AN IMPROVED PARTICLE-GEL SYSTEM FOR WATER AND GAS SHUTOFF OPERATIONS

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ABSTRACT
Cement squeezes have been used for many years for various operations such as casing leak repairs, sealing of thief zones, and zonal isolation. While they have been successful in many of these operations, they often require more than one attempt before success is achieved, or they are not successful at all. This paper presents the development of a system based on a combination of a porosity-fill sealant with particulates. The particulates provide leakoff control, which leads to shallow matrix penetration of the sealant. The main advantage of this system over cement is that the gel remaining in the wellbore can be washed out of the hole, and does not need to be drilled out as is the case with cement. While this system has previously been reported, this paper presents improvements in the fluid-loss system as well as additional information on case histories.

INTRODUCTION

Unwanted water and gas production is a major problem in fields throughout the world. Produced water has a major economic impact on the profitability of a field because of disposal costs, environmental issues, and reduced hydrocarbon production. Water-production problems can vary from: (1) leaks in casing, production tubing, or packers, (2) flow behind casing, (3) water coning (or water cresting in horizontal wells), and/or (4) direct communication from injector to producer through natural or induced fractures. Numerous methods are available to combat these problems, with each method having its own advantages and drawbacks. One of the earliest methods was to simply carry out a cement squeeze operation to shut off either an isolated section of a wellbore or an entire wellbore. Cement squeezes have been effective in many cases, but there are drawbacks to the system. One drawback is the need to drill out cement left in the wellbore when an entire interval is to be treated so that the productive zone can be re-perforated. This usually requires the use of a rig and is costly and time consuming. During this drillout process, cement in perforations can be damaged and the intended seal over the offending zone can be compromised, allowing water or gas to continue to flow into the wellbore.

The other main type of treatment that has been used involves the use of sealants to plug the offending zone. These are materials that can be easily mixed and pumped into the wellbore and into the rock matrix. Following a shut-in period, a chemical reaction transforms the liquid into a gel that effectively plugs the treated zone. Again, these systems have been used effectively for many years, but a drawback is that the offending zone must be isolated from the productive zones. If these sealants are allowed into a productive zone, they will damage hydrocarbon permeability and potentially completely seal the hydrocarbon zone. Thus, it is necessary to use some type of isolation technique, which can be costly and in some cases is not feasible because of the wellbore configuration.

Although unwanted fluid production has been resolved in many cases using various techniques, there are opportunities for improvement. This paper discusses a technique that uses a sealant with a particulate fluid-loss additive that limits leakoff into the formation.

DESCRIPTION OF THE PARTICLE-GEL SYSTEM

The particle-gel system (PGS) is composed of: (i) an organically crosslinked porosity-fill sealant and (ii) inert particulates to provide leakoff control resulting in a shallow and controlled penetration of the sealant. Once the filtrate, that is the porosity fill-sealant, is inside the matrix of the rock, the system is thermally activated forming a three-dimensional gel structure that effectively seals off the targeted interval. After the PGS system is squeezed in place, the well is shut in to allow the base fluid to crosslink. The system can be easily washed out of the wellbore, as compared to cement, which must be drilled out. Selective perforation of the oil zones re-establishes the desired hydrocarbon production from the targeted interval as shown in **Fig. 1**.

(i) Organically crosslinked porosity-fill sealant. The sealant system described in this paper uses either polyacrylamide or a copolymer of acrylamide, crosslinked with polyethyleneimine (PEI). This system has a temperature range from 70 to 350°F. The sealant system components are easily diluted in the mixing brine. The crosslinking process is activated by the temperature of the well. The crosslinking rate is dependent upon temperature, salinity, pH, and base polymer and crosslinker concentrations. The sealant system offers the following advantages:

- Low-viscosity fluid system (20 to 30 cp) that can be easily injected deep into the matrix of the formation without undergoing hydrolysis and precipitation. It is well known that chrome-based systems tend to hydrolyze and precipitate, especially with increasing pH and temperature (Lockhart and Albonico 1992).
- Adequate pumping times in environments up to 350°F (177°C) to obtain adequate placement time before the system undergoes the phase change from liquid to a three-dimensional gel structure. This transition time is completely controllable and predictable with the crosslinker concentration for a given temperature. **Fig. 2** shows a typical viscosity vs. time plot for this system. The inflection point of this plot corresponds to the gelation time of the system.
- Effective water permeability and gas permeability reduction and sufficient strength for resisting drawdown pressure inside the wellbore and stopping water and gas flow. The system provides sufficient strength for resisting differential pressures of at least 3,600 psi (based on laboratory data).
- Thermal stability tested up to 375°F (191°C).

In addition, the sealant system is not sensitive to formation fluids, lithology, and/or heavy metals. This system has been used throughout the world in a wide variety of applications (almost 500 jobs performed), and a previous paper summarized both laboratory data and a number of case histories for both water and gas shutoff (Eoff et al. 2006).

(**ii) Inert Particulates.** In the original formulation of the PGS system, cement was used as the particulate material (van Eijden et al. 2004). The idea was to have both a hard-setting material such as cement, as well as the filtrate, which would gel and aid in blocking fluid flow. A few jobs were performed with this combination but later on it was decided to replace cement with inert particulates, mainly because of the following reasons: (1) chemical interaction of the sealant system with cement would change the setting times of both systems, and (2) sealant/cement volume left in the wellbore would have to be drilled out (van Eijden et al. 2005). It was then decided to investigate different inert particulates that would not change the activation time of the organically crosslinked porosity-fill sealant and would allow easier wellbore cleanup. A variety of inert particulates were evaluated and provided excellent fluid-loss control properties without changing the activation time of the sealant system. Some of the evaluated inert particulates are: silica flower, calcium carbonate, starch, and a water swelling polymer (Abbasy et al. 2008), among others.

Currently, silica flour is the inert fluid-loss additive of choice for the PGS. About 100 jobs have been performed with this system to date. **Fig. 3** illustrates that the addition of the silica flour to the sealant has only a slight effect on the gel time of the system (neat sealant vs. filtrate for the PGS system). Therefore, the only design criteria for this system is to determine the gel time of the sealant formulation, which is based on the temperature and amount of time needed to place and squeeze the treatment.

LABORATORY EVALUATION OF THE PGS SYSTEM

The initial laboratory work carried out to prove the ability to provide leakoff control and an adequate seal was conducted using cores (3-in. length and 1-in. diameter) in Hassler sleeves. Representative data from this testing are shown in **Table 1**. The cell was modified such that the PGS slurry could be spotted to the core face and pressure applied to allow filtrate leakoff. In these tests 500 psi differential pressure was applied for 30 minutes, followed by an overnight shut-in to allow filtrate gelation. The following day, brine was pumped against the opposite core face.

The variables investigated were temperature, permeability, and percent silica flour (measured as % by weight of the total mixture). As shown, the amount of leakoff and the pressure required to initiate flow of the brine was independent of the temperature or the core permeability. However, the percent silica flour did influence the amount of leakoff seen. The formulations containing 50% silica flour had an average total leakoff of 13 mL. The formulations containing 35% silica flour had an average leakoff of 63 mL. Therefore, 50% silica flour was chosen for field usage. Another factor was that with 50% by weight silica flour, the resulting slurries did not show any settling of the solids. As the percent silica flour was reduced, major settling did occur. Note that in most of the tests, 1,000 psi or greater differential pressure was applied to the cores with no resulting flow of brine. In two cases, brine flow was seen at differential pressures less than 1,000 psi, but the calculated permeability reduction was higher than 99%. In other testing, this system has been successfully tested to withstand a differential pressure of at least 2,500 psi.

Several successful jobs were pumped using the formulation with 50% by weight silica flour. However, there were at least two drawbacks to this formulation. First was the amount of silica flour being used, which presented handling and hazard concerns (from the silica flour dust). Another issue was that this formulation offers no flexibility in changing the leakoff properties of the slurries. Therefore, further investigation was carried out on alternate fluid-loss systems.

The system that was chosen maintained the use of silica flour as the inert particulate, and included the use of a viscosifier to keep the sand suspended. The viscosifier is a natural product that also works synergistically with the crosslinker to provide additional fluid loss control, an unexpected benefit. In this investigation, fluid-loss tests using standard mud/cement equipment were used to determine leakoff properties of the slurries. In these tests, synthetic core material was used as the filter medium, to mimic leakoff into a rock matrix.

Fig. 4 shows data from four of these tests. These tests were run for 10 minutes at 500 psi in the synthetic core material with an average pore throat size of 10 microns. Two of these tests were run at 190°F and two at 250°F. In this core material, the original formulation, with 50% by weight silica flour, blew out all of the liquid in less than 10 minutes (100 mL was the maximum amount of fluid that could leak off in these tests). The formulations using 50% silica flour correspond to approximately 6,000 pounds of silica flour per 1,000 gallons of slurry. In the second test shown, dropping the silica flour to 25 lb/Mgal along with 25 lb/Mgal of the viscosifier also blew out all the liquid in less then 10 minutes. However, increasing the silica flour to 50 and 500 lb/Mgal allowed the test to run the full 10 minutes, with lower leakoff with the 500 lb formulation. This is an example of only a small amount of the testing that was run, but illustrates that changing the level of silica flour can affect the amount of leakoff. In addition, lower levels of leakoff have been seen with the silica flour/viscosifier formulations than with the original formulation.

Table 2 shows rheological data for a formulation with 50% by weight silica flour and a formulation with 25-lb/Mgal silica flour plus 25-lb/Mgal viscosifier. As shown, the formulation with the viscosifier was significantly lower in viscosity, although it also shows better leakoff control with no settling of the sand.

PGS DESIGN GUIDELINES

The overall design of PGS treatments is similar in many ways to a cement squeeze treatment. Enough fluid is placed to cover all open perforations plus roughly 10% more to allow for leakoff during the squeeze. Once the fluid is placed across the open perforations, a hesitation squeeze operation is performed in order that the sealant base-fluid penetrates the matrix of the rock. The maximum treating pressure is chosen to remain below the formation-parting pressure.

Although it is not required, it is recommended that the crosslink time of the base fluid be similar to the total placement/squeeze time. Experience has shown that sealant treatments provide better, more complete seals if the final treatment stages are gelling while being placed. This can present the risk of not getting all the treatment placed before placement pressures exceed reservoir parting pressures (or worse, not getting the gel out of the tubing); however, the crosslinking of the base fluid in the PGS is highly predictable, so premature gelation is not considered to be a major risk. After the PGS plug is squeezed in place, the well is shut in to allow the base fluid to crosslink. Then, the set PGS remaining in the wellbore is washed or jetted out so that pay intervals can be re-perforated as shown in Fig. 1.

CASE HISTORIES

To date, over 100 jobs have been run with the PGS to cover a wide variety of conformance problems for both water and gas shutoff. A few case histories are described here.

Well 1. In an offshore well, pressure and well fluid from the reservoir were in communication through a pipe-in-pipe annulus (Bewick et al. 2007). Consideration was given to using a cement slurry to provide a seal. However, this option was discarded because of the potential of microannulus formation that might be created by cyclical temperature loading on the tubing. A decision was made to use the PGS system to provide a permanent barrier between the tubing/packer and the annulus. Following the treatment, the annulus was vented to 0 psi. Then the tubing was pressured to 200 psi and held for 10 minutes. No communication was seen. Following the treatment, no increase in annulus pressure was observed. Before the treatment, there was a continuous rise in pressure, even when the well was shut in.

Well 2. An oil well was completed in three different zones (sandstones) and was producing 3,000 BFPD with 63% watercut. After running a production logging tool (PLT), there was evidence that the middle sands were flushed and producing predominantly water. Wellbore completion did not provide straightforward options for zonal isolation, so the well was selected for a PGS treatment to shut off all perforations followed by re-perforation of the upper and lower zones. The PGS treatment was bullheaded into the wellbore; squeeze pressure was applied (maximum of 1,500 psi) for 30 minutes. The well was then shut in for 48 hours followed by the wellbore cleanup stage. Subsequently, the upper and lower zones were re-perforated yielding an initial production of 4,500 BFPD at a 40% watercut. A PLT showed no flow from the middle zone.

Well 3. In this well a PLT indicated that one zone was producing the majority of water (van Eijden et al. 2005). The PGS system was spotted over this zone with coiled tubing and approximately 1,800 psi overbalance was applied. After washing out the material in the wellbore, another PLT indicated that the treated zone was completely sealed.

Well 4. In addition to providing a controlled and shallow penetration, the PGS system has been used as a tail-in of the organically crosslinked porosity-fill sealant when dealing with highly fractured and low-pressure formations to avoid overdisplacement of the main system. This was an offshore oil well producing from a highly naturally fractured formation with a high watercut (caused by coning) with BHT of 280°F. It was decided to isolate the current perforated interval (~100 ft) and re-perforate a few feet higher. The organically crosslinked porosity-fill sealant was pumped to form a barrier deep inside the matrix of the rock to effectively stop the coning. This treatment was tailed-in with 20 bbl of the PGS to avoid overdisplacement of the main treatment (a positive pressure increase was observed at surface when the PGS arrived to the perforations). Following the treatment, the well was shut in overnight. Because of the nature of these reservoirs (highly naturally fractured), the top of the treatment left in the wellbore could never have been tagged during the cleanup stage in previous treatments. In this particular job, they were able to tag the top of the treatment (the PGS) in the wellbore for the first time. In addition, the interval was effectively sealed.

Drilling Applications. The PGS has also recently been used as a lost-circulation material for drilling applications. In a recent job, the system was pumped through drillpipe and static losses were reduced from several barrels per hour to zero, allowing drilling to proceed.

CONCLUSIONS

- The PGS combines an organically crosslinked porosity-fill sealant (based on a copolymer of acrylamide and t-butyl acrylate crosslinked with polyethyleneimine) with non-cement particulates to provide leakoff control, resulting in a shallow and controlled penetration of the sealant.
- An ideal candidate well for the PGS treatment is one in which the water layer must be segregated from the hydrocarbon layer to prevent communication beyond the minimally penetrating damage. This segregation can either be caused by a non-permeable barrier separating the layers or merely by long separations between intervals.
- During the cleanup stage of the PGS treatment in the wellbore, this system can be easily washed out, as compared to cement, which must be drilled out. Selective perforation of the oil zones re-establishes the desired hydrocarbon production from the targeted interval.
- To date, more than 100 jobs have been performed with this system for water and gas shutoff applications.

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TABLE 1—CORE DATA

Temp.	Core Brine Permeability	% Silica Flour by Weight[1]	Fluid Loss (mL of Filtrate at Given Time in Minutes) Spurt	1	2	5	10	30	Pressure Applied to Initiate Flow, psi
190	144	50	2.8	6.1	7.2	8.3	9.2	11.6	1,000[2]
190	128	50	3.1	6.6	8.2	9.1	9.8	11.8	1,000[2]
190	92	35	5.8	12.8	18.7	32.0	46.0	55.5	1,000[2]
190	128	50	2.2	5.2	8.1	10.6	11.4	13.4	1,000[2]
190	101	50	0.1	0.9	2.0	4.2	7.0	9.5	471[3]
190	3,115	50	2.5	6.0	8.5	10.0	10.8	13.0	1,165[2]
230	119	50	3.5	8.7	9.3	10.6	12.0	18.0	1,000[2]
230	105	35	6.1	15.3	23.8	42.2	55.5	71.0	1,000[2]
260	124	50	5.0	7.0	8.6	10.0	12.5	17.0	1,000[2]
260	121	35	8.2	20.0	33.0	41.0	47.0	62.0	571[3]
260	63	50	1.5	5.1	8.5	9.8	11.2	14.1	1,271[2]

TABLE 2—RHEOLOGICAL DATA

Fluid-loss Additive	Fann 35 Dial Readings 600	300	200	100	60	30
50% by weight silica flour	232	121	85	43	25	15
50 lb/Mgal silica flour, 25 lb/Mgal viscosifier	76	43	31	16	11	7

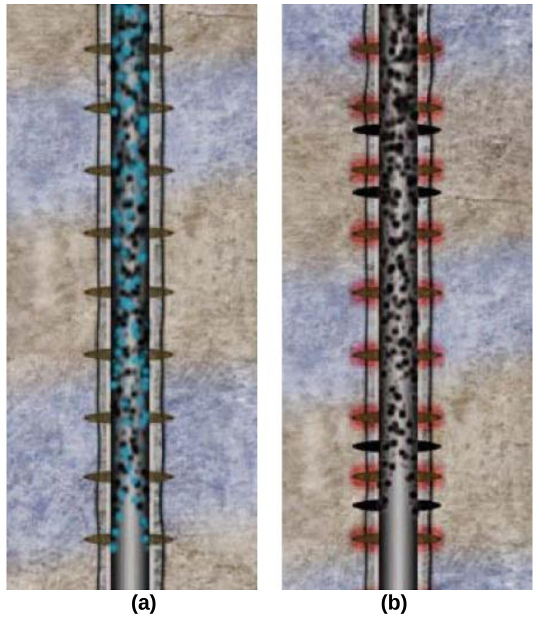

Figure 1—PGS application: (a) before: water and hydrocarbon are produced, (b) after: the PGS slurry is bullheaded into the wellbore, only the hydrocarbon intervals are re-perforated and production resumes virtually water-free.

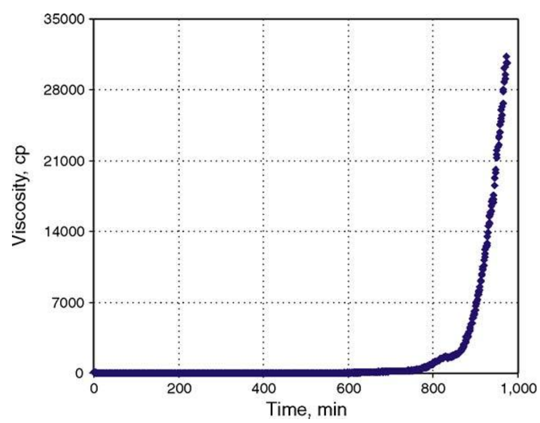

Figure 2—Typical gelation time curve for the organically crosslinked polymer (OCP) system using a Brookfield viscometer (at 185°F).

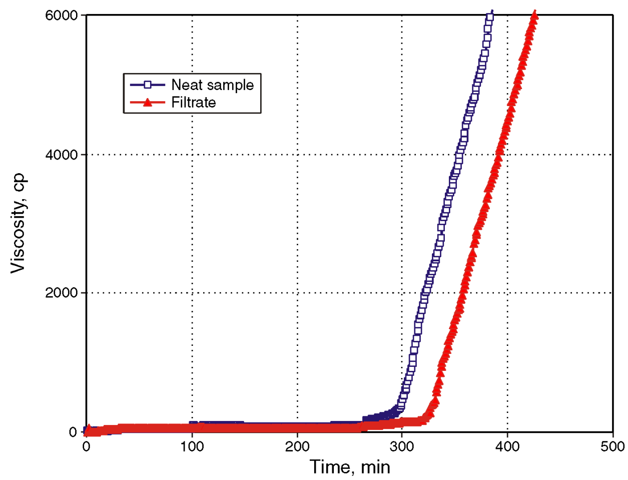

Figure 3—Gel times: neat sealant system vs. filtrate from the PGS.

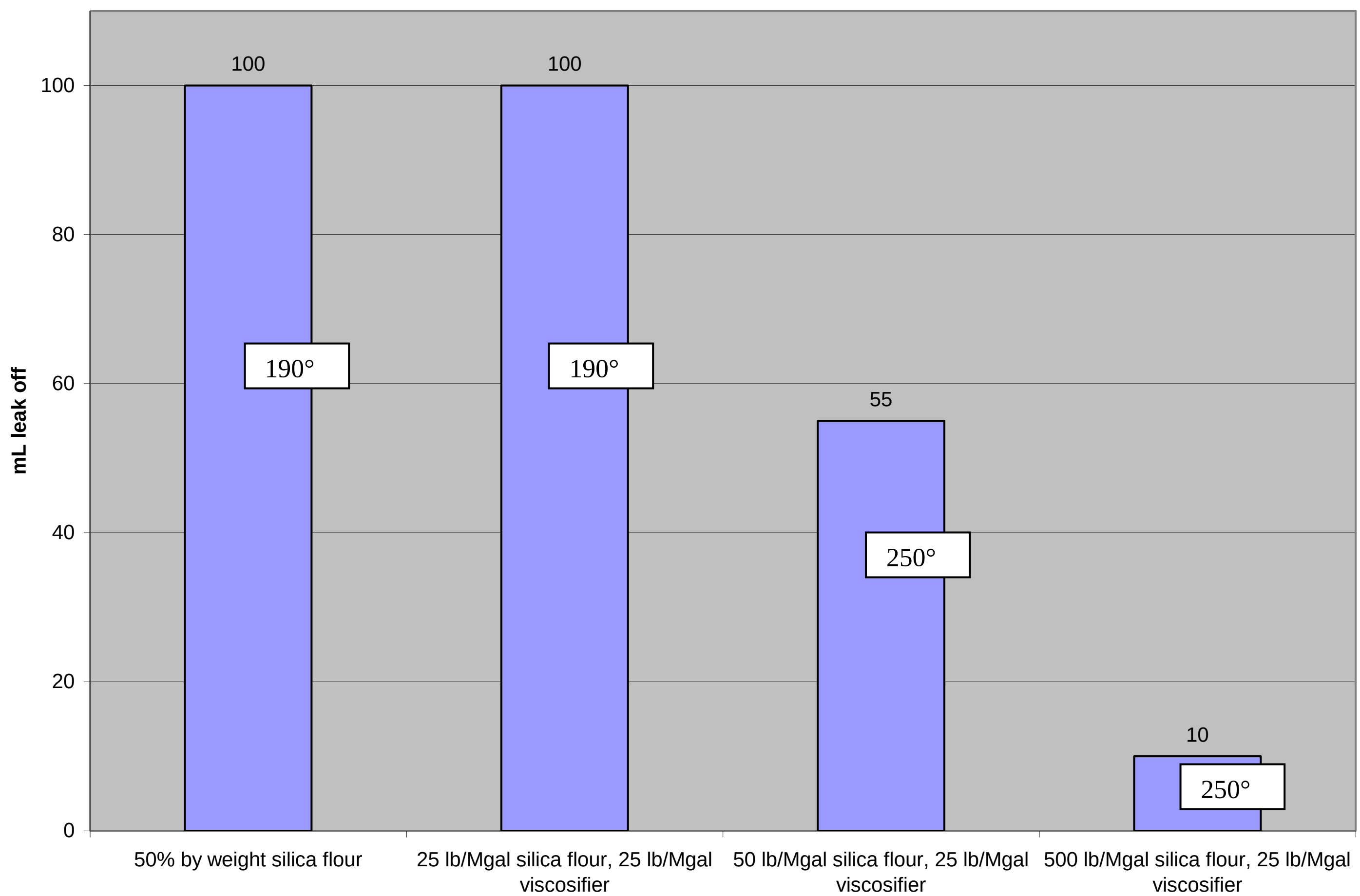

Figure 4 – Fluid loss tests on 10 micron synthetic disk. Formulations included sealant system plus particulates as shown.