INCREASE PRODUCTION BY USING A SILT-SUSPENDING ACID ADDITIVE

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ABSTRACT

In the reaction of formation rock with acid, as in a matrix acidizing treatment, varying quantities of insoluble fines are released or otherwise dislocated by the flow. Also, normal reservoir flow can break or dislodge fragile clays and minerals present on the pore linings. If allowed to settle and accumulate, these fines have the capability of plugging pore throats when disturbed in mass upon the return flow of the treatment and formation fluids. The addition of a silt-suspending additive to the acid used for treatment will prevent this accumulation by keeping the fines distributed in this fluid, thus preventing plugging while removing them from the formation.

A silt-suspending system that uses an electrostatic repulsion approach to fine suspension is discussed. Laboratory work describes the system's properties in relation to oil reservoirs and field data shows the system's usefulness. This treatment has been sucessfully used in well workovers to remove existing clays, fines, and precipitated solids. Production data on this aspect is presented.

INTRODUCTION

Matrix acidizing sandstone for the removal of silts and fines is a commonly practiced completion and workover treatment.[1-3] In the removal of these solids, surfactants and acid blends have been tested in many areas. Due to the fact that no area is exactly the same as another, no single additive is universally applicable. By selectively blending surfactants, it is possible to obtain a mixture with more universal properties. The areas where field testing is complete are in the Burbank formation, Osage County, Oklahoma.

Because of the extreme reservoir pressure depletion in these isolated areas, injection of water and polymer fluids are being tested. The pilot test of these injection projects are producing good results in most cases. The injection and movement of these fluids are closely monitored. Research in fluids, fluid compatibilities, additives, and core studies (X-ray diffraction, and scanning electron microscope) is well documented. The reporting and collection of this data produces a case for study where more data than usual is available.[4-6]

Production in several areas in recent years dropped below economical production levels. Because of the injection projects, economical justification for additional, larger volume acid stimulation was not possible. A small volume clean-up acid treatment was discussed.

EXISTING CONDITIONS

Production for two leases was reviewed and was found to be at a very low rate for both leases. (Table 1).

Additional tests on solid content and fluid compatibilities were conducted. The solids consisted of iron precipitates, silts, fines and traces of calcium sulfate crystals. The majority of these solids, sampled from the wellbore, were attributed to movement of fluids, both produced formation fluids and produced injection fluids. Reanalyzing injection and produced fluids indicated the produced water to be largely injection water. The solids existing in the wellbore were combinations of the formation silts and possible precipitates from formation/injection water. Because produced water is used as injection water, incompatibility of fluids was ruled out as a major problem.

The existence of calcium sulfate crystals in very low percentages indicates that the precipitation of these crystals in the wellbore is due to the pressure differential created as the fluid is produced and is not due to incompatible fluids. It can be proposed that the fluids were not completely compatible with the formation because the saturation point for the existing solubles continually varies with pressure and temperature. This fact accounts for the slightly lower solids content of injection water compared to produced water.

THEORIES ON DECLINING PRODUCTION

The decline of production is due primarily to depletion of the reservoir. The areas where the silt-suspending acid treatments are in progress are estimated to have 30 percent oil in place.

The excessive decline in productivity is due to a reduction in permeability near the wellbore. This is thought to be attributed to reprecipitation of salts and accumulation of naturally occurring solid fine particles. These solids have migrated in the direction of production to restrict permeability. According to Gruesbeck and Collins, entrainment and redeposition of naturally occurring particles in porous media has been suggested as a mechanism leading to abnormal decline in productivity of producing wells. This phenomena has been tested with core studies and solids identification.[7] Water and oil transport these solids until rate of fluid movement or restrictions force these solids out of the fluids.[8]

The formation permeability acts as a filter removing the soilds which are too large in diameter to move through. Because of the crystal structure of some salts and clays, wedging can also take place. The concentration of silts and fines present in the formation increases near the wellbore. There is a large percentage of clays present initially in the pores. With the addition of transported clay, where injection projects exist, the pore throats can become totally blocked.

Other types of formation damage are possible because these wells have been acidized and/or fractured in the past. These types of damage vary greatly from clay damage to residue of treatment fluids deposited on the formation face. The types of damage that apply to acidizing are covered, in brief, in the sections to follow. The major objective is to prevent any further damage, and to remove pore blockage and soluble precipitates where possible.

Iron complexes can be considered separately in formation damage due to their varying solubility in hydrochloric acid and formation water. Iron chlorites are present in most sandstone formations. Cores taken from new wells in the areas of study showed a clay known as chamosite (an iron-containing chlorite), which is widely distributed as a coating covering about 70 percent of the sand surface. As discussed by Holcomb and Hunt, iron chlorite-type clays must be stabilized to avoid precipitation of iron hydroxide.[9] This precipitate can do costly damage and reduce permeability greatly.

CONSIDERATION FOR TREATMENT DESIGNS

For economic reasons, the size of clean-up and matrix acidizing treatments in the areas being tested were limited in size. Stimulation with a large volume of acid could also create channels to the water zones and increase the volume of produced water. In fields where low bottom hole pressure was characteristic, large volumes of acid also tended to remain in the formation an adequate length of time to spend. With the pH increase, precipitates began to form and were deposited back on the formation. This might have cancelled any benefits derived from the dissolving of the acid-soluble fines initially present.[10]

Formation damage, as already mentioned, varies greatly, and all cases should be taken into consideration. The existence of iron compounds in the solids recovered from the wellbore represents a major factor related to the production decline. To eliminate the formation damage caused by the precipitation of iron compounds, a chelating agent should be incorporated in the design. As Holcomb and Hunt stated, the majority of the iron complexes that are soluble are capable of reprecipitation. The lower pH acts to restrict precipitation; however, the factor of potential iron precipitation is sufficient evidence for using some form of organic chelation method.[9-11]

With the movement of treating fluid in the opposite direction of production, a large quantity of solids will be disturbed, and migration of these fines should be considered.[11-13] In flow, fluid movement in and out of the formation can create damage.[13] This migration blockage can be treated by surfactants to promote the removal of released fines in suspension. The existing fines that have been relocated by the flow of production must also be considered. These fines are less difficult to treat because, in some cases, they are acid soluble; and in most instances they are influenced favorably by fluid movement in the flowback after a treatment. The solids which are insoluble can, to a large degree, be suspended and removed from the formation.

The use of a surfactant to aid in fluid return upon treatment completion is recommended. The rapid and complete return of partially spent acid is necessary to remove the soilds suspended in the solution. The ability to suspend particles is nonproductive unless the return of these particles is possible. Maintaining low surface tension/interfacial tension with a surfactant during the treatment, and throughout load recovery, is an efficient mechanism. This is true for the permeability improvement by the hydrochloric acid system, as well as for overcoming water saturation and imbibition effects for additional permeability improvement and load recovery.

The use of alternate systems, such as gelled systems, were also considered as a possible treatment. Generally, a gelling agent increases the viscosity of the hydrochloric acid solution, which enables the particulate matter (fines) to remain suspended, providing better clean-up of the particles. There are, however, disadvantages in a gelled acid system due to the present lack of a residue-free gelling agent, which will produce sufficient viscosity for a period of time at a given temperature.

Two basic types of polymeric material that are normally used to gel the acid are polysaccharides (xanthum gum, guar) and cellulose derivatives (hydroxyethyl cellulose, hydroxpropyl cellulose). Additional synthetic polymers, such as polyacrylates, polyacrylamides, polyvinyl alcohol, polyvinyl pyrollidone, etc., are used, or have been used in the past, for gelling hydrochloric acid. Polysaccharides provide an effective gel, but they are unstable in strong acids. At concentrations of 15 percent or greater hydrochloric and at temperatures exceeding 37.8°C. (100°F.) to 65.6°C. (150°F.), polysaccharides are ineffective viscosifers. Once a satisfactory gel system is obtained, it is usually difficult to break the gel due to hydrolytic stability of most synthetic polymers.[14]

As McDaniel and Lacey pointed out, all water-soluble polymers currently being used as viscosifers contain some residue; the amount of residue depends on the choice of polymer and its concentration. The influence of these residues on production is dependent on the particular well. It is important to note, that gelling agents overcoming these disadvantages have been developed and are in the research stages of field application. With the given disadvantages, it was necessary to develop an additive which incorporated a non-gelled system and a low surface tension/interfacial tension system.

DEVELOPMENTAL RESEARCH AND TESTING

Research was conducted to develop an additive or combination of additives that would impart in hydrochloric acid the ability to suspend solids during a matrix acidizing treatment. To arrive at the ideal system, a large number of additives and combinations of these additives were tested and recorded according to their suspending ability. This was done by exposing the acid-containing materials to bentonite clay. The clay was used in two forms in two different tests. The first was in a dry form, and the second was in a 6 percent slurry. All tests were thoroughly agitated and allowed to set in a static state for a period of time. The ability to suspend the clay was rated visually with the aid of a hand lens.

The best system was found to be a combination of two quaternary amines, a sequestering agent, and an acid corrosion inhibitor. In the dry bentonite tests, this system kept fine clay particles dispersed and suspended for more than 20 hours. The bentonite slurry became uniformly dispersed and suspended in the acid.

The surfactants, which are cationic, function by altering the surface properties of the liquid and fine solids present in the acid solution. The insoluble fines, contacted by the acid, are kept in suspension by electrostatic repulsion. Due to the interaction of the surfactants and the clay surfaces, the surfactants are molecularly absorbed on to these insoluble particle surfaces, thus repressing clay surface interactions.[1,14] The presence of the organic acid probably aids in neutralizing attractive forces and keeps the system dispersed and deflocculated, thus keeping fines in suspension. The additive also serves as a sequestering agent for the iron in solution.

The first tests conducted on the system were to determine the wetting tendencies of the system. These tests were based on the "API Recommended Practices for Laboratory testing of Surface Active Agents" API, RP 42, 1977. Briefly, this procedure consisted of soaking sand (20/40-Mesh Brady sand) in the acid system to be tested. After 30 min. the liquid solution was decanted into another vessel leaving the sand. Dyed, filtered kerosene was then carefully layered on top of the aqueous fluid. The treated sand was then allowed to fall through the dyed kerosene and aqueous phases. The action of dispersing of clumping in the two phases was observed, the system was found to allow the sand to disperse in the oil phase, oil-wetting the sand.

As mentioned previously, characteristics other than silt-suspending properties must also be considered in the design of an acid for oil well treatment. Tests were continued on the silt-suspending system to determine its effectiveness in dealing with these other important characteristics.

Surface Tension Determination

The effect of the system's surfactants on surface tension were to be determined next. Using a DuNouy surface tensiometer, it was determined that the surface tension of the acid system was 28.0 dynes/cm at 24.4°C. (76°F.) and 22.7 dynes/cm at 96.1°C. (205°F.). This indicated a surface tension reduction of 55 percent when compared to untreated hydrochloric acid of the same concentration, which possessed a surface tension of 61.9 dynes/cm at 24.4°C. (76°F.).

Core Flow Analysis

The system's effect on flow permeability was determined using core flow analysis. A core of Brea Sandstone was flowed with a two-percent potassium chloride (KCl) solution in the direction labeled as the production direction to determine its initial permeability (K_1). The core was then damaged by flowing a bentonite clay slurry in the opposite direction (injection) until flow was notably reduced. The core was then treated with the acid system flowing in the injection direction.

Finally, the permeability of the core after treatment (K_2) was determined by flowing a 2 percent KCl solution in the production direction. Using the Darcy formula to calculate permeability, the initial permeability (K_1) was found to equal to 388 md, and the final permeability (K_2) was equal to 409 md in this test. This yielded a permeability ratio (K_2/K_1) of 1.05 or an increase in permeability of five percent due to the tested treatment.

Non-Emulsification Test

An important consideration in designing an acid treatment is the compatibility of the acid with formation oil. Additives (surfactants) are usually necessary to prevent acid/oil emulsions from forming during the acid treatment. The experimental system has been tested using the standard acid/oil compatibility tests conducted in the laboratory. Various oils from several areas were tested with the experimental system while they were in the lab. Also, any acid treatment calling for the use of this system has had a compatibility test conducted using the oil present in the zone to be treated. In all cases tested, complete breaks of any emulsion, created by high-speed mixing, were achieved in less than 10 min., and usually in less than 3 min. This indicated the system has very good non-emulsification properties.

Research Conclusion

After this testing, the silt-suspending system was deemed to display the following properties in the laboratory:

1. Excellent insoluble fine suspension for the removal from the well for better cleanup.
2. Low surface tension for better penetration and non-emulsification tendencies.
3. A sequestering agent to prevent the formation of iron precipitates.
4. Characteristics that prevent clay swelling in water-sensitive formations.
5. A corrosion inhibitor to prevent acid corrosion of tubular and other downhole equipment.

FIELD APPLICATION AND RESULTS

These treatments were designed to use 1000 to 1200 gal of 15-percent hydrochloric acid with silt-suspending acid additives. In the first and second cases, additional chelating material in the form of acetic acid was added because of the extremely high iron precipitates found in the wellbore. These treatments were pumped at a rate of 4 to 6 BPM and the average treating pressure was 1200 psi. Instantaneous shut-in pressures varied from 0 (on vacuum) to 300 psi. Cleanup in all instances listed, except the third case, was rapid (Table 1).

CONCLUSIONS

1. Damage present in the formation due to particle migration in production fluids can create abnormal decline in production.
2. Iron stabilization should be added as a guard against dangers of iron complex reprecipitation when iron exists in excess of 0.2 percent in the formation.
3. All types of possible formation damage and test compatibilities of fluids to well fluids and the formation should be considered when recommending treatment for a well.
4. Silt-suspending acid additives should be residue free, possess low surface tension, prevent emulsion, inhibit corrosion, suspend solids, and be temperature stable.

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TABLE 1—FIELD RESULTS

Wells or Leases	Size Treatment	Production Before	Production After
1. Burbank	1000 gal 15% HCl w/ silt-suspending additives 6 gal acetic acid/1000	5 bopd 30 bwpd	15 bopd 42 bwpd 4 months 15 bopd 42 bwpd
2. Burbank	1200 gal 15% HCl w/ silt-suspending additives 6 gal acetic acid/1000	1.5 bopd 10 bwpd	3 days: 12 bopd 5 days: 30 bopd 4 months 28 bopd 25 bwpd
3. Burbank	1200 gal 15% HCl w/ silt-suspending additives	2 bopd 5 bwpd	5 bopd 19 bwpd
4. Burbank	1000-1200 gal 15% HCl w/ silt-suspending additives	8 bopd	50 bopd 250 bwpd
5. Burbank	1200 gal 15% HCl w/ silt-suspending additives	T/A	38 bopd 190 bwpd
6. Burbank	1200 gal 15% HCl w/ silt-suspending additives	3 bopd 144 bwpd	6 bopd 120 bwpd