CORRECTING OUT-OF-ZONE INJECTION PROBLEMS ON A WATERFLOOD IN SE NEW MEXICO

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ABSTRACT

Due to out-of-zone injection problems in a waterflood unit, investigations and a designed remediation to the problems were developed using diagnostics and new technologies with super-absorbent, crystallized copolymer (CP) systems.

Current profiles with their rates and pressure transients were analyzed through multi-rate injectivity profile analysis. Criteria were then established for the physical and chemical attributes needed by the solution designed to address the problems. The diagnostics, while determining the problems and to what extent they were occurring, were also used to determine the placement control needed for a solution treatment. Once the needed physical, mechanical, and chemical aspects were analyzed, selection was restricted to solutions that would withstand the detrimental effects of CO_2 injection and resistance to bacterial growth potentials.

Shown are methods of diagnostics used, selection processes for needed attributes and solution capabilities, and the placement performance of the solutions. Treatment results show the process performance.

INTRODUCTION

In many water and CO_2 WAG flood units in southeast New Mexico and the Permian Basin of west Texas, out-of-zone injection can occur because of many circumstances, either mechanical in nature or due to chemical/electrolysis reactions. The conditions of the shallow Dolomitic formations where most of these water and/or CO_2 WAG floods were placed can contribute to injectivity outside the desired interval because less pressure is required to gain entry. The formations discussed in this paper are the Grayburg, San Andres, Glorieta, Paddock, etc., formations of Permian Age. Most of these formations were deposited in shallow-shelf carbonate environments along the western shoulder of the Central Basin in west Texas and SE New Mexico. Natural fractures and karsted intervals often dominated the injection paths and could be very directional. Variations in the content of anhydrite within the Dolomitic formations also exhibited differences in stresses and integrity to withstand injectivity. These layered, highly dolomite reservoirs had significant permeability variations.[1, 2]

Variations in permeability and porosity were complicated for the formations because of their layered nature, with the content of anhydrite ranging from a small percentage to being the dominant rock content. These formations are characterized by multiple layers with discontinuous areas caused by widespread impermeable layers. Most of the current recovery in the western platform is attributable to pressure maintenance through waterfloods and miscible floods using CO_2. Permeability contrasts within the various layers are responsible for the varying degrees of effectiveness of water and CO_2 injections. Development has led to many injectors communicating directly to the offset producers. This usually becomes more evident when CO_2 operations begin. Typical completion depths are 3,000 to 6,500 ft.

Conditions in lithology, rock structure, and geological histories can limit the ability to achieve a balanced flood due to the rock properties and architecture existing in the reservoirs. Fractures, fissures, and highly eroded permeability may exist due to these naturally occurring conditions or can be caused by operational practices and old completion methods.[1, 2]

A conformance design using a dehydrated crystallized copolymer (a proprietary material consisting of dehydrated copolymer crystals) has been implemented to control the loss of injection fluids into these unwanted zones. This design was based on injectivity log profiles, formation reservoir characterization studies, and analyses of the issues regarding step-function changes needed to accomplish the required tasks. This paper will cover the ongoing work and processes/methods used in the floods. The focus was to: (1) keep open evaluation processes to gain knowledge from lessons learned, (2) use advanced products and techniques, (3) identify and discover more about the problems, and (4) apply useful processes to increase successes and economic benefits by reducing wastes and inefficiencies caused by out-of-zone injection.

A need exists in the industry to address this feature in these types of wells and to help create greater economic gain when applying a flood—whether applied with water or with an enhanced CO_2 WAG. Current conditions in the wells often lead to even larger communication problems that cause higher cycling of the injectants and greater loss of in-pay pressure support.

DIAGNOSTICS

Diagnosing and analyzing the necessary placement controls based on the identified conformance problem is the primary task needed to achieve success. In developing a solution for the identified problem, it should have the capability to be placed successfully at the targeted part of a reservoir without becoming an obstruction to beneficial production and fluid displacement.

Choosing and designing the proper conformance solution based on the needs of the subject wells can also lead to a successful and long-term remedy for the problems. Many solutions are available, such as (1) liquid systems with in-situ polymerization post-placement, (2) fibrous materials that produce a flexible blockage, (3) crystallized copolymer systems capable of entering and modifying highly leached and fissured rapid fluid transient fissures and fractures, (4) reactive chemicals with both internal and external catalysis, and (5) high-strength, highly efficient displacement materials capable of blocking or modifying fracture systems with rapid communication between well-pairings.[2]

Post-treatment evaluations are needed after modifications or changes in well performance to ensure that the problem has been successfully remedied. Efforts to reflect on what may be discovered and learned without making judgemental assumptions should be incorporated into the investigation for a solution and its successful placement.[2]

COLLECTING INFORMATION PERTINENT TO THE PROBLEM

The following are required in this accumulation of problem identification resources:

- Reservoir descriptions and drive mechanisms.
- Maps and schematics, including well, structural, and completion diagrams.
- Data files, or files containing all well information, well tests, and production and injection information.
- Type logs showing formation tops for the subject producing interval with additional geological markers shown.
- Individual production and injection plots for all wells for the same time period.
- Water cut and water-oil ratios.
- Test results for tracers, profile and temperature logs, production logs, pressure surveys, pulse testing, etc.
- Historical injection rate and pressure data

PROBLEMS CONFRONTED

As noted previously, most of the formations in these units are characterized by multiple layers with discontinuous areas caused by widespread impermeable layers. Adjoining formations are often not separated by any barrier and can communicate readily. Often, problems displaying out-of-zone injection are first noticed because of cycling problems with one or more of the injector's offsetting producers. The direct communication between injectors and producers is referred to as cycling and appears as a very rapid spike in injectant production volumes in the producers shortly after the injection cycle starts. This increase in injectant production volume is usually accompanied by a decrease in oil production volumes. The other flag used to identify problems is offset wells that are not performing based on pressure support when injectivity has been lost to another zone not connected to the desired interval.

Wellbore losses and lack of integrity usually display similar conditions with a potential for water influxes and cross-flows prevalent within the problem intervals. Often, injectivity patterns follow fracture paths that lead across flood units and offer dynamic interference to any attempted solutions meant to remedy the conditions. Hazardous conditions also exist with the presence of H_2S and iron sulfide content. Existing conditions and the physical nature of the problem should be addressed when defining the attributes and capabilities of a proposed solution; the solution's placement capabilities and required controls should also be defined.

As an upfront review, problems with non-support in injection due to losses or highly communicating injectivities without benefit may be recognized in the wells; however, to help define capabilities when attempting to remedy these problems, the following factors should be considered:

- Potential for high probability of success.
- Return on investment potential.

- Amount of data available.
- Past maintenance and workovers.
- Are there corrosion problems?
- Equipment replacement and facilities capabilities and optimization needs.
- Are workovers needed to treat paraffin and scale removal via acidizing, etc.?
- Disposal needs and cost, regulatory requirements, and environmental issues.

Out-of-zone conditions usually lead to additional problems, such as increased near-wellbore corrosion, loss of wellbore integrity, and difficulty in maintaining a packer seal.[1]

Reservoir evaluations rather than individual well evaluations (which may be influenced by mechanical or near-wellbore problems) should be used to determine the value of addressing problems with injectivity losses or inefficiencies. Solutions designed to remediate these problems could possibly address reservoir sweep problems and interwell communications. The anticipated outcome still is directed toward the goals of increased production and recovery with an associated reduction in operating costs.[3]

Historical injection profiles, completion and stimulation details, and timeline occurrences were obtained on the subject wells.[2] Wells were usually selected for treatment according to a prioritized list of injector/producer pairs or combinations of associated wells that resulted from the flood performance. These wells were reviewed again to eliminate those with known mechanical problems, and a diagnostic program was generated.[3]

After a conformance candidate was selected, injection profiles were obtained on the subject well before a treatment was designed. Multiple injection profiles were run on each subject well under normal operating conditions as well as at reduced and increased injection rates and pressures. These survey logs were sometimes obtained on both the water and CO_2 cycles to determine whether injection was entering the same intervals regardless of the injection fluid. These injection profiles were used for designing and placing the conformance treatments, which were tailored to each well's requirements.

In performing injectivity analysis, one needs to understand where the fluids have gone at different conditions. The conditions that vary are the pressure changes associated with different injection rates and the variations in injection profiles. These multi-rate analyses are conducted with a logging tool in the hole equipped with a release device capable of placing a specified amount of radioactive material into the flow stream above the logging tools. A required base gamma analysis is used for determining variations. The testing is performed with velocity releases of isotopes placed in segments through the wellbore, followed with a large intensity shot of isotope placed above the entry zone. The process is started at a reduced rate below the daily injection rate. By releasing the velocity shots and an intensity shot, engineers can trace the injectivity of the tag to determine its path and location. Comparison analysis with both intensity and velocity shots provide a better understanding of injectivity and static conditions crossflow determination.

Combining these analyses with a temperature analysis provided a better understanding of injectivities and near-wellbore effects. Subsequent runs for multi-rates were taken at incrementally increased rates after time was allowed for the previously shot isotopes to clear and for fluid entry to stabilize. Crossflows were determined between each step as well. The next rate steps were performed by increasing the injection rate and ensuring that the bottomhole injection pressure (BHIP) did not exceed the fracture gradient. The purpose was to determine whether entries varied at the various rates and at any accompanying changes in BHIP for each injection phase with water and/or CO_2.

Variances of entry into the intervals needing correction were analyzed, and limitations were determined for the placement technique. The proposed solution's criteria and attributes were established from the injectivity evaluations.

Along with determining the extent and condition of the problem, there was opportunity for determining the required criteria of the treatment solution and the placement technique that should be used. Various placement methods exist and can be designed into the plan. Maximum injection pressure can be determined for bullheading the treatment fluids based on the communication problems identified. Differential pressure responses may indicate the tortuosity aspects of fluid entry into specific portions of the reservoir. When rates exceed certain velocities, such solutions as cement slurries, gels, or particulates can be pumped into a specific portion of the formation. With normal permeabilities ranging from 0.1 to 230 md in the unit's Permian Age reservoir, there was little chance of injecting a gelled fluid at the placement rate determined from each of the multi-rate injectivities at matrix flow. This analysis helps investigators determine whether a treatment should be placed where it develops a blocking and diverting effect without entering other undesired portions of the formation. If investigations show that a specific pressure that develops from varying injectivity would cause undesired entry, this information can be used to limit the treatment pressure. The solutions that can be placed under the established criteria in the multi-rate injection analysis are established with this analysis.

The nature of an architecture that accepts high rates of injection is mostly that of fractures with characteristic leaching and erosion from years of water being forced through the structure. With units that have had the reservoir pressure increased to a desired pore pressure, these features can be seen for multi-rate injectivities with profiles, but pressure responses will be "masked" because artificial pressure is being maintained on the reservoir. This is especially the case when another formation is leaking into the well with the displayed losses due to out-of-zone injection. An assumption likely would be that the problem is due to a permeability feature and not with a fractured system. Analyses being used to determine the criteria for a solution may miss a diagnosed feature, resulting in operations that select the wrong technique and/or product to address the problem.[1,4]

FRACTURE CONDITIONS

On wells where identified problems consisted of fracture and vugular communications aspects, treatments utilizing a crystallized copolymer system were performed. These materials were used to address fracture and fissure communication to keep these highly communicating features from thieving most of the injection and transmitting it almost directly into offset producers. The crystallized copolymers used are resistant to degradation by CO_2 and bacteria and have a temperature range of 70° to 250°F. Placements were made down current injection tubulars working rigless, a practice that can save expense by avoiding the need for a workover unit. Removal of the crystallized copolymer could then be obtained by reactions from bleaches or oxidizers, if needed.

SOLUTION DEVELOPMENT: SELECTING A PLACEMENT METHOD

The initial inclination is to attempt a solution without thoroughly identifying the problem and the conditions in which it exists. Solutions should be considered and offered only after thoroughly analyzing a problem or need. Ideally, operators perform diagnostic tests to correctly interpret problems and develop necessary criteria and requirements. The required attributes of a solution should be defined according to the desired parameters of the need. The available solution's limits, qualifications, and "ability to place" should be developed accordingly. The designer should match the best solution system or techniques to meet the necessary attributes required and provide the most favorable economics for each well or pair of wells treated.

In regard to placement, solutions are based on the extremity of the required placements and their proximity to the wellbore. Some considerations made include:

- Near-wellbore problems
- Casing leaks and integrity problems
- Channels behind casings
- Barrier breakdown problems
- Completion out of zone
- Reservoir problems
- Poor areal sweep conditions, e.g., heterogeneity, discontinuity, etc.
- Gravity segregated layering
- Cone-in/cresting (cusping) problems
- High-permeability streaks (with or without crossflows)
- Stimulation out of zone
- Inter-well channeling (fissures/fractures)

FRACTURE COMMUNICATION AND OUT-OF-ZONE LOSSES

Wells in which an identified problem consisted of fracture and vugular communication aspects, were addressed with a crystallized copolymer system. CPs are water-swellable (but not water-soluble), 100% crystalline synthetic polymer. They absorb hundreds of times their own weight in water ranging from 10 to 800 times based on the particular grind, carrier and present aqueous fluid, and the specific manufactured base material. The CP materials used in this study were intended for use primarily as a lost-circulation material and to address near-wellbore remediation problems and reservoir architectural features needing modification by cementing zonal isolation and conformance. These materials have been used successfully to address fracture and fissure communication in wells in nearby units to stop these highly communicating fracture features from thieving the majority of injection and transmitting almost directionally into offset producers.[3]

The super-absorbent CPs currently used are sodium acrylate-based polymers, which have a three-dimensional, network-like molecular structure. The polymer chains are formed from the joining of millions of identical units of acrylic acid monomer that has been substantially neutralized with sodium hydroxide (caustic soda).[5]

Crosslinking chemicals tie the chains together to form a three-dimensional network, or 100% crosslinked system. This enables CPs to absorb water or water-based solutions into the spaces in the molecular network, forming a gel and locking up the liquid. The chemicals tie the chains together to form a three-dimensional network. This enables CPs to absorb water or water-based solutions into the spaces in the molecular network, forming a gel-like solution and locking up the liquid in suspension.

As the polyacrylamide is being developed (manufactured) under temperature, it is put into a reactor and crosslinked while still under temperature until a certain viscosity is reached. It is then run through an extruder and out onto a mesh belt where it hardens; it is then sent to the chopper where it is cut to a specific size and bagged. The crosslinked process will help keep it insoluble.

The crystallized copolymers are resistant to degradation by CO_2, bacteria, and temperatures below 250°F.[5] In addition, rigless placements can be made down current injection tubulars, which results in a savings by eliminating the need for a workover unit. If the crystallized copolymer should require removal, it can be removed by reactions from bleaches or oxidizers generally placed with a coil tubing unit.

In the current study, cement squeezes were also considered when fractures were identified as potentially very open and not tortuous. Foamed cement was selected if concerns about influxes and displacement efficiencies were noted. With a high display of influxing water, all cements could be diluted and dispersed to cause a failure.

Crystallized copolymers will start to hydrate after 20 minutes if in fresh water and at temperatures below 110°F. Use of produced brines (8.9–9.2 lb/gal) can result in a delay of around 45 minutes before the crystals hydrate; placement may be defined around this feature. Once placed into the injectant’s stream, the wells may be closed in for 30 minutes to allow the crystallized copolymers to thoroughly swell. The material will swell from 10 to 800 times its crystal weight in fresh water and 5 to 100 times its crystal weight in produced water. The wells can then be placed back on injection and analyzed for profile if desired or evaluated for pressure responses. They can also be tested for control of out-of-zone injection losses and influxes.[5]

If desired, a follow-up stimulation process can be performed to remove damage from other portions of the wellbore. Crystallized copolymer research indicates that these CPs exhibit resistance to acid, bacteria growth, and CO_2 degradation. The crystallized CP, like all CPs, may be removed on contact with oxidizers or bleach solutions whereby its backbone is broken and it becomes water-like.[5]

Treatment volumes can be adjusted per ongoing injection. Placement trials can be conducted in stages by injecting a volume of materials and displacing, then testing before final determination is made as to whether other replacement steps will be required.

When the post-placement period ends, an observed pressure decline or signs of near-wellbore losses indicates that a change in fluid loss has occurred through the fracture systems. An extended pressure decline indicates that sufficient material has been placed to stop injectivity or production from the intervals. The wells can then be placed back onto injection or production for analysis and performance testing.

PLACEMENT TECHNIQUE

Various means for placement of treatments was considered and usually based on problem identification, or diagnostic steps. While the concepts or premises for fluid control are not new, consideration of various placement techniques based on past treatments and available new methods can help in developing controls on the wells.

In this study, the technique considered for placing conformance treatments with loss-out-zone injection were performed using “bullheading” placement. Because it would use current tubulars and rely on rate/pressure determinates, rigless placement for injection of a solution was identified in the diagnostics when determining the problem.[1, 4]

Mechanical packer placement techniques can also be used if it has been determined that they would provide the best placement control. Using a packer to isolate perforations or a portion of an openhole completion into which the treatment is to be placed can provide a conditional control. Additional steps for injecting the crystals can be added based on the pressure transient fall-off rate and the amount needed in the fissures, fractures, or channels.

QUALITY CONTROL

Laboratory analysis was performed to determine the set times and viscosity performance for the CP treatments based on downhole injection temperature. The crystals were mixed with a variety of carrier fluids to determine the best one for a particular well's placement requirements. **Table 1** shows analyses results for various carrier fluids and their swelling-time ranges. To determine the capabilities of the CP to control out-of-zone losses, an extrusion analysis was conducted.

CASE HISTORY

Presented is an example of the techniques and upfront evaluations used to address "out-of-zone" losses of an injection well (**Table 2** shows the well details). Several methods and techniques used to perform rigless workovers of an injection well were developed to address the specific requirements and regulatory stipulations involved with this well. The out-of-zone injection that was selected is illustrated by the well schematic shown in **Figure 1**. The loss interval was identified by running multi-rate injection profiles using both intensity and velocity analyses with radioactive tracers. This method defined the problem and the placement requirements needed. Some of the operator's needs and desires included the ability to: (1) treat the well without having to rely on a workover unit, (2) pull the well after killing it, and (3) risk not being able to gain a packer seat following the squeeze of the loss interval. The ability to modify and control injectivities without a post-drillout or additional stimulation/perforation steps was also desired.

A treatment design was created to place a volume of CP materials into a 9.0-ppg brine water solution. The CP crystallized material was mixed with a 9.0-ppg brine water system and placed as a thin solution capable of swelling up to 25–100 times the weight of the carrier brine following a specific time at the given temperature. After placement of a selected volume in stages and then allowing sufficient time for the swelling effect to occur, pressure was reapplied. A determination was then made as to whether an increase caused by the CP crystals had effectively created a sealing barrier that might help reduce the injection of water into the loss interval and out-of-zone area.

The design was placed at an injection rate of 1–2 BPM down the injection tubing. The timed reaction for the 9.0-ppg brine solution carrying the CP crystals was based on the bottomhole injection temperature and the contact with water. Laboratory analysis indicated that the reaction usually occurs around 45 minutes before swelling initiation.

It was recommended to inject a minimal volume of 2,000 gallons of 9.0-ppg brine pre-flush. The treatment consisted of injecting 2,000 gal of 9.0-ppg brine containing 600 lb of CP, followed by 9.0-ppg brine water to clear the tubing (24 barrels). The operation was conducted as follows:

1. Treatment was pumped down the current injection string and packer; no workover unit was used.
2. The hole was loaded with 9.0-ppg brine water and then 24 bbl of 9.0-ppg brine water was pumped down tubing into the lower Paddock interval (majority of injectant going into this interval).
3. Pumped 2,000 gallons of 9.0-lb/bbl brine water containing 600 lb of CP. The CP was added on-the-fly; the product was not slugged or dumped into the brine water. The process was best handled by giving a constant pouring stream into the mixing tub through an additive device.
4. Pumped 24 bbl of 9.0-ppg brine water to displace the tubing down through the interval to be squeezed and determine the pressure response and falloff. Compared the pressure response and falloff to the initial test.
5. Shut down for 30 minutes. Prior to re-establishing injectivity on the well, operations determined whether the pressures were showing a sealing effect or possible diversion. If the pressure response had indicated that another squeeze with the CP was required, the operation would have repeated Steps 3–4.

PLACEMENT CONSIDERATIONS

The treatment was performed using placement down the current injection string and packer. Before treatment, the majority of injection was going into the bad casing interval from 5,974–5,948 ft and below 6,014 ft. It was felt that the treatment would be placed in this lower Paddock interval without much entry into the upper Paddock or the

Glorieta (see Figure 5). Difficulty acquiring a pulling unit in the Permian basin during the hectic and busy operation created a challenge. It was believed that the treatment could be applied without setting a packer between the Glorieta and upper Paddock to squeeze down below the intervals needing to be left open. There was consideration of developing a "rate-placement technique," whereby the sealing solution would be displaced down the tubing at a rate of at least 1 BPM for a set time consideration of the CP.

ANALYZING LEAKOFF OF GELS

To interpret the progressive history of a CP system while traveling down a fracture as well as a conventional polyacrylamide gel, laboratory analysis was performed. In fluid testing, use was made of a fluid loss analyzer (**Figure 2**) to gain a measure of filtration on the gels while flowing (pushed) down a permeable fracture, gaining viscosity due to filtrate extrusion. The extrusion analysis [SLIP] was performed between brass plates using a compressive strength testing device (**Figures 3 and 4**). With squeeze pressures on actual jobs exceeding 2,000–3,000 psi on the filtrated gel systems while packed off within the fractures, a substantial sheer pressure was used to determine capabilities.

CASE STUDY RESULTS

The treatment was performed in one stage, and post-treatment profile logs were run to determine whether the desired objectives had been accomplished. The loss interval was blocked and received an extended sealing deep into the formation to prevent re-injecting on subsequent flooding (**Figure 5)**.

CONCLUSIONS

Based on the successful results from work addressing techniques and methods used to control out-of-zone injection, needed changes in well condition were continued on several other wells displaying similar problems. To understand the capabilities of the CP used with fracture communications, various laboratory tests and evaluations were performed. In the case study presented, the loss interval was blocked and received an extended sealing deep into the formation. As a result, re-injection was prevented for subsequent flooding.

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Table 1
Swelling Times for Various Concentrations & Carrier Fluids (1 of 2)

Crystal Polymer Grind Size	Carrier Fluid	Concentration of CP in Carrier Fluid	Temperature, °F	Initial Swelling Time, hr:min	Final Swelling Time, hr:min	Swelling Increase, Wt.-to-Wt. Ratio
425–1000 microns	Fresh water	0.2 ppg	80	0:09	0:15	400
		0.4 ppg	80	0:09	0:15	400
		0.5 ppg	80	0:09	0:15	400
425–1000 microns	Fresh water	0.2 ppg	120	0:03	0:09	400
		0.4 ppg	120	0:03	0:09	400
		0.5 ppg	120	0:03	0:09	400
1 mm	Fresh water	0.05 ppg	80	0:14	0:20	500
		0.1 ppg	80	0:13	0:18	500
		0.15 ppg	80	0:12	0:16	550
2 mm	Fresh water	0.10 ppg	80	0:17	0:24	500
		0.15 ppg	80	0:15	0:21	500
		0.20 ppg	80	0:14	0:20	500
4 mm	Fresh water	0.20 ppg	80	0:18	0:25	500
		0.4 ppg	80	0:18	0:25	500
		0.5 ppg	80	0:18	0:25	450
4 mm	Fresh water	0.2 ppg	120	0:14	0:20	500
		0.4 ppg	120	0:14	0:20	450
		0.5 ppg	120	0:14	0:20	400
14 mm	Fresh water	0.2 ppg	80	0:20	0:30	500
		0.4 ppg	80	0:20	0:25	450
		0.5 ppg	80	0:20	0:25	400
14 mm	Fresh water	0.2 ppg	120	0:17	0:25	500
		0.4 ppg	120	0:16	0:25	450
		0.5 ppg	120	0:16	0:25	400
425–1000 microns	Brine water, 9.5 ppg	0.2 ppg	80	0:25	0:28	150
		0.4 ppg	80	0:20	0:28	125
425–1000 microns	Brine water, 9.5 ppg	0.2 ppg	120	0:15	0:25	150
		0.4 ppg	120	0:15	0:25	125
1 mm	Brine water, 9.5 ppg	0.05 ppg	80	0:16	0:30	125
		0.1 ppg	80	0:17	0:30	150
		0.15 ppg	80	0:18	0:30	125
2 mm	Brine water, 9.5 ppg	0.10 ppg	80	0:20	0:30	125
		0.15 ppg	80	0:18	0:30	150
		0.20 ppg	80	0:18	0:30	125

Table 1
Swelling Times for Various Concentrations & Carrier Fluids (2 of 2)

Crystal Polymer Grind Size	Carrier Fluid	Concentration of CP in Carrier Fluid	Temperature, °F	Initial Swelling Time, hr:min	Final Swelling Time, hr:min	Swelling Increase, Wt.-to-Wt. Ratio
4 mm	Brine water, 9.5 ppg	0.5 ppg	80	0:20	0:33	150
		1.0 ppg	80	0:20	0:30	100
4 mm	Brine water, 9.5 ppg	0.5 ppg	120	0:18	0:30	175
		1.0 ppg	120	0:18	0:27	150
14 mm	Brine water, 9.5 ppg	0.5 ppg	80	0:25	0:40	150
		1.0 ppg	80	0:25	0:45	100
14 mm	Brine water, 9.5 ppg	0.5 ppg	120	0:20	0:35	150
		1.0 ppg	120	0:20	0:35	125
425–1000 microns	Brine water, 10.0 ppg	0.2 ppg	80	0:35	0:40	125
		0.4 ppg	80	0:30	0:40	100
425–1000 microns	Brine water, 10.0 ppg	0.2 ppg	120	0:20	0:35	150
		0.4 ppg	120	0:20	0:35	100
4 mm	Brine water, 10.0 ppg	0.5 ppg	80	0:25	0:45	100
		1.0 ppg	80	0:25	0:45	50
4 mm	Brine water, 10.0 ppg	0.5 ppg	120	0:30	0:55	100
		1.0 ppg	120	0:30	0:55	50
14 mm	Brine water, 10.0 ppg	0.5 ppg	80	0:25	0:45	100
		1.0 ppg	80	0:25	0:45	50
14 mm	Brine water, 10.0 ppg	0.5 ppg	120	0:25	0:55	100
		1.0 ppg	120	0:25	0:55	50
4 mm	1 wt.% NaCl brine	4 lb/bbl	Ambient (~20°C)	0:30	0:60	300
		(11.43 kg/m^3)	Ambient (~20°C)	0:30	0:60	275
14 mm	1 wt.% NaCl brine	4 lb/bbl	Ambient (~20°C)	0:40	0:60	250
		(11.43 kg/m^3)	Ambient (~20°C)	0:40	1:20	235
4 mm	2 wt.% NaCl brine	4 lb/bbl	Ambient (~20°C)	0:45	1:45	215
		(11.43 kg/m^3)	Ambient (~20°C)	0:45	1:45	200
14 mm	2 wt.% NaCl brine	4 lb/bbl	Ambient (~20°C)	> 1 hr.	2:00	200
		(11.43 kg/m^3)	Ambient (~20°C)	1:30	3:00	100
4 mm	3 wt.% NaCl brine	4 lb/bbl	Ambient (~20°C)	2:00	4:00	125
		(11.43 kg/m^3)	Ambient (~20°C)	2:30	5:00	50
14 mm	3 wt.% NaCl brine	4 lb/bbl	Ambient (~20°C)	5:30	7:00	25
		(11.43 kg/m^3)	Ambient (~20°C)	7:00	9:00	10
4 mm	8.5 ppg $CaCl_2$	0.2 ppg	Ambient (~20°C)	13:00	24:0	10
			Ambient (~20°C)			Did not swell

Table 2
Case Study Well Details

Surface casing	8 5/8-in. 24-lb WC-50 casing at 1,530 ft
Production casing	7 7/8-in. Hole, 5 1/2-in. casing, 19 jts 17-lb WC-50, and 132 jts 15.5-lb J-55 set at 6,288 ft
Tubing	2 3/8-in. Duo-line J-55 tubing
Outer diameter	2.375 in.
Injection packer	Nickle-plated Loc-Set packer set at 5,798 ft
Injection profiles	Indicated that majority of water going out lower Paddock interval through bad casing from 5,874–5948 ft and below 6,014 ft (1,000–1,800 BWPD)

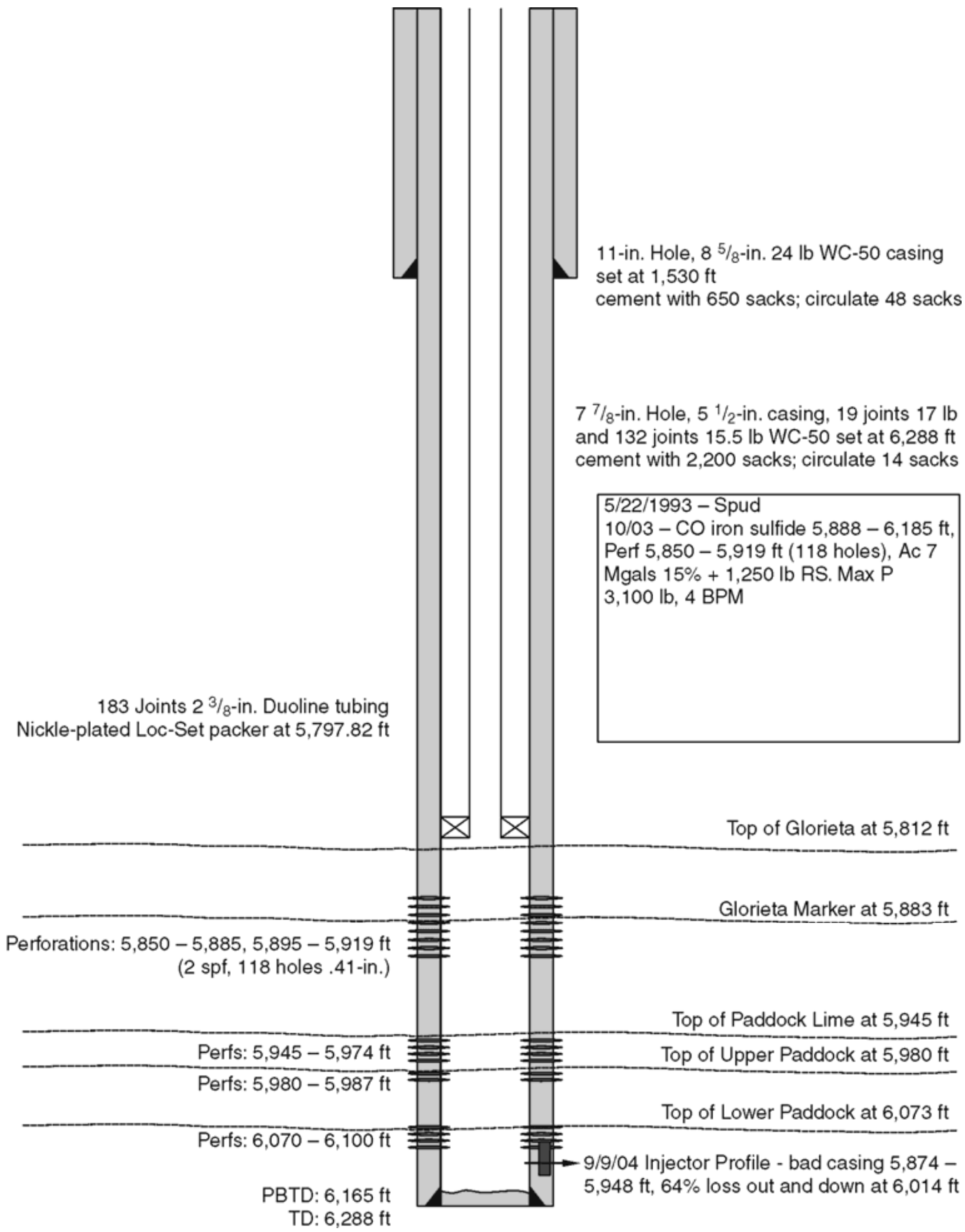

Figure 1 - Schematic of case well showing “out-of-zone” losses.

Figure 2 - Two views of the fluid loss analysis apparatus used to determine the filtration effects traveling down a fracture under pumping conditions.

Figure 3 - Two views of the compressive strength tester (0–12,000 psi) used to perform flat plate extrusion testing.

Figure 4 - Non-extruded CP following a 10,000-psi test (brass plates). CPs show extreme capability as blockage and squeeze materials resist extrusion.

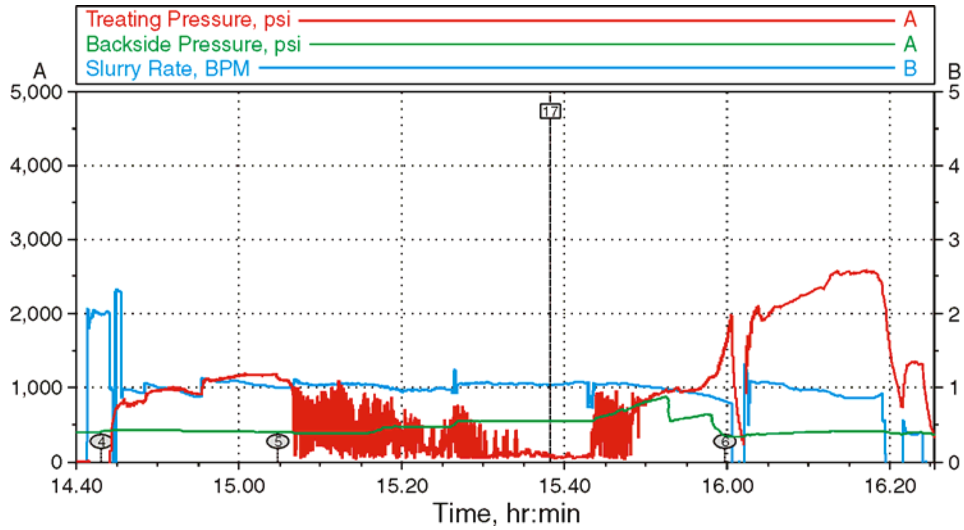

Figure 5 - Typical treatment of case well showing the impact of shutting off an out-of-zone injection.