectacular fashion. Sometimes, successive fracturing operations have to be performed during the well life, so as to periodically restore the said conductivity.

[0039] The technical challenge is therefore to either eliminate or reduce the amount of the fines generated in the hydraulic fracturing process and/or to prevent these fines to reduce the conductivity of the proppant pack, not only just during the operation but for as long as possible during the life of the well.

[0040] For many years the industry thought that conventional hydraulic fracturing treatments were producing fractures with conductivity well in excess of what was necessary to produce the well adequately. This was based on huge oversimplifications and poor usage of some laboratory tests. Crush tests and Conductivity tests in particular, done as per API and then ISO industry standards, were used to predict in-situ fracture conductivity when they were never designed for that purpose (SPE119242: How to use and misuse proppants crush tests - Exposing the top 10 myths). In many cases, the actual conductivity observed under realistic conditions is 50 to 1000 times lower than the conductivity measured in laboratories following industry tests standards.

[0041] There is a large number of factors leading to in-situ fracture conductivity well below laboratory data: poor proppant placement, residual gel damage, proppant embedment, formation fines generation, invasion and migration, proppant flow-back etc... Accordingly many different techniques and/or solutions were investigated and developed over the years to address the causes of the problem: resin-coated proppants, high strength proppant, fracturing fluid with better clean-up properties etc.

[0042] Corresponding definitions and common knowledge are as follows:

**Proppant strength.** When a hydraulic fracture is created, the in-situ stresses must be overcome to open and propagate the fracture. Once the hydraulic pressure in the fracture is reduced, these same stresses tend to close
the fracture. If the proppant is not strong enough to withstand the closure stress of the fracture, it will be crushed and the permeability of the propped fracture will be drastically reduced. The smaller particles resulting from crushing the proppant grains can significantly reduce the permeability of the pack. The strength of a proppant is measured via a crush test following the ISO 13503-2 procedure.

**Proppant placement.** Proppants are carried into the fracture using viscous fracturing fluid. However sedimentation of proppant particles can occur during pumping and after pumping but before fracture closure. This sedimentation can lead to an accumulation of proppant particles in the lower (bottom) part of the vertical fracture. The higher (Top) part of a vertical fracture can then not have enough proppant to be conductive enough.

**Proppant embedment.** Formation strength may not be high enough to resist the stress applied onto it once the fracturing hydraulic pressure is released and the reservoir stress is applied to the faces of the fracture via the proppant pack. In which case rather than having the proppant crushed, we have the proppant particles indenting into the formation walls and in some cases crushing the formation grains. This is referred to as proppant embedment. This crushing can lead to the formation of large amount of formation fines that can migrate into the proppant pack when oil and/or gas production is started and lead to a continuous and significant impairment of the proppant pack conductivity.

**Spalling:** The process of displacing crushed fine formation particles. During oil and/or gas production such spalling will cause these fines to invade the proppant pack and later possibly migrate within the proppant pack.

**Proppant flowback:** Proppant can flowback into the well-bore after hydraulic fracturing treatment is completed. It is a serious concern in the industry as it can decrease the amount of proppant in the critical area close to the well-bore and reduce the overall conductivity of the fracture. Proppant flow-back can be minimized by using resin-coated proppants, fibers or deformable particles.

**Formation fines generation, invasion and migration.**

[0043] While the techniques and products designed to combat fines improved, the industry was also expanding the domains of application of hydraulic fracturing towards a wider range of reservoir characteristics making the achievement of adequate fracture conductivity even more challenging. In particular, the shift towards soft rocks, shales and coal made the problems of embedment and formation fines generation, invasion and migration a very critical issue. Such weak subterranean formations release fines from the faces of the created fractures as a result of spalling and scouring of the formation wall which causes formation particulates to invade the proppant pack: this is what we refer to as formation fines generation. Invasion refers to the transfer of these fines from the formation into the proppant pack. Migration refers to the movement of fines within the proppant pack towards the well-bore. This migration can be the worst mechanism of all to destroy the productivity of the well since it damages the fracture conductivity in the most critical part of the fracture, the one closed to the well-bore.

[0044] **Fines generated by the proppant:** Fines can be generated by the proppant itself. A high fracture closure stress may apply to the proppant a stress that is beyond its strength and some particles of proppant can break. To avoid this the industry is selecting the type of proppants to be used based on the closure stress to be expected during the life of the well. However even when the right proppant is selected one can still get some fines within the proppant pack resulting from the destruction of some proppant grains.

**Size Exclusion Process and Saucier Criteria.**

[0045] Historically the control of fines invasion used to be based on classic size exclusion process (Saucier criteria). This technique was initially developed as a Sand Control technique: Poorly consolidated formations tend to produce sand along oil and/or gas production. A technique to avoid production of sand in the well-bore consisted in using in the annulus of the well-bore a calibrated particle material whose PSD (Particle size distribution) was selected to prevent the invasion of fines/sand. The industry refers to this calibrated particle size material as the “gravel” to differentiate it from the particles coming from the formation usually referred to as sand or fines. In this technique, fines/sand migrating from the reservoir can be classified in 3 categories based on the criteria developed by Saucier using the Particle Size Distribution of the fines and of a particulate gravel pack.

- If the fines/sand average particle size distribution (PSD) is larger than 1/6th the average PSD of the particulate pack, fines/sand cannot penetrate the pack. They are excluded. Hence the name of the technique.
- If the fines/sand average PSD are smaller than 1/12th of the average PSD of the particulate pack, they can mostly
flow through the pack and not cause significant damage.

- If the fines/sand average PSD are in between 1/6th and 1/12th of the average PSD of the particulate pack, they can invade the pack and progressively plug the pack with dramatic impact on the conductivity of the pack.

[0046] These values may vary a little bit depending on the exact shape of the particle size distribution curve of the materials, on the shape of the particles etc... However they have been used for many years as a Sand Control Technique in the oilfield and are very widely accepted. In these applications of sand control techniques, the "gravel" pack is placed in the annulus of the well-bore opposite the production interval of the reservoir from where sand and fines are produced along with oil or natural gas. This size exclusion concept is explained in detail in SPE paper 10631.

[0047] This same concept has been adapted to hydraulic fracturing. Just like gravel was sized to formation grain sizes (sand or fines) in gravel operations, proppant was sized to formation grain sizes in fracturing operations. As per the criteria of Saucier, the average Particle Size Distribution (PSD) of the proppant must not be larger than 6 times the average PSD of the formation grains or fines to prevent any invasion of the formation grains/fines into the proppant pack. This approach is however limited and penalizing because formations are almost always heterogeneous. To make sure the formation grains/fines cannot penetrate the proppant pack, the average PSD of the proppant pack must be tailored to the part of the reservoir that has the smallest grains/fines. The tendency, therefore, is to undersize the proppant pack to exclude the smallest formation grain sizes likely to be encountered. As a result the proppant pack designed per this method has a low to very low conductivity and therefore the well has a productivity well below what is possible based on reservoir characteristics.

Resin-coated Proppants

[0048] The industry then turned towards resin-coated proppants. These resin-coated proppants were initially developed to combat proppant flow-back which was one of the causes of poor fracture conductivity. But these resin-coated sands were also recognized for decreasing the amount of mobile fines produced by the crushing of the proppant when submitted to the fracture closure stresses and production cycling. However conventional resin-coated sands are not very effective in preventing fines invasion from the formation. Many types of resin coated materials were introduced over the years by a number of suppliers: different types of substrates: sand, ceramics, others. Different types of coatings: cured, curable or semi-cured based on a large variety of chemical compositions. Different structure of coatings: Single coat or multiple coats. Coatings applied in a plant or on-the-fly during the fracturing treatment.

[0049] Among the main suppliers: Carbo Ceramics, Saint Gobain, Santrol, Hexion, Atlas, etc.

[0050] All Service Companies offer this type of materials, usually buying them from Vendors specialized in this field but sometimes very active in formulating and patenting concepts and formulations themselves. Their usage nowadays is mostly used to combat proppant flow-back as opposed to combat invasion and migration of formation fines.

The Surface Tackiness concept applied to hydraulic fracturing as invented by Halliburton.

[0051] The concept of resin-coated proppants was developed further by Halliburton™ to specifically address the problem of formation fines invasion and migration. Halliburton developed a Surface Modification Agent (SMA) making the proppant surface tacky. Two mechanisms were invoked to explain the efficiency of increased surface tackiness: First, a larger proppant pack porosity resulting in higher pack permeability and better tolerance to fines. Second a proppant pack that prevents encroachment of formation fines into the pack and migration of fines because of the immobilization of fines through adhesion on the proppant grains coated with the tacky material. This concept is covered by US Patent 5,775,425. The product was commercialized under the name of SandWedge ® and Halliburton claims to have carried out thousands of jobs. It has been the subject of many SPE publications (SPE 56833).

[0052] To avoid problems experienced during the storage and transport of these tacky materials Halliburton introduced an activated liquid resin system (LRS - Expedite) that can be added on-the-fly (SPE77748).

[0053] The use of tacky materials whereby fine particulate flowback is reduced or prevented is further described in the Halliburton patent USP 5,871,049 to Weaver at al.

[0054] In another related development, Halliburton developed a hardenable resin that remains tacky after hardening, combining in doing so the flow back control and the control of fines within the pack (US Patent 6,725,931)

[0055] Halliburton continues to investigate, patent and publish all possible applications of their surface tackiness concept. Their latest patents:

US Patent 7,261,157 regarding the use of tacky solid particulates as a method of controlling particulates segregation in slurries


US 6047772 (A) (Halliburton) discloses a combination of tacky products with multifunctional agent to form a resin
Fracturing techniques using tacky products as described by Halliburton in US Patent 5,871,049

[0057] A method of treating a subterranean formation has been proposed by Halliburton comprising the steps of:

- introducing a particulate-containing fluid into a fracture created in a subterranean formation;
- admixing with at least a portion of said particulate in said fluid suspension a liquid or solution of a tackifying compound whereby at least a portion of said particulate is at least partially coated by said compound such that the critical resuspension velocity of said at least partially coated particulate is increased by at least about 50 percent when tested at a level of 0.5% active material by weight over said particulate alone with water;
- depositing the tackifying compound coated particulate in the fracture in said subterranean formation;
- and forcing closure of said fracture upon said coated particulate by rapidly flowing back fluid from the formation whereby the tackifying compound coated particulate retards movement of at least a portion of the particulate within said formation during said forced closure.

[0058] In a further patent application, the same Applicant states that upon deposition of the coated material mixture in the formation the coating causes fine particulate adjacent the coated material to adhere upon contact with the coated material thereby creating agglomerates which bridge against other particles in the formation to prevent particulate flowback and fines migration.

[0059] The tackifying compound also may be introduced into the subterranean formation prior to or after introduction of the proppant particulate.

[0060] The coated material is said to be effective in inhibiting the flowback of fine particulate in a porous pack having a size ranging from about that of the proppant material to less than about 600 mesh in intimate admixture with the tackifying compound coated particulates.

[0061] This means that when tacky materials are used the Saucier’s criteria can be very substantially modified and increased from a maximum ratio of 6 as previously described to a value of 30 or more.

[0062] Therefore, as per the Halliburton concept, the adhesion forces created by the tacky coating with the formation fines is enough to prevent fines movement under high confinement stress and in-situ reservoir temperature even with very high Sauciers’ ratio. We will see later that field applications do not support this claim.

Chemistry of Tacky materials. US Patent 5,775,425 by Halliburton

[0063] In this patent, Halliburton describes many types of chemical compounds providing surface tackiness. Any one can be used in our invention using the criteria defined by Halliburton.

[0064] The tackifying compound comprises a liquid or a solution of a compound capable of forming at least a partial coating upon the substrate material with which it is admixed prior to or subsequent to placement in the subterranean formation. In some instances, the tackifying compound may be a solid at ambient surface conditions and upon initial admixing with the particulate and after heating upon entry into the well-bore for introduction into the subterranean formation become a melted liquid which at least partially coats a portion of the particulate. Compounds suitable for use as a tackifying compound comprise substantially any compound which when in liquid form or in a solvent solution will form a non-hardening coating, by themselves, upon the particulate and will increase the continuous critical resuspension velocity of the particulate when contacted by a stream of water as hereinafter described in Example I by in excess of about 30 percent over the particulate alone when present in a 0.5 percent by weight active material concentration. Preferably, the continuous critical resuspension velocity is increased by at least 40 percent over particulate alone and most preferably at least about 50 percent over particulate alone. A particularly preferred group of tackifying compounds comprise polyamides which are liquids or in solvent solution at the temperature of the subterranean formation to be treated such that the polyamides are, by themselves, non-hardening when present on the particulates introduced into the subterranean formation. A particularly preferred product is a condensation reaction product comprised of commercially available polyacids and a polyamine. Such commercial products include compounds such as mixtures of C36 dibasic acids containing some trimer and higher oligomers and also small amounts of monomer acids which are reacted with polyamines. Other polyacids include trimer acids, synthetic acids produced from fatty acids, maleic anhydride and acrylic acid and the like. Such acid compounds are available from companies such as Witco Corporation, Union Camp, Chemtall, and Emery Industries. The reaction products are available from, for example, Champion Technologies, Inc. and Witco Corporation.

[0065] In general, the polyamides of the present invention are commercially produced in batchwise processing of...
polyacids predominately having two or more acid functionalities per molecule with a polyamine. As is well known in the manufacturing industry, the polyacids and polyfunctional amines are introduced into a reactor where, with agitation, the mildly exothermic formation of the amide salt occurs. After mixing, heat is applied to promote endothermic dehydration and formation of the polymer melt by polycondensation. The water of reaction is condensed and removed leaving the polyamide. The molecular weight and final properties of the polymer are controlled by choice and ratio of feedstock, heating rate, and judicious use of monofunctional acids and amines to terminate chain propagation. Generally an excess of polyamine is present to prevent runaway chain propagation. Unreacted amines can be removed by distillation, if desired. Often a solvent, such as an alcohol, is admixed with the final condensation reaction product to produce a liquid solution that can readily be handled. The condensation reaction generally is accomplished at a temperature of from about 225 DEG F. to about 450 DEG F. under a nitrogen sweep to remove the condensed water from the reaction. The polyamines can comprise, for example, ethylenediamine, diethylenetriamine, triethylene tetraamine, amino ethyl piperazine and the like.

[0066] The polyamides can be converted to quaternary compounds by reaction with methylene chloride, dimethyl sulfate, benzylchloride, diethyl sulfate and the like. Typically the quaternization reaction would be effected at a temperature of from about 100 DEG to about 200 DEG F. over a period of from about 4 to 6 hours.

[0067] The quaternization reaction may be employed to improve the chemical compatibility of the tackifying compound with the other chemicals utilized in the treatment fluids. Quaternization of the tackifying compound can reduce effects upon breakers in the fluids and reduce or minimize the buffer effects of the compounds when present in various fluids.

[0068] Additional compounds which may be utilized as tackifying compounds include liquids and solutions of, for example, polyesters, polycarbonates and polycarbamates, natural resins such as shellac and the like.

[0069] The surprising discovery has been made that a tackifying compound can also be produced by the reaction of a polyacid such as previously described with a multivalent ion such as calcium, aluminum, iron or the like. Similarly, various polycationophosphates, polyphosphonates, polysulfates, polycarboxylates, or polysilicates may be reacted with a multivalent ion to yield a tackifying compound. If retardation of the rate of reaction is desired, esters of the above compounds may be utilized which will then react with the multivalent ion as the esters hydrolyze at the subterranean formation temperatures in the treatment fluids. Alternatively, chelates may be formed with known chelating agents such as citric acid, hydroxypropionates and the like to retard the rate of reaction. Further, it has been found possible to generate the tackifying compound in-situ within the subterranean formation by introduction of the polyacid to contact multivalent ions present in the treatment fluid within the subterranean formation. The multivalent ions may be either naturally occurring in the formation or introduced with the treatment fluid.

[0070] It has been discovered that the incorporation of or addition of certain surfactants to the fluid suspension can improve or facilitate the coating of the tackifying compound upon the particulate. The addition of selected surfactants has been found to be beneficial at both elevated fluid salinity and elevated fluid pH as well as at elevated temperatures. The surfactants appear to improve the wetting of the particulates by the tackifying compound. Suitable surfactants include: nonionics, such as, long chain carboxylic esters such as propylene glycol, sorbitol and polyoxyethylenated sorbitol esters, polyoxyethyleneated alkylphenols, alkylphenol, ethoxylates, alkylglucosides, alkanolamine condensates and alkanolamides; anionics, such as, carboxylic acid salts, sulphonic acid salts, sulfuric ester salts and phosphonic and polyphosphoric acid esters; cationics, such as, long chain amines and their salts, quaternary ammonium salts, polyoxyethylenated long chain amines and quaternized polyoxyethylenated long chain amines; and zwitterions, such as n-alkylbetaines.

C. HYDRAULIC FRACTURE CONDUCTIVITY OVER TIME STILL A MAJOR ISSUE.

[0071] In spite of all these efforts, there is very strong evidence that fractures conductivities remain in many cases well below what is required to provide optimum production over time. M.C. Vincent has recently published a paper (SPE119143 referenced in the introduction of this memo) reporting the results of re-fracturing operations. The study covers more than 200 published field studies. As per M. C. Vincent, it was anticipated that the study would identify the major sources of discrepancies between design and observed fracture conductivities. This was not the case. Surprisingly large production gains have been documented after re-fracturing essentially every type of reservoirs - sandstones, shales, coals, carbonates - in low rate and high rate wells, in deep wells, in shallow wells, in production, injection and storage wells. What appears to be common in the results of these field studies is that pressure losses in fractures are greater than typically expected and therefore production increases can be obtained with increases in conductivity. To quote him: "There is good news and bad news. The bad news is that our fracs are often not optimized. The good news is that a large potential remains to increase production from hydraulically stimulated wells".

[0072] These re-fracturing results combined with the observation that formation fines are experienced in a very wide range of conditions but particularly in the fastest growing segment of hydraulic fracturing (shales) lead us to conclude that a new approach in solving the problem of fracture conductivity is needed, in particular for poorly consolidated reservoirs and for those prone to produce large amount of fines.
SUMMARY OF THE INVENTION

A new concept is described to overcome the problem of formation fines invasion into the proppant pack in hydraulic fracturing operations. This new concept consists in creating over the volume of the fracture a layered proppant pack structure: The layers in contact with the fracture faces (the “External layers”) have a particle size distribution (PSD) selected to prevent the damaging fines coming from the formation to invade the proppant pack. And in the middle of the pack (the “Internal Layer”) a layer of larger proppant is placed to provide the fracture conductivity that is needed and whose PSD is selected so that it cannot be invaded by the particulates of the external layers.

In essence it is a "Double Layer Size Exclusion Process", the external layers stopping the damaging formation fines and the central conductivity layer being protected from the invasion of the external layers.

The very core of the invention is the technique used to create this layered structure which could never be achieved until now.

This process involves several steps.

First a “fine grained proppant” (hereafter also called “fine proppant” for simplicity), preferably but not necessarily “tacky”, is placed in the fracture created by a conventional hydraulic fracturing technique. Then the well is temporarily shut-in, optionally with some carefully controlled flow back or reverse flow so as to increase the rate of closure of the fracture upon the said first fine proppant, for a time sufficient for the said first proppant to be encroached/embedded into the walls of the fracture. Then the same said fracture is re-opened by resuming the pumping of a fracturing fluid transporting this time a much coarser proppant which is placed in the course of this operation in the “middle” of the width of the fracture, that is, placed between the two layers of fine proppant encroached or embedded into the fracture walls.

Terms such as “usual hydraulic fracturing technique”, “proppant”, “tacky”, “embedded”, “placement” (of the proppant), fracture faces are defined here-above and/or are part of the common knowledge of a skilled man.

DETAILED DESCRIPTION OF THE INVENTION

How to combat Formation Fines Generation, Invasion and Migration.

As discussed in the previous paragraph, formation fines generation, invasion and migration represent the key challenges in reservoirs such as shales, coal seams and more generally poorly consolidated reservoirs. These reservoirs are precisely those targeted by the industry in many parts of the world now that most good, easy reservoirs have been found and exploited.

In these reservoirs the industry is confronted to a difficult challenge:

On one hand, the industry would like to use a large highly conductive proppant so that the pack is more tolerant to a certain amount of fines and maintains a good enough conductivity. On the other hand, large proppants tend to cause even more destruction of the rock (smaller number of points of contact between the formations and the proppant particles generating very high point to point stresses) and facilitate fines invasion and migration because of their larger porosity. The higher initial conductivity achieved with larger proppants may be lost over time due to the invasion and migration of larger amounts of formation fines. The surface tackiness concept from Halliburton is certainly interesting since it does combat invasion and migration of fines but relying on this mechanism only is not sufficient. We need a stronger mechanism that will work in a large variety of situations and also in challenging in-situ conditions such as high reservoir temperature, high closure stress, cycling pressures etc. The various solutions developed by the industry over the years have been proven to have limited efficiency since all refrac operations lead to very significant production increases, more than what hydraulic fracture prediction models would predict.

As briefly mentioned above, an entirely new concept is needed to overcome the problem of formation fines invasion into the proppant pack, since the current concepts have reached their limit efficiency in the more challenging reservoirs that the industry has to deal nowadays.

Description of the new concept. The creation of a stable layered pack structure: the 2 steps fracturing process with intermediate shut-in and re-opening of the fracture.

This new concept is based on the creation of a layered proppant pack structure placed in the fracture with an innovative 2 steps fracturing process with intermediate shut-in and re-opening of the fracture. The process can be described as follows:

- First: creating the hydraulic fracture and placing in this said created fracture a fine grained proppant distributed over the full extent of the fracture or at least as much as possible of its full extent. The amount of fine grained
proppant placed in the fracture will be such that after shut-in it will be able to form on the entire surface of each face of the fracture, a layer of fine grained proppant with a minimum thickness representing at least twice the average PSD of the fine proppant.

- Second: shutting-in the well to let the fracture close and the confinement stress of the reservoir re-established so as to compress the fine proppant against the walls of the fracture and to result in a strong adhesion of the fine grained proppant against the walls of the fracture. A rate-controlled reverse flow or flow back can be initiated during shut-in and after the fracture has closed on the proppant to speed-up the process of re-establishing the full closure stress of the reservoir. This must be done following the well-known industry practices. Some embedment / encroachment and some limited rock destruction may take place at this stage but that will contribute to immobilize further the fine grained particulate material against the faces of the fracture.

This first step followed by the shut-in is in effect a "conditioning" of the fracture faces. The first fine particulate material is named here "fine proppant" though it is just as much a "conditioning agent" for the fracture faces. However, it is placed via an hydraulic fracturing technique exactly as a proppant would.

- Third: Re-opening the same hydraulic fracture using a conventional fracturing technique to place a "larger or much larger proppant" (equally called "coarse proppant" or "conductive proppant") in the middle of the fracture width and therefore between the layers of the fine proppant remaining in place against the walls of the fracture because of the strong interactions previously established during the shut-in, and acting as a "support" for the larger proppant, the said fine "support" proppant allowing the said larger proppant to ensure and retain a high conductivity for a long period of time. The thickness of the internal layer must be sufficient to provide the necessary conductivity. It should be at least 2 to 3 times the average particle size of the large proppant so that the pack can perform adequately.

[0083] Without to be tied by a theory, the Inventor and Applicant submit that the core of the invention is in the specific process to achieve the effective placement of these "External Layers" of the fine proppant and to maintain these layers in place during the sub-sequent steps of the operation and in particular while placing the "Internal Layer" of larger proppant so that these "external layers" can provide the to-date unknown function of "support" that is minimizing the destruction of the rock hence the amount of fines generated, screening out the fines and allowing the large proppant pack conductivity to be unaffected by any particulate material coming from the reservoir so as to preserve its high and effective level of conductivity for a long period of time.

[0084] The invention concerns a method of hydraulic fracturing oil and or gas wells in order to create a layered proppant pack structure alongside the faces of the fracture to prevent formation fines to damage the fracture conductivity over time characterized in that it comprises the process to place an external layer of fine grained proppant 5 against most of each of the surface of the fracture faces 2 AND in ensuring that the said layers remain in place during the subsequent steps of the process by a shut-in and optionally the previous use of a tacky agent.

[0085] By "most" it is meant that the external layers (5) deposited on each of the faces of the fracture cover the said faces to the maximum extent attainable by the current fracturing technologies. That is, the said fine grained proppant is transported by the said frac gel or fluid (20) to the extremity of the fracture, or close to, since it is known that it is not believed to be absolutely certain to reach the said extremities. The skilled man however (having strictly no way to know to what extent the proppant is transported inside the fracture) knows how to evaluate such things given the fine grained sized considered here, and the known frac fluid or gel, as well as usual consideration of viscosity, flowrate, pressure etc., which are routine to him, a skilled man is able to appreciate what "most" means. The inventor believes it can be as much as 80 to 90 % of the global surface of each face, with a transport deep into the fracture since it is a fine grained proppant.

[0086] By "most" it is also meant that the present invention covers most of the surface with fine grained proppant.

[0087] The invention essentially differ from the prior art in that it involves the process to place the external layer of fine grained proppant against most of the surface of the fracture faces AND in ensuring that they remain in place during the sub-sequent steps of the process by a shut-in and optionally the use of a tacky agent, what is called here a "support" function.

[0088] Keeping the fine grained proppant in place against the faces of the fracture while placing the larger proppant as the "Internal" layer is challenging and absolutely essential to the invention. It can be achieved very locally in conventional fracture operations when small particles pumped in the early stage of the fracturing treatment tend to accumulate opposite the zones of higher permeability of the reservoir (for example across the natural fractures). In fact this is the exact purpose of adding such material in the early stage of the operation: This is what is referred to, in the industry, as leak-off control. But to combat effectively formation fines, one needs this accumulation of leak-off control material all along the fracture faces in poorly consolidated reservoirs. Not just locally. On top of that even in the very localized areas where there is accumulation of fine particles in conventional operations, these particles tend to be quickly eroded and
pushed further away in the fracture during the placement of the proppant material. The prior art result was obviously a very limited coverage of the fracture walls, actually almost strictly limited to the zones of high leak-off. We submit that such a very limited coverage of the fracture faces can not be compared to our full coverage of the entire surface of the walls, including where there is no leak off.

[0089] This coverage over the full extent of the fracture faces is providing in fact a new function, a "support function of the large proppant pack", ensuring an exceptional conductivity over time.

[0090] These evident difficulties in ensuring the placement and stability of a layered proppant pack structure are possibly the reason why, to the best of the inventor's knowledge, no serious attempt has been initiated in that direction by lack of identified and credible solutions.

[0091] Maintaining in place these 2 layers of fine grained proppant against the walls of the fracture during the placement of the large proppant can be significantly improved by the use of tacky materials as introduced by Halliburton. And this can be achieved in different ways.

[0092] The first option consists in pumping a "tacky" material as part of the fracturing fluid pumped in the first step but ahead of the fine grained proppant, ie in the pad volume of the first step fracturing operation. This "tacky" compound or "tackiness-imparting compound" (hereafter referred to as "tacky") product will get absorbed on the faces of the fracture and penetrate into any porosity, cavity, microcavity and natural micro-fractures present in the reservoir. This tacky material placed on the faces of the fracture will improve the adhesion of the fine grained proppant in particular during the shut-in operation and when the closure stress of the reservoir is fully active onto this material.

[0093] Another option consists in directly pumping the fine grained proppant whose particles have been treated on part of their surface by a tacky compound or pumping simultaneously untreated fine proppant particles and a tacky-product-containing fracturing fluid. That way, the fracture faces and some particles become tacky or partially tacky during the pumping which again should favor the immobilization of the fine grained proppant during the shut-in and subsequent operations. The advantage of this option is that it can lead to the stabilization of several layers of fine particulate proppant. But it could be counter-productive to go too far in that direction. Using particles fully covered with tacky materials when pumped from surface may not be the optimum solution: there may be a tendency for such particles to form agglomerates and then prevent a good covering of the faces of the fractures. And the pumping of fully covered tacky particles could increase the rate of erosion of the fine gained proppant placed at the beginning of the placement, before the time closure stress is applied onto these particles.

[0094] By using tacky materials, we use both mechanical and chemical mechanisms to ensure a good adhesion of the fine grained proppant against the faces of the fracture.

[0095] It has to be noted that, after shut-in, the re-opening of the fracture to place the larger proppant will take place in the middle of the fine grained proppant pack because of the strong interactions that will have been created between this pack and the faces of the fracture, via the embedment and encroachment augmented in some cases by the presence of tacky material. So the large proppant material will naturally go in the middle of the fine grained proppant pack, exactly where we want it to go. Again the shut-in period is essential to create such strong interactions, mechanical (embedment and encroachment) and chemical (if tacky materials are present) because the closure will have exerted a high pressure onto the fine proppant.

Selection of the proppant types and size and volumes.

[0096] The type of proppant between sand, resin-coated sand or ceramic is mostly selected based on the confinement stress applied to the pack of proppant during production. Other important criteria are obviously the price and availability in the size desired. This selection is part of the overall hydraulic fracturing treatment design for which design and prediction software have been developed.

[0097] In very general terms, the most accepted guidelines lead to select good quality sand up to a closure pressure of 4,000 psi. Above that level resin-coated sands can be selected up to 6000 psi. But when closure pressure is higher, ceramic proppants are highly recommended.

[0098] The particle sizes distributions of the proppants in the layers are selected as follows:

The first step of the process is in selecting the particle size distribution (PSD) of the fine grained proppant constituting the external layers of the layered proppant pack. This is determined to prevent the invasion of the formation fines. These fines can be the grains of the sedimentary rock itself or can come from the breaking of these grains or from the mobilization of fines existing in the porosity of the rock. Based on the origin and particle size distribution of these fines, the PSD (Particle Size distribution) of the fine grained proppant is selected to prevent any invasion of these fines using the well-known Saucier's criteria. This criteria calls for a ratio of 6 maximum between the size of the fine grained proppant relative to the size of the formation fines present or generated during the fracturing treatment and subsequent application of closure stresses.
But any criteria can be used if it is the belief of the operator that the ratio of the PSD to prevent invasion of fine particulate materials into a larger particulate material pack is appropriate.

Once the PSD of the fine grained proppants is selected, the average PSD of the coarser proppants of the internal layer is selected using again the same ratio defined by Saucier: The average PSD of the coarser proppant of the internal layer must not be larger than 6 times the average PSD of the fine grained proppant of the external layers.

By combining these 2 ratios we observe that the "layered proppant pack structure" will be able to prevent the invasion in the internal layer of formation fines as small as 1/36th the average PSD of this layer. Formation fines smaller than that will be able to flow through the central layer without causing any damage.

This is in essence managing a "Double Layer Proppants Pack Structure" concept within the proppant pack.

The amount of fine grained proppant placed in the fracture will be such that after shut-in it will be able to form on the entire surface of each face of the fracture, a layer of fine grained proppant with a minimum thickness representing at least twice the average PSD of the fine proppant. The thickness of the internal layer must be sufficient to provide the necessary conductivity. It should be at least 2 to 3 times the average particle size of the large proppant so that the pack can perform adequately.

Possible associations of particulate materials:

The fine grained proppant for the external layers can be what the industry refers to as 100 mesh sand although it is in general a 50/140 mesh sand. In that case the proppant for the internal layer can be as large as a 12/20 sand and still meet the Saucier criteria. And obviously all the smaller most common proppant sizes such as 16/30, 20/40, 30/50, 40/70 can be used in conjunction with the 100 mesh fine grained proppant.

There is a trade-off between using the largest possible PSD for the large proppant for the internal layer and the smallest fine grained proppant for the external layers.

The largest possible PSD for the internal layer provides the highest conductivity in the proppant pack. However this may generate higher risk of premature screen-outs. And this determines also the smallest acceptable PSD for the fine material proppant.

At the other extreme of the range of possibilities, there are advantages in using the fine material as fine as possible. Better transport into the fracture and less sedimentation during the closure of the fracture. Hence a better coverage of the fracture faces. Less rock destruction, hence less formation fines. And possibly less erosion by the subsequent pumping of the large proppant.

The skilled man will be able to elaborate the best compromise based on the above, the common knowledge, and the below recommendations.

### Table: Possible associations of particulate materials

<table>
<thead>
<tr>
<th>“External” Layer Fine Proppant “Conditioning/Leak-off control Agent”</th>
<th>Average PSD</th>
<th>“Internal” Layer Larger Proppant</th>
<th>Conductivity Proppant</th>
</tr>
</thead>
<tbody>
<tr>
<td>100 mesh (or 50/140 mesh)</td>
<td>0,20</td>
<td>12/20 mesh proppant and smaller</td>
<td></td>
</tr>
<tr>
<td>100 to 200 mesh</td>
<td>0,11</td>
<td>20/40 mesh proppant and smaller</td>
<td></td>
</tr>
<tr>
<td>200 to 300 mesh</td>
<td>0,06</td>
<td>40/70 mesh proppant and smaller (US mesh series)</td>
<td></td>
</tr>
</tbody>
</table>

Selection of the fracturing fluids for each step. Detailed design.

Fracturing fluids selection is part of the common knowledge of the skilled man in the technique. Their composition and viscosity depend on the proppants they must properly carry into the fracture. As the proppant is lighter in density or smaller in size, the fracturing fluids can be less viscous down to what the industry refers to as "slick water" described in many publications and reference books. On the opposite, the transport of heavy, large proppant will require a very viscous cross-linked gel.

In all cases, sequence of fluids with varying properties are required, most notably the "pads" used to initiate the fracture.

Our inventive 2 steps approach is substantially different from a typical re-fracting operations: the present, inventive technique aims at minimizing the damage to the fracture conductivity over time once and for all. The first step does not aim at producing commercial quantities of hydrocarbons. The first step is specially designed to condition the faces of the fracture created in this step to optimize the performance of the second step of the fracturing treatment. Operating conditions between the 2 steps are normally very different. The first treatment aims at creating the fracture and placing a fine particulate material in it without necessarily creating a substantially conductive fracture. There is no need for high viscosity fluids in the said first step because sedimentation of fine particles is minimum. Hence no gel residue or very limited gel residue will remain in place. The second step is the placement of the large, conductive proppant in the fracture that has already been created. There is no need any more for substantial amount of leak-off material. It
has been put in place during the first step. Every variable is selected to maximize fracture conductivity as per the state of the art.

[0112] This “adaptation” is part of the state of the art and will not be uselessly duplicated here. This above concept of 2 steps (fracturing operation, shut in and closure, then reopening the fracture) described above was never even approached by the various industry practices discussed in the Prior Art as shown below by reviewing the various industry practices associated with hydraulic fracturing operations.

Fracturing Pre-treatments for data acquisition.

[0113] Pre-treatments to optimize actual fracturing treatments were introduced in the industry a long time ago. They were all, though, aiming at capturing data to optimize the design of the later fracturing treatment. They have become routine procedures in the industry under the names of “DataFrac”, “MiniFrac”, Diagnostic Fracture Injection Test (DFIT) or others. They are pre-treatments aiming at determining fracturing pressures, leak-off mechanisms and fluid-loss coefficients, spurt losses, closure pressures and generally all parameters useful in running fracturing models and optimizing fracturing operations. This is well described in US Patent 5,305,211: Method for determining fluid-loss coefficient and spurt loss. It is also discussed in the first paper of the Conductivity Endurance brochure referred at the beginning of this memo: “Propping up production”.

[0114] These pre-treatments are done some time ahead of the main fracturing treatment so that the acquired data can be fed into the fracturing software to optimize the design of the treatment.

[0115] So such DataFrac or MiniFrac pre-treatments can be considered as the first step of a 2 step-approach but not at all for the same purpose and the treatment characteristics of the first step are very substantially different from those that we need to address the problems of formation fines: They are done usually with the actual frac fluid used to carry the proppant in the real fracturing treatment but no proppant are used in such tests. The amount of fluid and duration of operations are kept to the minimum required to acquire the data, usually a small proportion of the volume and time used for the “real” frac. Minimizing the amount of fluids in these data acquisition fracturing pre-treatments is important to minimize the shut-in time. In fact, shut-in may not be sufficient in low permeability tests. Fluid flow-backs may have to be initiated after the initial shut-in when leak-off is too slow to observe fracture closure in a reasonable amount of time.

[0116] The wording of “pre-treatment” must not mislead the reader: they are not actual pre-treatments but rather “testing preliminary operations” absolutely NOT aimed at being part of the following treatment itself.

[0117] To the contrary, the 1st step treatment described in this invention IS designed to place fine particulate material in the formation as an integral part of the global treatment of the invention.

[0118] An interesting point is that it can also be used to collect all the data required to optimize the 2nd step fracturing operation, BUT this data collection is not part of the concept, it is a “collateral advantage”, and must not be confused with the “data collection preliminary steps” of the prior art. For the same kind of reasons, the prior art could not suggest the multi-step treatment of the invention, since the “teaching” of the prior art was to first collect data, then apply a PRIOR ART PROCESS not using or not “following” the preliminary “collection step” as part of a global multi-steps process.

PrePack Fracturing Techniques

[0119] These are successive pumping STAGES in a single fracturing treatment.

[0120] This technique (described in the SPE paper 5643: Prepack technique using fine sand improves results of fracturing and fracture acidizing treatments by B.D. Miller and P.A. Warembourg) has become a very standard practice in hydraulic fracturing operations. It consists in pumping fine particulate material such as 100 mesh sand in a pre-pack stage ahead of the main stages of the fracturing treatments. It is one stage of a multiple stages single fracturing treatment. The pumping operation is not stopped between stages as the fracture needs to remain open for the pumping of the following stages. This technique is especially beneficial to combat fluid losses into natural fractures and high permeability zones of the formation. It is mostly a leak-off control technique.

[0121] This leak-off control material creates a “cake” opposite the most permeable parts of the fracture face and could later act as a filter. However the pumping of the main proppant laden fracturing fluid can easily and quickly displace this small concentration of fine particles and most of the benefit in terms of filtering out formation fines is usually lost. In fact the amount of leak-off material added to the early stage of the fracturing is determined by the amount of leak-off expected in the reservoir. Highly natural fractured reservoirs usually command higher concentrations of leak-off material. Its impact on the treatment is expected only during the pumping of the fluids, specially the proppant laden fluids to avoid early screen-out.

[0122] These “cakes” of fine sand only take place across the zones of high leak-off. Over the vast majority of the surfaces of the fractures, there is no accumulation of leak-off material whatsoever.
Other Multi-stage Fracturing Treatments.

There are multiple approaches to hydraulic fracturing including multiple stages on top and above the pre-pack technique described above.

The PCT/Patent application (USA, European and others) referenced below is particularly related to the present invention in the fact that the various stages of pumping aim at creating a specific structure within the proppant pack to maximize its conductivity as described in the summary below.


Invention summary.

The invention provides economically effective methods for hydraulic fracturing a subterranean formation that ensure improvement of the hydraulic fracture conductivity because of forming strong proppant clusters uniformly placed in the fracture throughout its length. One of these methods comprises: a first stage that involves injection into a borehole of fracturing fluid containing thickeners to create a fracture in the formation; and a second stage that involves periodic introduction of proppant into the injected fracturing fluid to supply the proppant into a created fracture, to form proppant clusters within the fracture to prevent fracture closure and channels for flowing formation fluids between the clusters, wherein the second stage or its sub-stages involve additional introduction of either a reinforcing or consolidation material or both, thus increasing the strength of the proppant clusters formed into the fracture fluid. Another method comprises: a first stage that involves injection of said fracturing fluid into a borehole, and a second stage that involves introduction of proppant into the injected fracturing fluid and further, involving periodic introduction of an agent into the fracturing fluid to provide formation of proppant clusters in the created fracture and channels for flowing formation fluids. Still another method comprises: a first stage that involves injection of a fracturing fluid into a borehole; a second stage that involves continuous introduction of a proppant into the injected fracturing fluid, and a third stage that involves injection of a lower-viscosity, in comparison with fracturing, fluid into the fracturing fluid, the lower-viscosity fluid, owing to the difference in viscosity compared to the fracturing fluid, penetrating into the fracturing fluid in the form of intrusions that divide the proppant into discrete clusters to form channels between them through which formation fluids to pass.

See reference below: http://www.faqs.org/patents/app/20090044945

Again this document does not mention at all any shut-in of the formation between stages to contribute to the creation of a particular proppant pack structure. In addition, the structure that is proposed is subject to intense crushing since only part of the fracture is supported by the clusters of proppants. These clusters are therefore submitted to closure stress far superior to the average confinement stress of the formation since it applies only to a portion of the fracture.

Re-fracturing operations.

Re-fracturing operations consist in fracturing again a reservoir that has been fractured before and put in production until the level of production is much lower than what is expected from the reservoir. There are many reasons that can cause the hydraulically fractured reservoir not to perform as expected over time. The conditions of the first fracturing treatment may not have been adequate to start with. Or the conductivity of the fracture may have been impaired over time. Whatever the reason operators tend to re-fracture such wells, in the same interval in the hope to revive the well and get its production back to where it is supposed to be. Re-fracturing consists then in placing new proppants in the previously fractured wells to create a larger proppant pack. This can be done using exactly the same operating conditions as for the first fracturing. Or it can be done with slightly different operating conditions: different amount and composition of fracturing fluids, different amount, type and size of proppants. For example, operators may decide to use ceramic proppants in place of sand used in the first treatment. However in no case there has been any attempt to try to optimize the second treatment based on what had been pumped in the first place.

What makes our 2 steps fracturing process concept attractive, is precisely the fact that re-fracturing operations are often successful and indeed lead to a significant increase in well productivity, indicating that in many cases the fracture conductivity has indeed been impaired during production. This "merely" larger proppant pack produced by the re-fracturing operations cannot be compared to the synergistic layered proppant pack concept described in this invention.

It is interesting to note that some re-fracturing operations lead to production declines similar to those observed after the first treatment, indicating that the fracture conductivity problem over time has not been resolved. Wells then need to be re-fractured every time the fracture conductivity is again substantially reduced.

There is no synergy between the above described re-fracturing operations: The initial frac is designed to be
The small particle size distribution of this particulate material facilitates its transport into the fracture which can be
100 mesh sand, is mixed with the fracturing fluid, injected and placed in the fracture as the "fine grained proppant" (5).

The formation is hydraulically fractured in accordance with the method of the present invention. When fracturing
certain types of formations and placing proppants in the fracture, formation fines (10) can be generated as a result of
the mechanical interactions of the proppant with the formation under confinement stress. Alternatively, or simultaneously
with the mechanism just described, these formation fines can be present in the formation from before the fracturing
treatment and made mobile and movable as a result of the chemical interactions between the formation and the fracturing
fluids. Some of these fines can be forced mechanically to penetrate the fracture under the confinement stress. They
can also be entrained by the formation fluid flowing into the fracture when the well is placed in production. In most cases
both mechanisms are active and the fracture can be dramatically invaded during the fracturing or after the well is placed
in production.

A brief description of the most preferred fracturing treatment of the invention will now be set forth, following
which a more detailed description of field fracturing operation carrying out such a fracturing treatment will also be set forth.

Initially, a fracture fluid containing a tackifying agent is injected through the well casing perforations into the
formation or "matrix" M, as shown in FIG. 1 or 4 but with NO PROPPANT, at a pressure and pumping rate that will cause
the formation to crack, creating what is referred to as hydraulic fractures. Such a tackifying agent will cover the faces F
of the fractures as they are created while the continuous pumping of the fracturing fluid propagates the fracture into the
formation.

In a second stage of the same continuous pumping step, Fig. 4, a small mesh particulate material, such as
100 mesh sand, is mixed with the fracturing fluid, injected and placed in the fracture as the "fine grained proppant" (5). The
small particle size distribution of this particulate material facilitates its transport into the fracture which can be
achieved with low viscosity fracturing fluids such as linear polymers solutions or even slick water. The amount of fine material pumped during this step is such that at the end of this step the small particulate material is present over the full extent of the fracture in quantities that will allow this material to cover the entire surface of the fracture faces.

This fine particulate material is, in a preferred embodiment, partially covered with a tacky agent. The covering with the tacky agent can be done before the pumping or during the pumping: the tacky agent and the fine particulate material are pumped together and during the transfer down-hole the tacky material adheres to the fine particulate material and covers from 20 to 80% of its total surface area.

In a third stage of the invention, Fig. 5, "SHUT-IN" stage, the pumping is stopped and the pressure within the fracture let decrease as a result of the filtration of the fracturing fluid into the formation. The monitoring of the pressure at the wellhead versus time allows to determine the time when the fracture has closed over the small grain particle size material. The well continues to be maintained closed after the fracture closure until the formation closure stress is applied to the particulate material. This is again monitored via the surface pressure at the wellhead, if this natural pressure decline process is too much time consuming, the well can be opened to let some fracturing fluids to be produced back at a production rate lower than 0.001 bopm per perforation to minimize the amount of fine particulate material produced back into the well-bore. But the opening of the well to permit some flowback can only be initiated once the fracture has closed on the fine particulate material as indicated by the record of the wellhead pressure versus time. The formation closure stress when it is re-established at the end of the shut-in imposes a very strong interaction between the particulate material and the faces of the fracture first mechanically though embedment and then chemically because of the presence of the tacky material over the surface of the fracture walls, within the porosity of the formation area close to the fracture faces and on part of the surface of the fine particulate material.

In a fourth stage of the invention, "re-opening of the fracture", Fig. 6, the pumping is then re-started to re-open the previously created fracture. First a fracturing fluid without solid material is pumped so that the fracture can be re-opened without taking the risk of a screen-out (volume usually referred to the industry as the PAD volume). When this is done and without interrupting the pumping a fracturing fluid with the larger conductive proppant (30) is placed into the fracture. Because of the larger average particle size distribution of this proppant (30) compared to the fine proppant (5) pumped in the first step a more viscous fracturing fluid is used, either a linear polymer gel of higher concentration or even a cross-linked polymer gel. This larger proppant (30) typically a 20/40 mesh material --- is placed over the full extent of the fracture. This large propping material can also be mixed with a tacky agent either before the pumping or during the pumping although this is not a preferred practice. A cross-sectional end view of the reservoir fracture is shown in Fig. 6 and on the Fig. 7 showing the production. A 20/40 mesh sand is used in the case described here but any size and type of proppant can be used as long as we maintain the right ratio of Average Particle size Distribution (Average PSD) . Resin-coated materials can also be used either as a tail-in or for the entire volume of large proppant (30) to avoid proppant flow back during the production operations. Once the placement of the large proppant is completed, the well is closed to allow for the pressure in the fracture to decline in the same manner as it was done during shut-in, again with a well controlled flow-back to accelerate the pressure decline if necessary and apply the formation closure stress onto the larger proppant and from there onto the fine material that will be definitelly immobilized as a layer between the faces and the pack of larger proppant. The 100 mesh particulate material layer (5) up against the fracture face and the 20/40 particulate material layer (30) will block formation fines (10) to invade the coarse proppant and maintain its conductivity over the life of the well. Other sizes of both materials can be used as long as the correct ratio of average PSD (particle size) is maintained. This is the final step of the process covered by this invention. The fracturing treatment of the invention is now completed and oil or gas production may now be carried out with high fracture conductivity over time.

**DETAILED JOB DESIGNS INCORPORATING THE PRESENT INVENTION.**

Having briefly described the hydraulic fracturing method of the invention, a more detailed description of two field operation designs employed for carrying out such method will now be set forth.

In each treatment we have defines Steps and within each step, Phases.

**EXAMPLE 1. Small Treatment. Shallow formation. Tacky agent pumped in both phases of Step 1 but not afterward.**

In this first example, phase 1 of step 1 consists in pumping 2,000 gallons of 15% acetic acid to facilitate the penetration of the fluid into the formation and transmit the fluid pressure into the formation to initiate the creation of the fracture. Then 5,000 gallons of 20 lb/1000gal of HPG polymer solution containing 50lb/1000gal of a tacky material is injected into the reservoir; Then and without interrupting the pumping operation, 10,000 gallons of the same fracturing fluid mixed with concentrations of 100 mesh sand increasing from 2lb/gal up to 6 lb/gal mixed with 2% of active tacky material by weight of particulate material are pumped in order to place the fine particulate material over the full extent of the fracture. All fluids in this step 1 are pumped at a rate of 20 barrels per minute.

Then the well is shut in and the surface pressure at the wellhead monitored to determine the time when the...
fracture closes. The well is maintained close for another 30 minutes and then slowly reopened. The rate of fluid flow back is limited to a maximum of 0.001 bpm per perforation to avoid any production back of particulate material.

[0154] In the next step, the fracture is re-opened and the coarse proppant placed into the fracture. This is done by pumping in a first phase 5,000 gals of fracturing fluid containing 40lb/1000gal of HPG and then in the second phase but without interruption of the pumping 12,000 gallons of fracturing fluid containing 40lb/1000gal of HPG, 1lb/1000gal of cross-linker and concentrations of 20-40 mesh proppant increasing from 2lb/gal up to 8lb/gal for a total average concentration of 5lb/gal. During the final 500 gallons of fluid injection, the cross-linker was eliminated and the pumping rate reduced to 5 barrels per minute.

[0155] Following the fracturing treatment the well is opened with the same precautions that were taken for the shut-in. First the well is maintained closed until the fracture closure is detected by monitoring the surface pressure at the wellhead. The well is maintained close for another 30 minutes and then the surface valve opened and reverse flow allowed at a controlled flow rate of 0.001 bpm per perforation to minimize proppant flow-back.

[0156] This is summarized below:

Step 1: Creating the fracture and placing the fine particulate material.

Phase 1: Initiating the fracture and placing the tacky agent on the faces of the fracture and in the areas of the formation closed to the fracture faces. Pumping:

- 2000 gals of 15% acetic acid
- 5000 gals of fracturing fluid containing
  - 20 lb/1000gal of HPG (Hydroxypropylguar)
  - 50 lb/1000gal of active tacky material

Phase 2: Propagating the fracture and placing the fine particulate material in it

- 10000 gals of fracturing fluid
  - 20 lb/1000 gal of HPG
  - 4 lb/gal of 100 mesh sand increasing from 2 lb/gal up to 6 lb/gal in increments of 2000 gals
  - Increasing concentrations of active tacky agent in order to always have 2% of active tacky material by weight of 100 mesh sand

Step 2: Shut in. Stop the pumping.
Wait for the fracture closure as indicated by the surface well pressure response. Allow for reverse flow at a rate of 0.001 bbl/mn per perforation for 60 minute minimum

Step 3: Filling the fracture with the coarse proppant.

Phase 1: Re-opening the fracture. Pumping:

- 5000 gals of fracturing fluid
  - 40lb/1000 gal of HPG

Phase 2: Placing the proppant

- 12,000 Gals of fracturing fluid
  - 40lb/1000gal of HPG
  - 1lb/1000gal of cross-linker
  - From 2 to 8 lbs/gal of 20-40 mesh proppant, average concentration 5 lbs/gal

Phase 3: Flush. Pushing the proppant away from the well-bore

- 1,500 Gals of slick water

Phase 4: Shutting down the well. Wait for the fracture closure as indicated by the well surface pressure response.
Wait for another 30 minutes and start production.
Note: All fluids contain the usual amount of bactericides, surfactants and gel breakers used in fracturing operations. All fluids pumped at 20 bpm.

**EXAMPLE 2. Large Treatment. Deeper formation. Tacky agent mostly pumped in phase 1 of step 1**

Step 1: Creating the fracture and placing the fine particulate material.

Phase 1: Initiating the fracture and placing the tacky agent on the faces of the fracture and in the areas of the formation closed to the fracture faces. Pumping:

- 5000 gals of 15% acetic acid
- 50000 gals of fracturing fluid containing
  - 40 lb/1000gal of HPG (Hydroxypropylguar)
  - 50 lb/1000gal of active tacky material

Phase 2: Propagating the fracture and placing the fine particulate material in it

- 100000 gals of fracturing fluid
  - 40 lb/1000 gal of HPG
  - 4 lb/gal of 100 mesh sand increasing from 2 lb/gal up to 6 lb/gal
  - 20 lbs of active tacky agent per 1000 gal of fracturing fluid (2% of active tacky material by weight of 100 mesh sand)

Step 2: Shut in. Stop the pumping.
Wait for the fracture closure as indicated by the surface well pressure response.
Allow for reverse flow at a rate of 0.001 bbl/mn per perforation for 60 minute minimum

Step 3: Filling the fracture with the coarse proppant.

Phase 1: Re-opening the fracture. Pumping:

- 50000 gals of fracturing fluid
  - 40lb/1000 gal of HPG
  - 1lb/1000gal of cross-linker

Phase 2: Placing the proppant

- 120.000 Gals of fracturing fluid
  - 40lb/1000gal of HPG
  - 1lb/1000gal of cross-linker
  - From 2 to 8 lbs/gal of 20-40 mesh proppant, average concentration 5 lbs/gal

- Flush. Pushing the proppant away from the well-bore 5.000 Gals of slick water

Phase 3: Shutting down the well. Wait for the fracture closure as indicated by the well surface pressure response.
Wait for another 60 minutes and start production.
Note: All fluids contain the usual amount of bactericides, surfactants and gel breakers used in fracturing operations. All fluids pumped at 40bpm
Claims

1. Method of hydraulic fracturing oil and or gas wells to create a layered proppant pack structure alongside the faces of the fracture to prevent formation fines (10) to damage the fracture conductivity over time characterized in that it comprises the process to place an external layer of fine grained proppant (5) against most of each of the surface of the fracture faces 2 AND in ensuring that the said layers remain in place during the subsequent steps of the process by a shut-in and optionally the previous use of a tacky agent.

2. Method according to claim 1 characterized in that it comprises several distinct steps:
   i) pumping at a fracturing rate a fracturing gel or fluid thus creating a hydraulic fracture and transporting into the so opened fracture a “fine grained proppant” (5) (equally called here “fine proppant” or “fine particulate material”).
   ii) Shutting-in the well to let the fracture close and the confinement stress of the reservoir to be re-established compressing the fine proppant (5) against the walls of the fracture and resulting in some encroachment and embedment of the fine proppant into the fracture walls.
   iii) Re-opening the same hydraulic fracture using a conventional fracturing technique to place a larger proppant or “coarse proppant” (30) in the middle of the fracture width and therefore between the layers of fine proppant remaining in place against the walls of the fracture as a result of the strong interactions with the fracture walls that were previously established during the shut-in, and acting as a “support” for the larger proppant, the said fine “support” proppant allowing the said larger proppant to ensure and retain a high conductivity for a long period of time.

3. Method according to claim 2, characterized in that in step i) the first frac fluid or gel pumped to initiate and propagate the fracture contains a tackifier agent that will mostly adhere to the walls of the fracture followed by an identical or different frac fluid or gel not containing a tackifier but carrying a fine grained proppant having not been treated with a tackifier.

4. Method according to claim 2 characterized in that in step i) the first frac fluid or gel pumped to initiate and propagate the fracture does not contain a tackifier agent but is followed by an identical or different frac fluid or gel carrying a fine grained proppant that has been treated previously with a tackifier agent on at least a portion of each fine grained proppant particle either before pumping or during the pumping operation by incorporating the tackifying agent in the fracturing fluid.

5. Method according to claim 2 characterized in that in step i) the first frac fluid or gel consists in a fluid or gel contains a tackifier agent and is followed followed by an identical or different frac fluid or gel carrying a fine grained proppant that has been treated previously with a tackifier agent on at least a portion of each fine grained proppant particle either before pumping or during the pumping operation by incorporating the tackifying agent in the fracturing fluid.

6. Method according to any one of claims 1 to 5 characterized in that during the shut-in operation but after the fracture has closed on the fine grained proppant there is some reverse flow or flow back to accelerate the decrease of the pressure in the fracture so that the full closure stress of the reservoir is re-established against the fine grained proppant.

7. Method according to any one of claims 1 to 6 characterized in that the ratio of average particle sizes between the fine grained support proppant and the larger conductive proppant is set at a maximum value of 6 but can be set at any value lower than 6.

8. Method according any one of claims 1 to 6 characterized in that the ratio of average particle sizes between the fine grained support proppant and the larger conductive proppant is set at a maximum value of 8 but can be set at any value lower than 8.

9. Method according any one of claims 1 to 8 characterized in that the amount of fine grained proppant placed in the fracture will be such that after shut-in it will be able to form on the entire surface of each face of the fracture, a layer of fine grained proppant with a minimum thickness representing at least twice the average particle size of the fine proppant.

10. Method according any one of claims 1 to 9 characterized in that the thickness of the internal layer must be at least 2 to 3 times the average particle size of the large proppant (30) so that the pack can perform adequately.
FIG. 2
PRIOR ART and THEORY
Fracture closure. Partial rock destruction at the walls of the fracture. Generation of Formation Fines

- Formation fines from crushed formation: 40
- Formation fines: 10
- Proppant fines: 50
- Frac gel or fluid: 20
- Large proppant: 30
FIG. 3
PRIOR ART and THEORY
Well in production. Migration of fines

Formation fines from crushed formation
Formation fines
Proppant fines
Frac gel or fluid
Large proppant
FIG. 4

INVENTION. Pumping of small proppant
Partial destruction of the rock at the fracture faces.

Invention – Shut-in.
FIG. 7
Invention – Fracture Closure.

- Formation fines from crushed formation 40
- Formation fines 10
- Proppant fines 50
- Frac gel or fluid 20
- Large proppant 30
- Small proppant 5
FIG. 8  Invention - Well in production.
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<th>Citation of document with indication, where appropriate, of relevant passages</th>
<th>Relevant to claim</th>
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