Reducing Scale Buildup in Waterflood Operations

Careful attention to scale inhibition during the first wave of water injection can reduce your headaches for the long term

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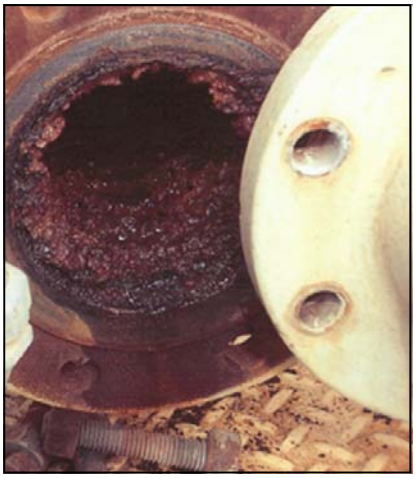

Waterflood is a major secondary recovery option for maximizing field production and ultimate oil recovery. Scaling however, is a problematic issue, hindering secondary recovery by forming blockages that can plug vital waterflood components.

Scale has a large tendency to form immediately around the water injector completions due to the mixing of injected brine and formation brine. This is especially true during initial water injection and startup, before the formation water is fully swept away from the completion.

Scale that forms at the injector causes more concern than reservoir scale formation, because at the injector large volumes of processed seawater are being forced through a relatively small, fixed space. Hence, the presence of deposited scales at the injector is more detrimental to the system than scale dropout in the larger reservoir.

Many waterflood systems utilize a two-stage Sulfate Removal Unit (SRU) to reduce seawater sulfate to levels less than 40ppm. However, the reduction of sulfate ion concentration, while reducing the sulfate scale mass and supersaturation, does not completely eliminate sulfate scale and has no impact on calcium carbonate scaling tendencies.

This was verified during scale modeling of a typical Gulf of Mexico (GoM) field undertaken by GATE in 2005. Results show that low sulfate seawater (SO_4<40ppm) injected into a typical GoM reservoir exhibits possible scale deposition until the brine mixture reaches 60% low sulfate seawater. As expected, the results also show that any drop in reservoir pressure will increase the risk of scale deposition. The risk of calcium carbonate was reduced over similar facilities in this particular case because the stripping gas method used for deoxygenation lowered the pH of the injection water to approximately 6.5, resulting in increased compatibility with the formation water in comparison to vacuum stripping or nitrogen stripping applications.

To maintain injectivity and avoid the risk of deferred production due to scale formation at the water injection completion, supplementary scale control is needed.

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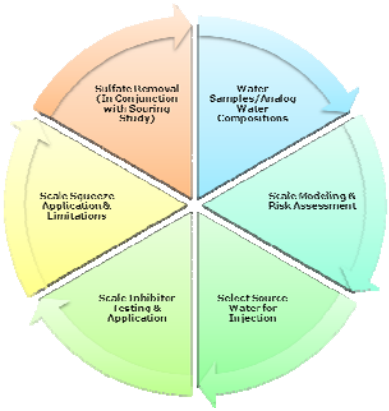
Waterflood Scale Management Checklist



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Temporary Chemical Injection

GATE waterflood project experience with major operators in the GoM and West Africa is that the injection water is initially treated with scale inhibitor at the surface. It is only necessary to treat the first 300,000 to 1MM barrels of water injected to each well, because after that most, if not all, of the formation water is swept out away from the injection completion into the reservoir. Table 1 provides a simple guide of suggested first wave water injection volumes and scale inhibitor injection concentration for different levels of scaling risk.

Scaling Risk	1st Wave Water Injection Volume (BWPD)	SI Injection Concentration (ppm)
LOW	300K - 500K	20 - 35
MODERATE	500K - 600K	35 - 50
HIGH	600K - 1MM	50 - 100

Table 1: Suggested guidelines for waterflood temporary scale inhibitor injection

Project 1, a FPSO located on the coast of West Africa with no SRU, treated injection water with 20ppm of inhibitor for a first wave volume of 500,000 barrels per injector. Project 1 currently has a total of 7 water injectors and has experienced no significant scale formation around these injectors.

Project 2 is a TLP located in the GoM. The approach by Project 2 used only 300,000 barrels per injector for the first wave of low sulfate seawater injection at a rate of 25ppm. Project 2 has experienced no scaling problems at the injectors thus far.

The Forties Field on the UK Continental Shelf, operated by BP, is comprised of 52 production wells and 4 platforms. The Forties Field does deoxygenate the seawater, but does not utilize an SRU. BP added 30ppm of scale inhibitor to the injection seawater for the first 450,000 barrels following the commissioning of each new injector. Seawater injection began in December 1976, and no scale problems around the injectors have occurred to date. Both polyacrylate and phosphonate type scale inhibitors were used for this purpose.

Conclusion

It is clear that removing sulfate (SO_4<40ppm) from the injection water via the SRU does not fully mitigate the tendency or deposition of scale in the water injection wells in all cases. Additional steps must be taken to limit scaling, especially during initial water injection and startup. Major operators in the industry treat the first wave of injected water with scale inhibitor prior to injection. The scale inhibitor treatment is a relatively low cost approach to mitigating potential damage to water injection wells. Projects referenced in this study that used this scale management approach have not experienced any problems due to scale deposition.

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