A RE-INTRODUCTION TO OIL AND GAS WELL STIMULATION WITH CHLORINE DIOXIDE (ClO_2)

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ABSTRACT
Chlorine Dioxide (ClO_2) has been used as a well damage removal and stimulation fluid since the late 1980's. It was originally investigated as a means to remediate reservoirs of the permanently damaging effects of polymer, monomer, and polyacrylamide floods developed in the 1980's across many conventional oilfields, including those in the Permian Basin of West Texas, U.S.A. Chlorine Dioxide is a strong oxidizer and highly effective biocide, popular today for preparing frac waters and aiding in recycling produced waters, also to be used in fracturing. Many petroleum engineers and oilfield production personnel are not aware of the chemistry, or services available to remove the damaging effects of polymers, polyacrylamide, frac gel, gel filter cake, biomass / biofilms, Hydrogen Sulfide (H_2S), Iron Sulfide (FeS), Iron Oxide (Fe_2O_3), all species of bacteria including Sulfate Reducing Bacteria (SRB's), and many other oxidizable particles that have plugged and otherwise damaged all types of wells. Chlorine Dioxide has proven to be extremely effective in salt water disposal (SWD's) and injection wells, but has also found an important role in vertical and horizontal producers having production challenges such as Iron Sulfide, due to the infiltration of SRB's into the reservoir and the subsequent H_2S, FeS, and H_2S corrosion. This paper forms a summary of the ways Chlorine Dioxide, in conjunction with Hydrochloric acid (HCl), is used to remove wellbore damage, drastically reduce H_2S levels, and overall, restore the well's injectivity or productivity. In addition, the paper outlines the key aspects of treatment design to insure success while concentrating on practical field applications, as demonstrated in wells across the Permian Basin.

INTRODUCTION

Chlorine Dioxide (ClO_2) has been used in the industrial world for over 80 years. Chlorine Dioxide is a strong oxidizer and biocide, so was originally used in the treatment of sewer plants and paper mills. Uniquely, ClO_2 does not linger or remain active for very long, often only hours, before degrading and disappearing naturally. As a result, it can be used in strong and highly effective concentrations, but then self-degrades after oxidizing or completing the biocide action. This does make it suitable for oil and gas well use.

True ClO_2 is generated on-site for oilfield applications. The industry recognizes the inherent safety of a venturi-driven generator, using three pre-cursors to generate a >99% purity ClO_2 gas, which is immediately dissolved into a liquid carrying it down-hole; most often water.

Oxidizers became popular for oilfield use in the 1980's, including some dangerous ones, such as sodium hyperchlorite, or bleach, which could create free-oxygen in wellbores, depending on well properties. Unfortunately, the spirit of experimentation was out-pacing the safety aspects of many oxidant technologies and accidents occurred. The industry is still faced with the resulting negative criticism today, despite the later development of safe ClO_2 generating equipment, experienced personnel, and exemplary safety records. There are currently several dozen ClO_2 jobs ongoing in Texas each day.

EXXON pioneered the safe and reliable use of ClO_2 in the oilfield, and the first treatment was pumped in 1987, in the Permian Basin. That treatment used the selective oxidant to remove polyacrylamide from a conventional reservoir in the Snyder, Texas area.

Our Damaging Ways

Many of the operations we do to a completed well, such as; killing, clean-outs, injection with dirty or contaminated waters, over-production, fracturing, introducing bacteria via well fluids, non-utilization of breaker in cross-linked fluids, etc. can damage the natural permeability and/or plug the reservoir. Some of this is simply unavoidable, and some of it is carelessness. Regardless, it happens and we periodically need to restore a well's ability to either take fluid, or give fluid. Hydrochloric acid (HCl) is one of the most commonly used stimulation fluids in the oilfield, having a history that goes back many decades. HCl is a work-horse stimulation fluid in production operations, complete with its pros and cons. However, HCl has one major downfall: it does not remove most of the oilfield's biological infestations of SRB's, biomass and biofilms, and, further, it does not work well at removing frac gels, polymers, monomers, and polyacrylamides.

The oil and gas industry does not dedicate as much attention to fluids going into injectors and SWD's as those coming out of producers (cost versus revenue); that is logical, and they are improving; but this lack of attention and discipline can cause permanent damage to the reservoir and costly damage removal later. It is an ongoing battle that will be with us forever in the oilfield. Filtration, biocides, corrosion inhibitors, oxygen scavengers, injection pumps and piping infrastructure, and other injection water treatments cost real money. As a result, they can often fall prey to cost cutting measures during lean years of lower oil prices.

Fortunately, chlorine dioxide with the addition of HCl, performed in many stages, has proven to be effective at cleaning up the damage described, and the purpose of this paper is to review the methods and look at the overall results of such treatments. We will review a set of 46 wells, show how these wells were treated, and offer suggestions for the future.

THE DATA SET

The sampling of jobs in this review consisted of 46 wells in the Permian Basin:

- 7 SWD's, all vertical
- 15 Injectors, all verticals
- 24 Producers (approximately half of them were horizontals)

WHAT HAS CHANGED?

The industry as a whole is doing better today at recognizing and reacting to common oilfield biological problems that used to go overlooked, or were misunderstood by oilfield personnel.

1. Prevention - The biological impact of having SRB's and other bacteria in the reservoir can be devastating on fluid movement, can cause a whole bunch of different operational problems (i.e.- H_2S corrosion, pump failures, permeability plugging), and they can be very expensive to control over the life of the well and field. It is far more economical to control the bacteria problem before it proliferates in the reservoir. For many mature fields, it is simply too late to stop the proliferation, so it is now a constant battle to reduce bacteria to a level where normal injection or production can be maintained at economic levels.

2. Removal - Biomass, also known as biofilm, slime, bacteria, bio-sludge, and bacterial colonies, cannot be removed by acidizing with HCl. Conventional biocides have a difficult time penetrating established biomass, slime, or bacterial colonies. The extremely small ClO_2 molecule, acting as a strong oxidizer, is able to enter and tear up the biomass and the bacteria's body and defense mechanisms, and completely destroy and remove biomass, bacteria, and slime. This biomass removal was directly observed on the pressure versus rate charts during several SWD treatments, during long ClO_2 stages. One SWD was so badly damaged by biomass that the ClO_2 and HCl treatment resulted in a doubling of the SWD injection rate, at half of the wellhead injection pressure. That SWD was being acidized every month in an attempt to keep it on injection. After the ClO_2 treatment, it went over a year before being treated again, accumulating

substantial financial savings to the operator, in the form of electricity bills and acid treatment costs. Recognizing the signs of biomass are outlined later in this paper.

The Roles of the HCl and the ClO_2:

- Hydrochloric Acid – 15% and 20% HCl is used for the removal of rust, iron carbonate (often associated with iron sulfide), calcium carbonate, and iron sulfide. It has another important role, however, and that is to be the first chemically active fluid to hit the perforations or open hole directly after dropping the diverting agent (balls, Rock salt, resins, etc.) and for aiding in breaking down the next set of perforations or open hole to accept the next stage of ClO_2.

- Chlorine Dioxide - ClO_2 used at a concentration of 3,000 ppm, is used for the removal of all types of bacteria, including APB and SRB's, biomass, slimes, biofilms, H_2S, polymer, monomer, polyacrylamide, gel residues and filter cakes, rust, and iron sulfide.

<u>PRIOR TO THE TREATMENT – IDENTIFYING THE PROBLEM & CHOOSING THE CANDIDATE</u>

It is prudent to do a pre-job investigation prior to the treatment, ensuring the use of ClO_2 is warranted. ClO_2 has a specific purpose and function in the acidizing process, outlined in the preceding paragraph. So, make sure the conditions exist that will give you a successful treatment using ClO_2. ClO_2 will not damage the reservoir in any way, but if it is not needed, it is not a good investment and is considered a misapplication of the chemistry.

The very best indicator of biomass, or biological slime occupying and plugging an SWD or injector, is that HCl acid treatments become less and less effective at restoring injectivity, and become required more often. This statement might be the best take-away of this paper.

Other indicators that you have biomass or slime, or that you have operational problems directly resulting from bacterial infestation and colonization, are:

- The presence of Hydrogen Sulfide (H_2S) and Iron Sulfide (FeS).
- The FeS can often be found when pulling a failed pump.
- "Shooting bug bottles" and finding several bottle turns quickly; this field test on produced or injected waters is a clear indicator of bacterial infestations. (Figure 3)

Bottom Hole Sampling

On several of the injector and SWD wells, the operator flowed the well back to catch fluid samples from the reservoir, for the purpose of testing bacteria and H_2S. This was accomplished by flowing-back the volume of the well casing and tubing, plus typically 50 – 80 bbls. over the well capacity. This will bring back fluids which are relatively near wellbore, but originally from the reservoir. This is a very effective way of proving the need for a ClO_2 treatment. H_2S, and ATP (Adenosine triphosphate) can be measured immediately on location, for an accurate count on the H_2S and bacteria counts. Another useful measurement is ORP (oxidation-reduction potential, or Redox). Bug Bottles (see Figure 3) should also be shot and incubated for determining the SRB counts, general bacteria count, and acid producing bacteria counts. Use extreme caution, as high H_2S levels are possible; several SWD operators were shocked at what flowed back.

Tubing Considerations

Most of the tubing used for injectors and SWD's in the Permian Basin are lined with protective coating or powdered epoxy. Many operators use an unlined work-string for the treatment since it is typically on location for wellbore cleanouts and bit and scraper runs. Although we have never encountered any incompatible fiberglass or internally coated tubing, unable to withstand the rigors of an HCl and ClO_2 treatment, it is better to be safe than sorry. Test a sample of the coating or a pup-joint of tubing in the stimulation fluids for several hours and visually inspect the specimen for any detrimental effects of the chemistry.

<u>DIFFERENCES IN TREATING SWD'S, INJECTORS, AND PRODUCERS</u>
Flow-backs / clean-ups

This may not be obvious to some, but when acidizing these three types of wells, the procedure is not identical in most cases. There are strong arguments for both flowing wells back and not flowing wells back after a treatment. In the wells studied by this group, the injectors and SWD's were not flowed back. We believe the benefits of not flowing back the SWD's and injectors is the wellbore remains clean after the treatment, and fluid continues to flow from the wellbore into the reservoir. The results have shown good longevity and very positive injection increases.

Chemistry

The job requirements are very different depending whether the well is flowed back or not. For injectors and SWD's, since they will generally not be flowed back, it is not cost effective to load up the HCl acid with iron retention chemicals, anti-sludging agents, or excessive amounts of non-emulsifiers and surfactants, since the acid will stay in motion and be pushed away from the wellbore by both the ClO_2 and the overflush. Sludging of oils is not a big concern in injectors or SWD's, and so long as the acid has some basic surfactant in it to keep everything water wet, the rest of the chemistry can remain fairly simple. The biggest aide to a successful treatment is the use of sufficient amounts of HCl, so the acid stays "live" longer in the reservoir. For example, stages of 200 gallons of acid should be avoided. Realistically, 200 gallons of acid has very little impact on the treatment, and could possibly be spent by the time it reaches the next set of perforations or open hole. Small volumes of acid can actually damage the reservoir by depositing iron precipitates near the wellbore region. ClO_2 can and will prevent this from happening, but the point made is that more acid stays "live" longer and keeps the iron present in solution. (Figures 1 and 2)

For producers which will be flowed back, there is an alternative recommendation for acid chemistry. "Shake Test" emulsion testing should be performed prior to the treatment, with spent and live acid recipes, containing realistic amounts of dissolved iron. Iron chelating and sequestering additives are very important as the well flows back or produces back its load of spent acid and spent ClO_2 (essentially, salt water with some CO_2 gas). Simply put, when an HCl and ClO_2 job is performed, dissolving iron sulfide and carbonates, if in a sour well environment, results in a tremendous amount of iron released and can potentially cause iron stabilized emulsions. Good emulsion / anti-sludging tests should be performed prior to treating producers. There are many good references on this subject, and good acidizing companies should have procedures in place to recommend what is needed to stay out of trouble during the load recovery phase.

Two types of ClO_2 treatments are common:

1. Bio-remediation of producers, often with pumps in the hole and treatments pumped down the annulus. The goal here is to reduce the SRB bacteria and H_2S levels. No diversion is used, so contact area may be less than desirable, but operators are satisfied with the reduction of H_2S, the removal of FeS, and the longevity of the treatment. This type of treatment has extended and restored pump life to ESP's and rod pumped wells. It has also shown to be effective in flowing horizontal wells.

2. The more traditional treatment looks very similar to multi-staged HCl acid jobs using diverter. This treatment is explained in detail in the next section.

<u>THE PROCEDURE USED ON MOST OF THE WELLS IN THIS SAMPLING (DIVERTER JOBS)</u>

1. Ensure that the entire perforated interval, or open hole section, is open; either by running a sinker bar to PBTD or running to bottom with a bit and scraper. Note: In this sampling of jobs, none of the horizontals were treated with diversion. So, all of the diverter jobs were verticals.
2. Pickle the tubing if possible. Pickle only when the pickling fluid can be returned to surface.
3. Rig up the acid pumping crew and the chlorine dioxide crew.

4. Hold a pre-job safety meeting; designate a muster point up-wind from the location that is easily accessible for all personnel on location. Count heads and make sure all personnel are aware of the handling and pumping procedures for HCl and ClO_2. Discuss JSA's and review the location and working order of fire extinguishers, SCBA's, chemical showers, etc.
5. Establish a workable injection rate into the formation using brine, treated water, or 2% KCL water; this is simply to insure that the reservoir is accepting some fluid before loading the tubing with HCL acid and ClO_2. (3 to 4 BPM is acceptable)
6. Pump the first HCL acid stage; this 15% or 20% HCl acid stage is typically 1.5 times larger in volume than the rest of the HCl stages due to the need for more acid to take care of wellbore cleaning, removing rust, and keeping live acid going out the perforations, during stage 1. (For example, 750 Gallons = 18 Bbls.)
7. Pump a 5 Bbl. Spacer (normally fresh water, or 2 % KCL water)
8. Pump the first stage of ClO_2 (for example, 40 Bbls. of ClO_2 at 3,000 ppm). See comments about volumes of ClO_2 in the "General Observations and Comments" section below.
9. Pump a 5 Bbl. Spacer (normally fresh water, or 2 % KCL water) to clean out the ClO_2 hoses.
10. Overflush the entire stage with 35 Bbls. of water (can be fresh water, brine, or 2% KCL water)
11. Pump a 5 Bbl. Spacer of 10 ppg Brine ("ppg" meaning pounds per gallon fluid density). (1.2 S.G.)
12. Pump the first Rock Salt Diverter block in 10 ppg Brine (Rock Salt dropped at approximately 2 ppg); "ppg" meaning pounds per gallon, in this case, the concentration of Rock Salt in the Brine carrying fluid. Normally, the first block is conservative in size, for example, 500 - 750 pounds of Rock Salt. See comments about volumes of Rock Salt in the "General Observations and Comments" section below.
13. Pump a 5 Bbl. Spacer of 10 ppg Brine (1.2 S.G.) to isolate and protect the block.
14. Pump the second HCL acid stage; this 15% or 20% HCl acid stage is typically 500+ Gallons = 12 Bbls.)
15. Pump a 5 Bbl. Spacer (normally fresh water, or 2 % KCL water)
16. Pump the second stage of ClO_2 (for example, 44 Bbls. of ClO_2 at 3,000 ppm). See comments about volumes of ClO_2 in the "General Observations and Comments" section below.
17. Pump a 5 Bbl. Spacer (normally fresh water, or 2 % KCL water) to clean out the ClO_2 hoses.
18. Overflush the entire stage with 35 Bbls. of water (can be fresh water, brine, or 2% KCL water)
19. Pump a 5 Bbl. Spacer of 10 ppg Brine ("ppg" meaning pounds per gallon fluid density). (1.2 S.G.)
20. Pump the second Rock Salt Diverter block in 10 ppg Brine. Normally, the second block size is increased depending on what was observed when the first block got to the formation. For example, if 500 - 750 pounds of Rock Salt did not have any effect, it might be decided to double the next block size. See comments about volumes of Rock Salt in the "General Observations and Comments" section below.
21. Pump a 5 Bbl. Spacer of 10 ppg Brine (1.2 S.G.)
22. Pump steps 14 – 21 over and over, until all the stages are pumped.
23. Flush to bottom plus 35 Bbls. of overflush using fresh water or 2% KCL water; it is not recommended to leave brine in the wellbore at the end of the treatment, fresh is preferred to dissolve rock salt.
24. Resume injection as soon as practical.

HSE improvement during the treatments

One of the steps which has been taken to reduce the risk of ClO_2 exposure to people, equipment, and the environment, was implementing a method whereby the suction and discharge hoses carrying ClO_2 are displaced at the end of each stage and replaced with fresh water (or 2% KCL water). It would be a good practice to do this on the HCl acid side as well. The goal was to eliminate the ClO_2 from sitting in suction and discharge hoses during temporary unplanned shut downs, which sometimes occurs in acid treatments (like a leaking wellhead, re-setting the packer, or needing to pressure up on the TCA (tubing / casing annulus)). There have been some delays observed which take hours to resolve, and eliminating that unnecessary risk on location is beneficial.

CONCLUSIONS

1. ClO_2 and HCl stimulation / damage removal treatments can be pumped safely and effectively under common oilfield conditions. The method of ClO_2 generation is an integral part of the overall safety.
2. Both types of treatments have shown to substantially reduce the levels of H_2S, SRB's, and FeS in the wells.
3. HCL / ClO_2 staged treatments have shown to be effective at removing reservoir damage associated with FeS, Biomass, slime, SRB's, all forms of bacteria, Iron Carbonate, and Calcium Carbonate.
4. ClO_2 can extend the working life of a rod pump, or ESP, showing signs of sticking from FeS.
5. ClO_2 substantially extends the period of time between acid treatments due to injection or disposal water plugging of the formation, in the presence of biomass or slimes.
6. Fine grained Sodium Chloride Rock Salt (like 30/70 or 20/40 mesh), when used in sufficient quantities with 10 ppg brine, can provide adequate and reliable diversion in perforated and open hole completions.
7. Rate is important in HCL / ClO_2 staged treatments, just as it is in traditional HCL acid treatments. A good place to start with rate, to achieve acceptable diversion using fine grained rock salt, is casing size plus 2 BPM. For example, 5 ½ casing requires 5 BPM plus 2 BPM, or 7 BPM. Rate is also important in driving "live fluids" deeper into the reservoir. In other words, rate will help overcome the reaction rate of the chemically active fluids. Both HCL acid and ClO_2 have rapid reaction rates in-situ; especially HCl in carbonates.
8. From the 46 wells treated, 4 were dropped from the study (misapplications), and one was considered unsatisfactory, as it appeared to have "no change". The other 41 treatments were considered successes. To date, there is no proven explanation for the well that exhibited no change in injectivity. An 89% success rate with ClO_2 is much higher than the industry standard for HCl treatments.

GENERAL OBSERVATIONS AND COMMENTS

- Most operators do not use enough Rock Salt block. This is common sense, they do not want to risk plugging the entire wellbore. In the 30 aggressive salt block diversion treatments, they never blocked off the entire wellbore, and they were always able to complete and flush the entire treatment. Several came close to being 100% blocked, but they managed the rate (sometimes as low as 0.2 BPM), and were able to re-establish rate when the HCL acid reached the formation.
- Rate is dictated by tubing size and allowable pressure rating, as it is in any stimulation treatment. Prepare and plan for increased rates and pressures. It is not uncommon to get 3,000 psi increases in surface treating pressure. For treatment rates, follow the "rules of thumb" found in #7 of the Conclusions section.
- Large tubing SWD's (3 ½" tubing and larger) give the opportunity to increase treatment rates. One SWD in this well set was a 4 1/2" completion at approximately 7,000 feet. That well was treated at 16 BPM, and had very good results.
- Injectors and SWD's gave good results by returning them to injection, rather than flowing them back.
- Use a good wind sock; and pay attention to it throughout the treatment. The wind sock is the primary means of managing the HSE on location during the job since inhalation of HCl and ClO_2 fumes, though rare, are one of the primary HSE concerns.
- Overflushes were used on most of the treatments; at the end of each stage. We believe they are beneficial to the overall success of ClO_2 treatments in all types of wells, including producers. There is no sense in leaving live ClO_2, adjacent to the perforations (or open hole) which are highly cleaned by the first portions of the stage. Using overflushes not only leaves the near wellbore area clean, and makes the best use of the live ClO_2 remaining in the stage, but by pushing live ClO_2 deeper into the reservoir, it pushes the inevitable iron precipitates away from the wellbore, leaving the near wellbore area highly conductive to flow. It is nearly impossible, if not impossible, to keep the 15% acid live long enough to return it to surface during a normal or energized flow-back, therefore, one of the detrimental effects of acidizing is always going to be iron precipitation (At least until ClO_2 is part of the process). ClO_2 will significantly change the

chemistry of the injected fluids as the HCl acid spends in the reservoir, hydrolyzing the dissolved iron. ClO_2 will keep much of the iron in solution, taking it far out into the reservoir. This statement is supported by the information at the end of the paper in Figures 1 and 2; which demonstrates the difference in conventional acidizing versus enhanced acidizing with ClO_2.

- The early stages of a multi-stage treatment are there to help clean up areas of the wellbore that may be damaged, but are still accepting or giving up fluid. Obviously, the first stage of the treatment is going to the path of least resistance, which may or may not be damaged very much, since it is still moving fluid well. In many cases in the Permian Basin, the water bearing zones are more easily pumped into, so limit the early stage size, remove damage while trying not to stimulate the water bearing zones, and spend resources where they are needed most, in the later stages of the treatment, which may be good permeable zones that are highly plugged from years of neglect. This philosophy has worked well.
- Chlorine Dioxide stage size is best demonstrated with the following actual treatment design, using seven stages of ClO_2. Let's say we want to pump a total of 390 Bbls. of ClO_2 into an injector, over 275 feet of perforations; and we have agreed to use seven stages. We would divide the 390 Bbls. into seven stages, such that the seventh stage is approximately 1.7 times as large as the first stage; this results in the following stage sizes: 43, 47, 51, 55, 57, 63, and 74. It is not exact science, but rather, an attempt to put the ClO_2 fluid where it is needed most. This philosophy works in acidizing, and there is no reason to believe it will not work with ClO_2.
- The acid ahead of the ClO_2 is a practical decision based on lots of jobs performed. When you drop rock salt blocks, you often find perforations that have never been broken down properly (in most wells). So, as the block (diverter) does its job of sealing off where the last stage went, we want acid to be the next and closest fluid to the perforations, to break down the perfs that previously never took fluid. We would have certainly been in trouble several times, had that stage of acid not been there.
- We would like to see the acid stage after the ClO_2 put back into the treatment program. Many operators removed the second stage of acid to cut cost. It makes good common sense to remove additional acid soluble debris after taking the slime and biomass off the reservoir face, and core studies indicate the best results are obtained when acid precedes and follows the ClO_2. None of the jobs in our array had the acid to follow the ClO_2.
- Treatment volumes should be based upon past successes, not based upon theoretical pore volume calculations assuming matrix flow through a porous medium. A very good starting point would be 100 gallons per foot of gross pay. That number is based upon experience and is validated in many stimulation manuals. Always take a rule of thumb with caution; ask what has worked well with other operators under similar conditions. You may also refer to the papers in the references.
- The great unknowns, particularly in horizontals, are the conditions of the wellbore. Verticals are fairly simple in that a sinker bar can be run to find HUD / PBTD, but in horizontals, we do not have that simple step to determine whether there is access to the toe. Complicating the matter, most wells are either toe-up or toe-down, and have highs and lows in their trajectories, which promotes sand banking and other production problems. When undertaking a treatment, it is best to know if you have access throughout the entire perforated or open hole interval before making the investment of the treatment.
- Rock Salt Block Sizes – Very subjective and debatable, but as the job progresses, you most definitely want to see diversion pressure transmitted back to surface. The whole idea of using the Rock Salt, in large quantities, is so that we get measurable and effective diversion (the most important requirements of the job). Block sizes typically get bigger in size (drop more rock salt) as the job progresses, up until it generates several thousand psi of extra pressure, confirming that you are beginning to block off previously treated zones, and giving hope that the next stage will indeed treat a different part of the well needing biomass removal. There are many ways to estimate how much Rock Salt to take to location, but the single best way is to see how that reservoir in that field accepted the previous treatment, and always have extra rock salt on hand for the difficult to divert well. In the Permian Basin, it is not unusual to consume 10,000 pounds of rock salt on an injector, or 20,000 pounds of rock salt on an SWD. Producers are usually more conservatively perforated, and more rarely open hole completions, but a rough and average

number might be 7,500 pounds. In the complete absence of any offset data, you can try 6 pounds of Rock Salt per perforation, but have plenty of extra on hand. The final note on dropping rock salt is that the amount of acid that has been pumped into a carbonate reservoir definitely affects the amount of rock salt required to get adequate diversion.

- The number of stages is based upon experience and common sense. The past is the best indicator of what worked under similar conditions. One method, is to plan a stage for every 50 feet of perforations (in a vertical hole). More stages, rather than fewer stages, allows the treatment to be adjusted and customized "on the fly". Three stages would be considered a minimum, five to seven stages the norm, and more stages can be added to get adequate coverage of very long perforated or open intervals; or multi-staged Plug & Perf horizontal completions, which may have 30 – 60 stages.

DISCUSSION – FUTURE TREATMENTS

Every well is different. Avoid the "cookie-cutter" approach. Study the well completion, perforated interval, open hole section, previous stimulation history, historical injection or production data, and reservoir characteristics, and custom design each job to fit the requirements of the individual well and its offsets. Let results and HSE be the drivers of design.

It would be useful for the industry to develop a corrosion inhibitor for ClO_2 / HCl acid treatments. It is understood that high purity ClO_2 by itself is not corrosive, unlike most other strong oxidizers, but the action of ClO_2 on acid inhibitors degrades the effectiveness of the HCl acid inhibitor by stripping the inhibitor off the pipe. Higher doses of inhibitor are required to recoat the ID of the pipe surfaces each stage. The corrosion inhibitors need to work effectively in the total staging system, consisting of HCl acid, brine, and ClO_2.

The downturn in the price for oil, 2014 to 2016, forcibly cut the treatment designs and effectiveness of the jobs performed. Treatment volumes, of both the HCl and the ClO_2 need to increase, back to industry recognized volumes of effectiveness. For example, pumping stages of 200 gallons of HCl acid is not realistic, nor effective.

Cost control has driven out the second stage of acid, after the ClO_2 stage. We hope to see that re-instated as the burden of extreme cost analysis eases up in the future. Most of the treatments reviewed in this paper were performed in 2016, when "cost was king". Other proven useful aspects have been removed also, for cost (straddle packers, perforation ball sealers, coiled tubing).

For producers, we prefer a combination of Rock Salt and Benzoic Acid; oil soluble resins, polyactic acid, biodegradable ball sealers, or some other particulates that will dissolve with time and temperature, in any fluid, including natural gas.

We recommend reading the referenced papers.

We recommend using some form of diversion on every job, if at all possible.

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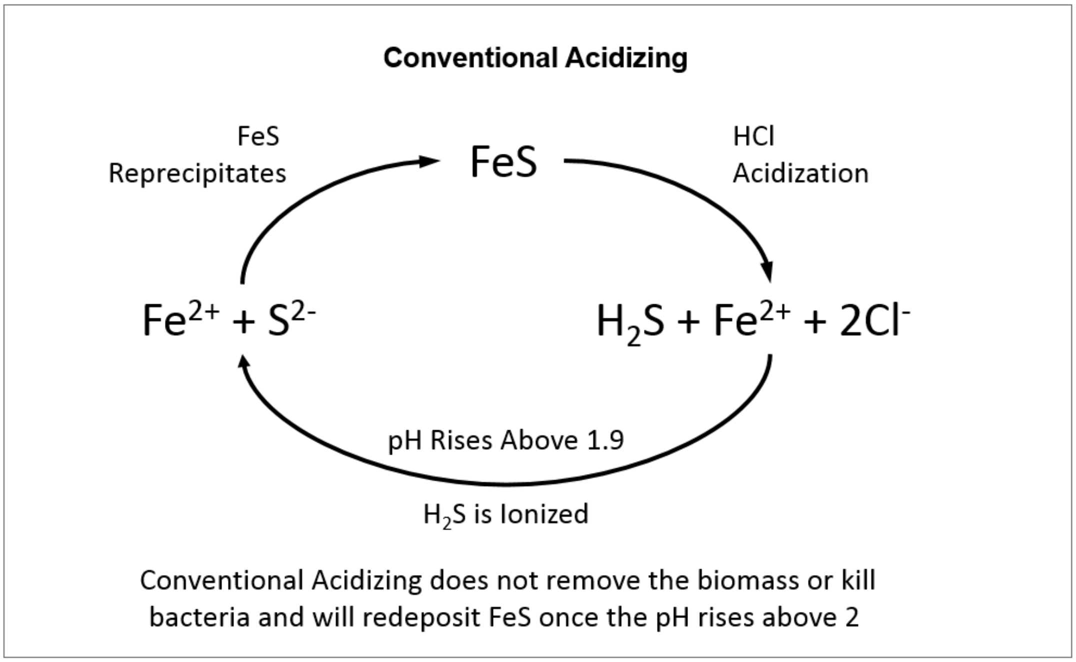

Figure 1

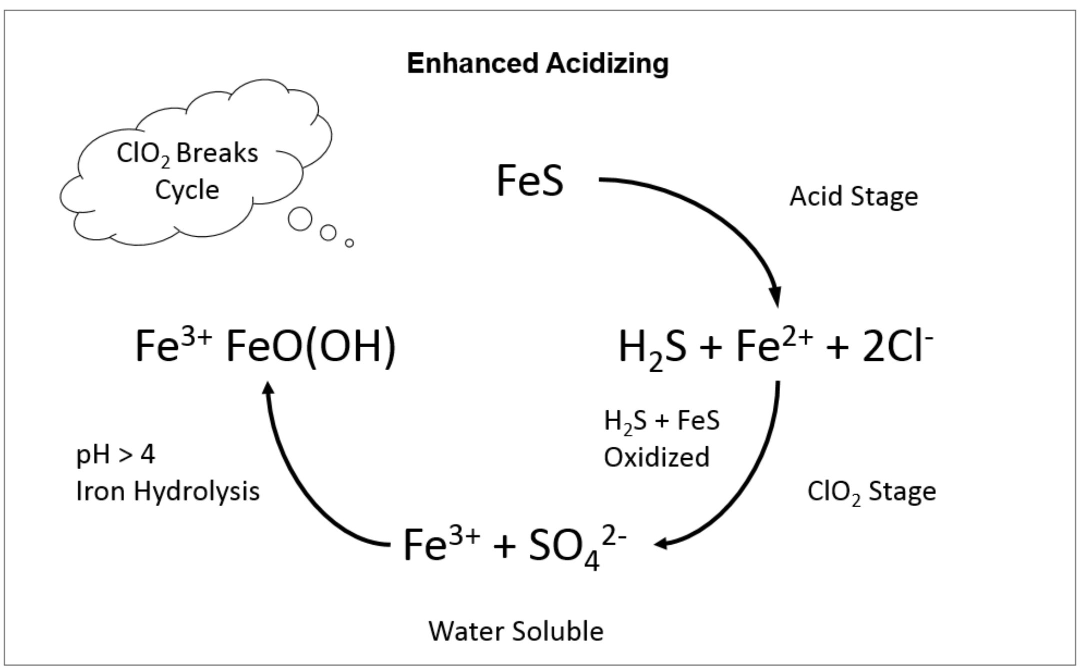

Figure 2

Figure 3