

Novel strategy to Control the Elevated Drizzle Scale in Chemical EOR Pilot with Unfavorable Harsh Environment of Giant Sandstone Reservoir in North Kuwait

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Extended abstract

This sandstone reservoir is highly heterogamous due to amalgamated tidal influenced distributary channels and has an unfavorable harsh environment for the chemical EOR such as high divalent ions (~19,000ppm) as Ca⁺⁺/Mg⁺⁺, high salinity (~280,000ppm), high temperature (~200degF) and active aquifer. After a robust lab ASP (alkaline-surfactant-polymer) formulation design and successful field trial of SWCTT (single-well-chemical-tracer-test), an inverted 5-spot injection pattern ASP pilot was designed and field execution started. However, this pilot is having a challenge to control elevated drizzle inorganic carbonate scale at the producers. This paper elaborates on novel practical strategies to control elevated scaling risks and re-optimization of ASP formulation adjusted to temperature variations due to extended softened-water pre-flush phase.

To avoid anticipated drizzle scaling, an extended softened-water pre-flush phase (over-flush) as 7PVI (pore volume injection) was planned. However, it increases pilot duration, significant soft water injection cost, reservoir cooling in the pilot area and still shows high carbonate scaling in the producers. In view of this, various novel pre-flush operating strategies are explored using high-resolution numerical simulations in the commercial chemical EOR simulator. The strategies ranked and the best one selected based on minimal divalent ion production to control scale. An over-flushing strategy in the pre-flush phase resulted in significant cooling of the reservoir prior to ASP injection as seen from thermal simulation. However, the lab testing shows serious concerns about the effectiveness of the originally designed ASP formulation due to cooling effect. Therefore, careful re-tuning of the ASP formulation was carried out to make it robust for temperature variations and the unfavorable harsh environment of the reservoir.

The selected novel pre-flush strategy result shows that using high viscous polymer slug injection (~0.6 to 0.75PVI) with over-flush injection (~1.5PVI) and maintaining VRR>1.5 controls the elevated drizzle scale in ASP Pilot under harsh environments. This strategy not only controls the scaling risk but also provides better oil desaturation, better oil chemical ratio, less cooling effect and reduces pilot duration (there by cost) as compared to the originally designed pre-flush strategy (7PVI). The re-optimized robust ASP formulation shows effectiveness in large temperature variations and the harsh environment of the pilot.

Keywords: Chemical EOR, mitigation of anticipated drizzle scaling, pre-flush strategy, reservoir harsh environment

1. Introduction

ASP flooding is one of the most attractive chemical enhanced oil recovery (EOR), which can achieve incremental oil recovery factors up to 33% in the field tests [Wang et al. 2013]. So far, ASP field tests were successful in China, India, Canada, and the USA. [Olajire 2014]. For

example, successful alkaline-surfactant-polymer (ASP) flooding in field pilot tests (in the USA, India, and Venezuela) and full field deployment in the Daqing oil field (China) show 21.4–23.24% OOIP oil recovery over water flood. However, unsuccessful cases were not rare; even in the Daqing Oil Field, where thorough research into ASP flooding has been conducted for more than 30 years, some projects achieved only partial success due to scaling, pump failures, low injectivity, corrosion, incomplete polymer dissolution, polymer degradation, and chemical effectiveness problems [Bataweel and Nasr-El-Din, 2011a; 2011b]. The main problem found in ASP technology is implementation in harsh reservoir environments like high salinity, high divalent ions, and high temperatures. The most noticeable problems with ASP technology deployment in the field are the deposition of silicate scale, chemical effectiveness, polymer viscosity reduction, and polymer precipitation [Wang et al., 2004; Stoll et al., 2011; Karazincir et al., 2011].

After ASP formulation was successful through laboratory and Single Well Chemical Tracer Test (SWCTT), an ASP pilot is designed and set to be implemented in the high-quality Z46 channel of Kuwait's clastic Raudhatain Zubair reservoir (RAZU) in a harsh environment to mitigate the above problems. In the subject reservoir, the formation water has very high salinity (>258700), divalent ions (>15800 ppm Ca⁺⁺ and 3530 ppm Mg⁺⁺), and temperature with active, strong edge aquifer drive. In ASP technology, the alkali injection in the presence of high divalent ions is the serious killer of ASP technology due to the formation of inorganic scale. Thus, the maturation of the ASP technology requires overcoming inorganic scaling hurdles for pilot-scale and commercial deployment [Lo et. al., 2011; Guo et. al., 2019]. Generally, the softened water pre-flush can be an effective strategy to maximize the efficiency of the designed ASP formulation. While this strategy does not eliminate the risk of inorganic scaling in the well bore completely because it is controlled by the production of divalent ions from the zones that are accessible by the injected softened water. In addition, the aquifer support has a strong impact on the effectiveness of softwater injection, a key enabler for the success of the RAZU ASP Pilot. Hence, the objective of this article is to present some unique challenges and discuss practical strategies to mitigate the risk of scaling concern through optimization of the pre-flush phase (before ASP slug injection).

2. Reservoir and simulation model description

The subject field (Raudhatain) is a giant anticlinal structure on-shore field in North Kuwait with multiple stacked carbonate and sandstone reservoirs. The pilot is in Zubair reservoir (RAZU), which is subdivided according to rock quality (ssand and shale ratio) and fluid properties as Lower Zubair Sand (LZSD), Middle Zubair Sand (MZSD), Upper Zubair Sand (UZSD), and Upper Zubair Shale (UZSH) [Hussain et. al., 1999]. While deep (>9500+ ft.) UZSD channel sand is a high-quality reservoir having permeability of more than 1000 mD, it is a key production zone with light oil (API Gravity 30-32), high temperature (>90°C), and very high formation water salinity (>260,000 ppm). In addition, this high salinity formation water contains very high divalent ion concentrations (16,000 ppm Ca⁺⁺ and 4,000 ppm Mg⁺⁺). This UZSD is a developed reservoir with water drive from aquifer support and peripheral water injection. The EOR target reservoir Z46CH belongs of UZSD to tidal-influenced distributary channel and estuarine channel fill. We find broadly two classes of facies associations based on the sedimentological study of cores. The upper part of the 46CH channel shows relatively clean sandstone with 0 to 5% clay content, while the lower part is composed of argillaceous bioturbated sandstone with 10–30% clay content. Currently, this channel (pilot area) is flooded by water and at residual oil saturation of approximately 20–30%, which was confirmed by the full field history matched model as well as several real field data. Previous SPE publications have discussed the evolution of a lab-optimized ASP formulation [Al-Murayri et. al., 2019a] for SWCTT and the optimization of the original chemical formulation post-SWCTT [Al-Murayri et. al., 2018]. The polymer injectivity and chemical adsorption evaluations are presented by Al-Murayri et al. (2019b), and a fit-for-purpose modeling study to support the pilot design was previously discussed by Al-Dhuwaihhi et. al. (2017).

The simulation model was extracted from full-field history-matched dynamic and static models. Then, the sector model was upscaled in areal direction away from the pilot pattern or the sector boundary through dynamic amalgamation functionality to speed up the processing time as shown in Figure 1. While the sector model was not upscaled vertically to maintain layer heterogeneity and capture proper fluid flow movement in the EOR pilot.

Mercury air capillary pressure data and geological description were used to define facies (clean sand, silty claystone, and fine sand). The connate water saturation was in the range of 0.05 to 0.15 for clean or silty sand with 0.3 end-point of water relative permeability at residual oil saturation after water flood from forced imbibition by centrifuge experiment. The centrifuge experiment was unable to determine the Corey exponent in multi-Darcy rock; hence, it assumed a typical value in the range of 2.5 to 3 for sandstone. The water flood relative permeability curves were used for three-rock types, while the chemical relative permeability curve was utilized from the ASP core flood. The pilot area is at residual oil saturation; therefore, the sector model was initialized using current water saturation after matching liquid trapper core, open-hole logs, SWCTT, and bottom-hole sample (MDT). The current pressure gradient range is 0.48–0.49 psi/ft. around the pilot areas as per recent RFT/MDT. These current water saturation and pressure have a good quality match with the full field history-matched model; therefore, the flux boundaries were extracted from the full field around the sector as influx and outflow data.

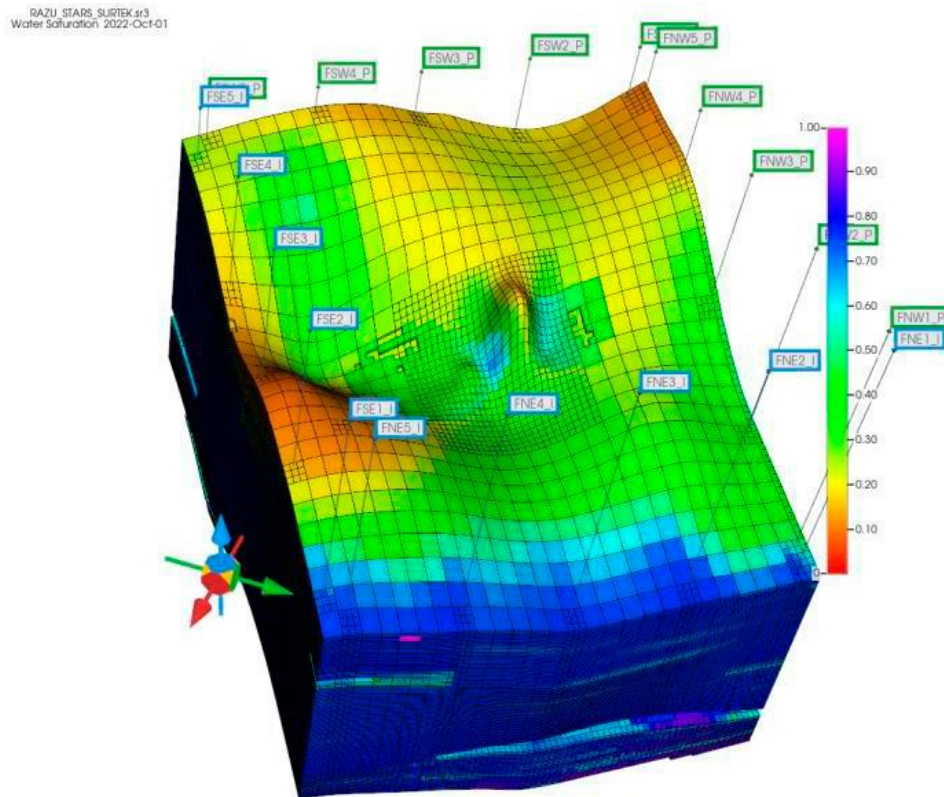


Figure 1: RAZU Pilot model showing fine and upscale grids

3. Results and Discussions

3.1 Scaling Potential and scale formation mechanism in ASP flooding

In the ASP flooding, the reaction of alkali with the rock increases the concentration of scale formation ions such as $(\text{SO}_4)^{--}$, $(\text{CO}_3)^{--}$, $(\text{SiO}_3)^{--}$, Ca^{++} , Al^{3+} , Mg^{++} , and $(\text{OH})^-$. The alkali (with pH 11) dissolves silica from quartz [Sonne et al., 2012]. This dissolved silica has a tendency to become stable in high-pH environments. When ASP flow reaches a well or is near a wellbore, then ASP high pH fluid mixes with neutral pH connate water and neutralizes ASP high pH, thus reducing the pH of alkaline water. Due to pH reduction, the polymerization of dissolved silica occurs and forms colloidal silica nanoparticles [Arensdorf et al., 2011]. It is known that the formation of calcium carbonate (CaCO_3) scale is largely determined by pressure, pH, temperature, and the concentrations of calcium and carbonate. The magnesium will precipitate as $\text{Mg}(\text{OH})_2$, and the amorphous magnesium silicate will form due to bridging the colloidal silicate particles with magnesium ions. The colloidal silicate particles start to continue growing in the absence of divalent ions, which results in the formation of amorphous silica scale [Arensdorf et al., 2011]. The solubility of CaCO_3 decreases with increasing temperature and reducing pressure, thus resulting in increased scaling tendencies and subsequently a potential increased scale mass.

3.2 Polymer precipitation and viscosity reduction risks in presence of divalent ions:

Ward and Martin (1981) present detailed work for the influence of divalent cations on the viscosity of hydrolyzed polyacrylamides. The relationship between fraction of viscosity retained with fraction of divalent ions (Ca^{++} and Mg^{++}) for HPAM type polymer clearly shows that the increase in hardness can reduce more than twice the viscosity of the polymer. From a practical point of view, the presence of divalent ions also has other drawbacks, such as polymer precipitation [Ward and Martin, 1981].

3.3 Scaling risk due to active aquifer toward ASP pilot

The historical UZSD production and injection data in the vicinity of the EOR pilot is represented in Table 1. Tank model (Mbal) simulation suggests that production could not be sustained without adequate aquifer support to maintain current reservoir pressure (3800 psi), i.e., only decline less than 900 psi pressure from the original reservoir pressure as shown in Figure 6. In addition, the full field history-matched model also suggests that two strongest aquifers are connected to UZSD, including target Z46CH of the UZSD system. That translates to a significant water influx into the pilot area from the north-east and from the south-east sides. Water and oil are leaving the Pilot area as outflow mainly from the Southwest and to some extent from Northwest directions, as shown in Table 2. Currently, outflow from the pilot sector is mainly from the SW direction, and influx into the sector is from the NE and SE directions. Therefore, in the ASP flooding, there is a high possibility of formation water coming back (i.e., high divalent ions) towards the pilot after soft water injection in the pre-flush; this can cause serious scaling issues in the ASP pilot. Therefore, the flux from the full field model was used as input to the sector model with equivalent pseudo-water injection to maintain the pressure regime. Therefore, there is huge risk of scale formation due to active strong edge acquirer due to influx of formation water toward the EOR pilot area.

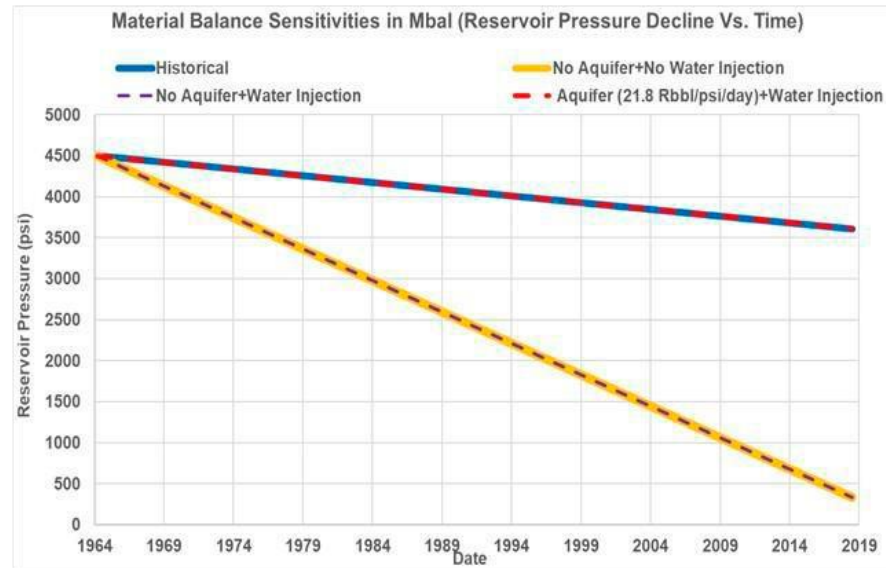


Figure 2: Results of material balance tank model from Mbal simulation

Table 1: Influx and outflux across the sector model near to RAZU EOR Pilot (UZSD-3km range)

Cum. Oil Produced, MM Rbbl	Cum. Water Produced, MM Rbbl	Total Liquid Produced, MM Rbbl	Total water Injected, MM Rbbl
356.7	37.1	393.7	9.4

Table 2: Influx and outflux rates at the Pilot sector boundaries

Flux around the boundary of Sector Model									
Direction of Flux	Cumulative Flux, MMSTB				Last 6 months average flux rates, STB/D				
	Influx to the Sector		Outflux from Sector		Influx to the Sector		Outflux from Sector		
	Oil	Water	Oil	Water	Oil	Water	Oil	Water	
NW			1.8	5			11	135	
NE	2.6	20.5			1.6	2444			
SE	5.2	4.2			0	763.8			
SW			13.6	11.6			57.3	2864	

3.4 Risk Mitigation Strategies for ASP flooding Technology implementation in the field

Below was the strategies used to mitigate scaling and other risk for ASP flooding technology implementation in the field:

3.4.1 Polymer selection strategy in harsh environment

Temperature has a significant effect on polymer stability [Seright et al. 2010; Levitt et al. 2011], and it is more difficult to apply chemical flooding in high-temperature reservoirs [Seright and Skjevrak 2015; Wan and Seright 2017]. The subject reservoir has very high temperature (200deg F) and high divalent ions (15800 ppm Ca⁺⁺ & 3530 ppm Mg⁺⁺). Therefore, there is a high risk of polymer precipitation and hydrolysis to reduce viscosity at elevated temperatures and hardness. As in the optimized case, the temperature and divalent ions were still very high in this pilot. As shown in Figure 3, the cloud point of the polymer increases by increasing the percentage of ATBS-type molecules in the polymer. The laboratory study shows that the polymer containing 20% ATBS reduces the hydrolysis and precipitation changes in this reservoir. However, under harsh conditions, the AN125 ATBS co-polymer is more resistant to hydrolysis than the FP5115 and FP5220 polymers, but at higher cost and lower solubility. To account for both the expected degree of hydrolysis e and good solubility in a solvent containing a co-solvent, polymer containing ~ 20% ATBS, ~ 15-20% AA and ~ 60% AM is recommended for RAZU reservoir.

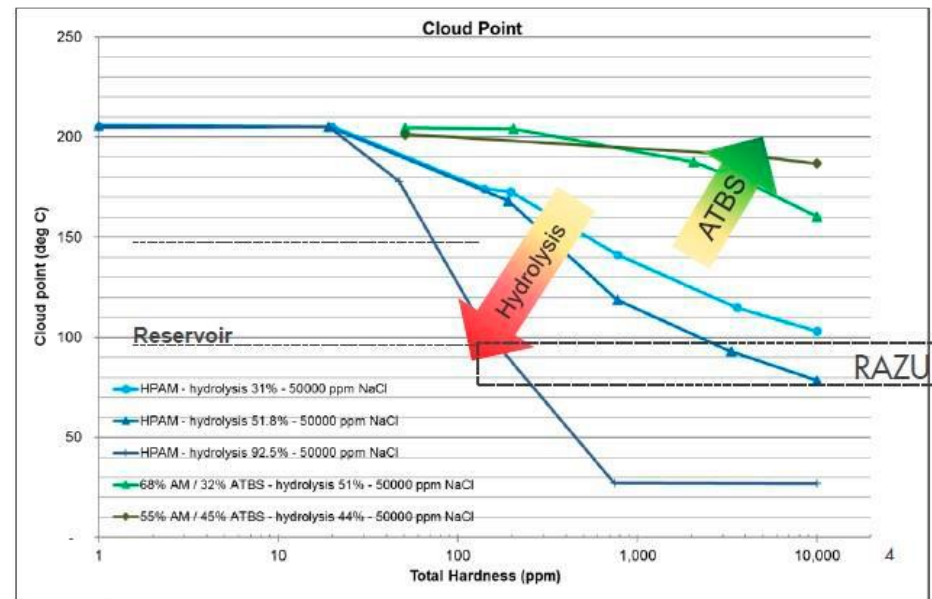


Figure 3: Cloud point temperatures as a function of hardness (in mM) for HPAM and ATBS polymers [Doe et al., 1987; Moradi-Araghi and Doe, 1987; Moradi-Araghi et al., 1987].

3.4.2 Scaling Mitigation Strategies in harsh environment

Selection of pump type in artificial lift: The antiscaling progressing-cavity pumps (PCPs) and electrical submersible pumps contributed to success of ASP flooding in Daqing oil field [He et al. 2007; Jiecheng et al. 2011; Cheng et al., 2014]. The ceramic-coating rotor significantly

helps reduce scaling effects on PCPs [H et al. 2007]. Initially, the pilot wells of RAZU ASP regarded PCPs as the method of artificial lift. However, due to operational challenges associated with using PCPs at significant depths, the design for artificial lift was subsequently revised to utilize Electric Submersible Pumps (ESPs).

Choosing alkali Type: Na_2CO_3 perform better in term of low scaling risk [Zhang et al., 2009]. In the Daqing oil field, field tests indicated that scaling caused by weak alkali is less severe than that strong alkali [Jiecheng et al. 2014; Kazempour et al. 2013; Guo et al. 2017a; 2017b; 2017 c; 2019] and average pump- check-period comparison shows better performance by Na_2CO_3 than by NaOH [Guo et al. 2019]. Hence, the RAZU ASP formulation was designed by using weak alkali type as Na_2CO_3 .

Effect of Alkali concentration in ASP formulation design: The CaCO_3 can be eliminated by operating the process at lower pH. However, silica scale deposition cannot easily treated by simply adjusting the pH, but the polymerization of silica controlled by pH. ASP flood operating below pH of 10.5 can start polymerization of silica and formation of colloidal silica [Demadis et al., 2007]. Therefore, lowering the pH does not eliminate the scale problem; it rather shifts from “magnesium silicate” to “silica scale” [Sonne et al., 2012].

Selection of scale inhibitors: The scale inhibitors either prevent scale formation or suppress the activity of already formed scales. The scale inhibitors absorb onto the crystal surface and coat the surface of already formed scale crystals, thereby reducing their growth and preventing them from adhering to the surface of pipes [Qing et al., 2002]. Therefore, in the RZU ASP pilot, the selection of scale inhibitors was carried out through silica dissolution and precipitation experiments. In the RAZU ASP formulation design, the addition of 1.5 wt% sodium carbonate results in a pH of ~11.5 at surface conditions, which results in a very high scaling tendency, primarily in connection with calcium carbonate. This result is attributed to high calcium concentrations in reservoir water and high reservoir temperature. The scale inhibitor window was constructed based on scale inhibitor studies conducted for ASP projects using sodium carbonate (Na_2CO_3) as the alkali from the literature review, as shown in Figure 1. References for most of the projects represented by the blue dots in this Figure from SPE literature as A, B, D, E, H and J are from Al Siyabi et al. (2018), Bt Alwi et al. (2016), Lo et al. (2011), Volokitin et al. (2018), Dueñas et al. (2018) and Falls et al. (1994), respectively. In this Figure, the green dotted line represents the estimated scale inhibitor deployment limits from the literature. Therefore, carbonate scaling issues for projects on the left side of this green line are manageable through scale inhibitor usage. The projects on the right side of the green dotted line shown contain operational issues associated with CaCO_3 scale deposition or have a strong indication of scaling issues. The management of these projects will be difficult based on the current available study data. In the RAZU ASP pilot, the various scenarios for mixtures of pre-flush water, formation water and ASP represented by red dots. This indicates that CaCO_3 scaling issues will be very challenging in RAZU ASP pilot to manage using currently commercially available scale inhibitors.

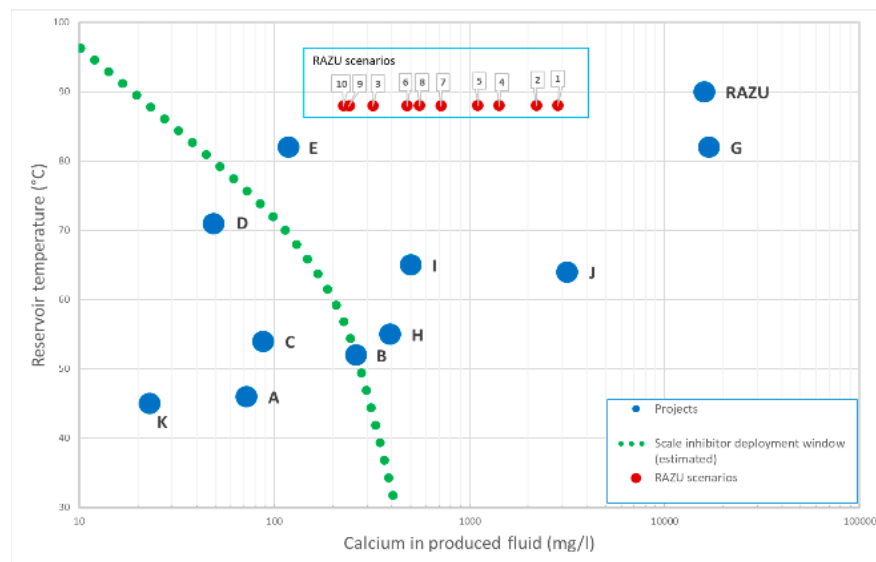


Figure 4: Estimated scale inhibitor deployment window for CaCO₃ scale based on the use of Na₂CO₃ as an alkali in ASP solutions [Murayri et al., 2019b]

3.4.3 Pre-flush operating strategies to reduce the scaling risk in ASP pilot:

3.4.3.1 Base case pre-flush design

The Pilot design incorporates an inverted 5-spot injection pattern, featuring an injection rate of 1600 bbl/day, with a central injector producing at a rate of 400 bbl/day from each of the four surrounding producers during the ASP injection phase. In scenarios involving a homogeneous reservoir, the absence of a directional aquifer, 100% operational uptime, no ion exchange between the rock and the injected water, and a Voidage Replacement Ratio (VRR) slightly exceeding one, the injection of 1-1.5 PVI softened water would effectively mitigate scaling risks through dilution. However, in the presence of an active aquifer, it is deemed necessary to implement a pre-flush of softened water at twice the PVI to displace the formation water from the pilot area. This approach is warranted due to the variability in salinity within the reservoir, which arises from the mixed sources of seawater and effluent water injected during field development. Furthermore, the elevated concentrations of divalent ions (~16,000 ppm Calcium, ~4,000 ppm Magnesium) present in the native reservoir brine exceed the tolerance levels for an ASP flood. It is also acknowledged that the producers involved in this multi-well pilot are likely to encounter scaling as a result of the interaction between alkali in the ASP slug and the divalent ions from the produced fluids. Historical injectivity data and fracture pressure analyses indicate that a softened water pre-flush at an increased rate (e.g., 3000 bbl/day) could potentially shorten the pilot duration; however, the injection rate should remain at 1600 bbl/day during the ASP slug and polymer chase drive due to the shear-thinning effect on polymer viscosity. It has been proposed that an extended pre-flush strategy, involving the injection of approximately 7 PV (pilot pattern size) of softened water into the pilot injector, could alleviate scaling concerns by effectively displacing formation water from the pilot area. A simulation of the base case, utilizing a 7 PVI soft water injection strategy, was conducted in a commercial chemical EOR simulator to assess the movement of divalent ions towards the pilot. Furthermore, reservoir realizations and uncertainty analyses were conducted, underscoring the significance of accurately capturing

aquifer strength, which was assessed at 50% high and 50% low relative to the base case, as illustrated in Table 3. Additionally, the closure of producer wells was considered to facilitate the removal of formation water from the pilot area.

The simulation outcomes indicate that after three months of initiating softened water injection, the production of divalent ions begins to decline. However, upon reopening the producers after 7PVI, the concentration of divalent ions ranges from 10% to 50% of its initial level, except in scenarios lacking aquifer support (i.e., with 50% reduced aquifer strength). Notably, cases with 50% lower aquifer strength still exhibit the potential to yield higher levels of divalent ions, approximately 1% of the total formation water, due to non-ideal vertical or areal

conformance resulting from local permeability variations. The interplay of reservoir heterogeneity and the active aquifer suggests that a moderately large pre-flush may not be adequate to mitigate scaling risks at the producers. Consequently, further optimization or alternative pre-flush operating strategies are necessary to address the scaling concerns.

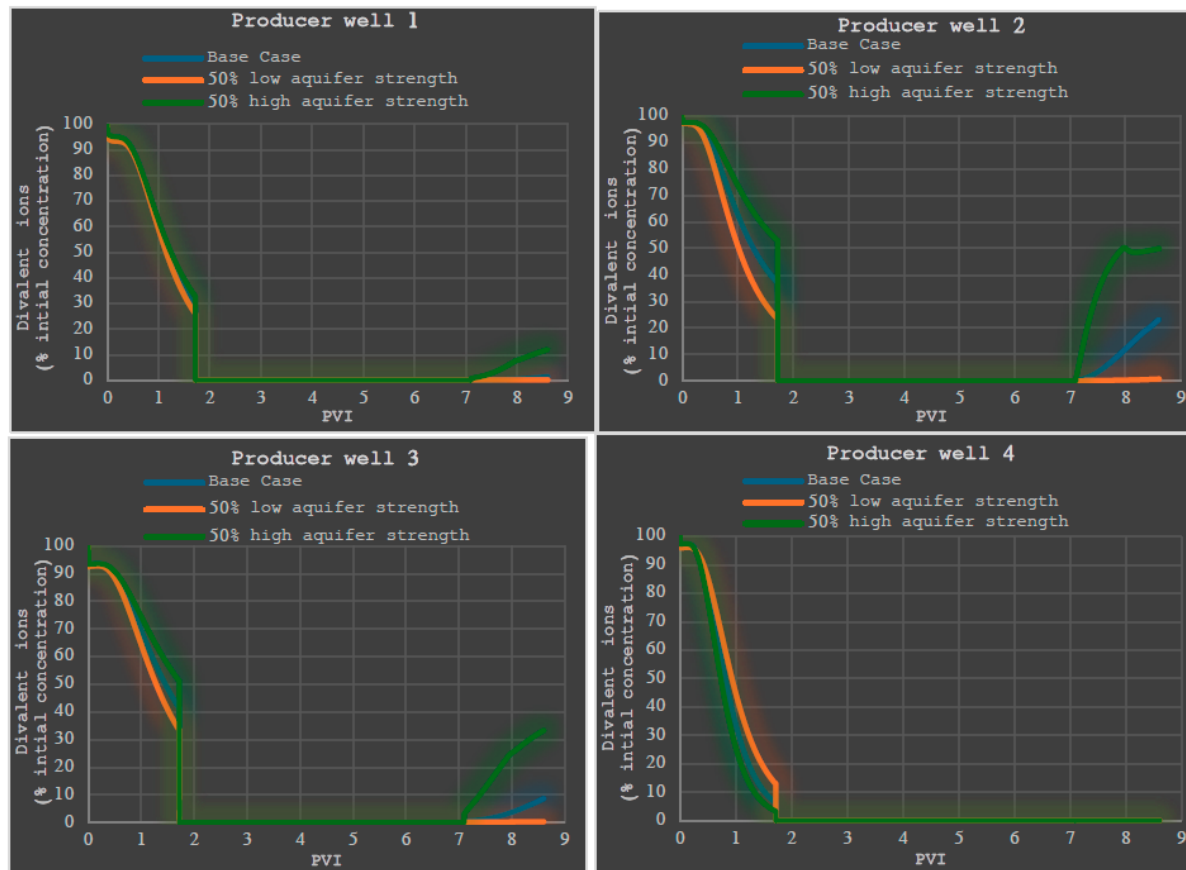


Figure 5: Divalent ions production in bases, 50% high and 50% low aquifer strength cases.

Table 3: Water influx sensitivities

Direction of Flux	Base case	50% high aquifer strength case	50% low aquifer strength case
NE	2444	3666	1833
SE	763	1144.5	572.25

3.4.3.2 Evaluation of injection pattern to reduce the scaling risk

The base-case ASP pilot design presents an elevated risk of scaling, primarily due to its utilization of an inverted 5-spot injection pattern combined with a 7PVI prolonged pre-flush technique. This configuration not only extends the pilot's duration but also escalates the expenses associated with soft water treatment. To assess the impact of divalent ions on scaling within the pilot area, the injection pattern was altered from an inverted 5-spot to a conventional 5-spot configuration (refer to Figure 6). It is important to note that each injection pattern possesses distinct advantages and disadvantages, as illustrated in Table 4. Simulation outcomes reveal that the standard injection pattern effectively reduces the generation of divalent ions. However, a residual concentration of approximately 1% remains even after substantial soft water injection. This scenario necessitates larger facilities, increased pore volumes for injection, and a significantly higher volume of chemicals, alongside the potential risk of contaminating the oil extracted from the field. Moreover, given that around three-quarters of the injected chemicals are expected to be recovered from wells situated outside the pilot pattern, persistent scaling issues linked to the 1% divalent-ion production could lead to premature termination of pilot operations, thereby hindering the achievement of the desired objectives. Consequently, the conventional 5-spot injection pattern is deemed unsuitable for this ASP pilot.

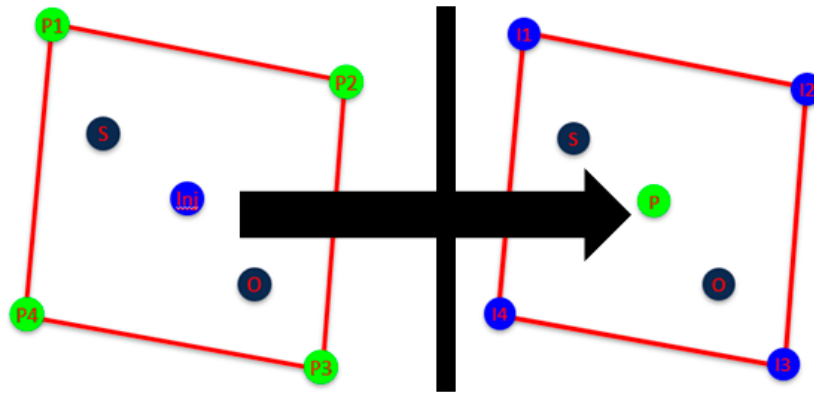


Figure 6: Representation of normal and inverted 5-spot injection pattern

Table 4: Pros and Cons for Normal versus Inverted 5-Spot injection pattern in ASP flooding Pilot

Type	Normal 5 Spot Pattern	Inverted 5 Spot Pattern
Pros	Tendency to reduce divalent ions inside the Pilot Area	One producer is on safe side in term of divalent ion production
	Less aquifer drift toward the pilot area	Lower injection rate (within facility design)
	Lower PVI required inside the pilot pattern	Lower chemical cost
Cons	Required higher PVI	3 wells in high risk in term of divalent ions production
	Pilot on risk in term of production, in case of scaling issue	One well for injection, Risk of injectivity
	High Chemical Cost	Even at 7 PVI, divalent ions production in three wells is high

3.4.3.3 Pre-flush optimization strategy to reduce the scaling risk

The recommended approach of utilizing a strategy with 7PVI softwater injection during the pre-flush phase is time-consuming, taking approximately 630 days, and incurs significant costs while producing considerable amounts of divalent ions in three wells, ranging from 10% to 22% of the initial divalent ions present in the formation water. The generation of these divalent ions poses a risk of precipitation upon reaction with alkali, leading to the formation of inorganic scale within the production wells. To mitigate these risks, pre-flush optimization was conducted using a polymer slug during the pre-flush phase. Various sensitivity analyses were performed, exploring different combinations: softwater (SW) injection alone, softwater followed by polymer injection (SW-P), polymer injection followed by softwater (P-SW), a sequence of softwater, polymer, and then softwater again (SW-P-SW), and finally, polymer followed by softwater and another polymer injection (P-SW-P). The details of each pre-flush strategy are outlined in Table 5. The simulation results indicate that the SW-P-SW strategy effectively reduces divalent ions by up to 2% of the initial concentration in the formation water. Therefore, it is optimal condition represented by the simulation case involving 1PVI of softwater, followed by 0.75 PVI of polymer slug, and concluding with 1PVI of softwater, which minimizes the polymer usage, shortens the pilot duration, and decreases divalent ion levels, as illustrated in Table 5. It is observed that certain simulation cases yield less than a 2% production of divalent ions; however, these scenarios necessitate higher PVI values for either polymer or softwater, consequently extending the pilot duration. Further optimization of the pre-flush process was conducted by varying the polymer concentration and viscosity to assess their effects on divalent ion production. Several simulation cases were executed, as detailed in Table 6. The results reveal that increasing viscosity from 3 to 4 cp enhances sweep efficiency, while further increases from 4 to 10 cp provide minimal additional benefits. Simulation case-6 demonstrates optimal oil recovery, reducing divalent ion levels from 10% to less than 1% in producer-1, from 22% to 4.5% in producer-2, and from 22% to less than 1% in producer-3, compared to the base case, as depicted in Plot (1) of Figures 7. This optimized scenario is projected to save 370 days in pilot duration and reduce operating costs, attributed to the 4.15 PVI, which injects less fluid and enhances oil recovery and oil desaturation when compared to the base case, as illustrated in Plot (2) of Figure 7. When evaluating the chemical oil ratio, defined as the cumulative oil produced divided by the cumulative water injected, the final optimized cases demonstrate superior chemical effectiveness relative to the base case, as depicted in plot (3) of Figure 7. Consequently, the implementation of a polymer

slug in the pre-flush strategy will minimize the risk of scale formation, reduce cooling effect in the pilot, shorten the duration of the pilot (thereby lowering costs), and enhance both oil recovery and the oil-to-chemical ratio.

Table 5: Pre-flush optimization simulation cases descriptions

Pre-flush type	Name	Pre-flush design	Pre-flush PVI and Time				Max. production (% initial)	
			Polymer viscosity (cp)	PVI (P)	PVI (SW)	Total PVI		Time (days)
SW	Base case	7PVI (SW) with Shutin pilot producers	2	0.00	7.00	7.00	630	22.0
	PF1 Case	7PVI (SW) with No Shutin pilot producers	2	0.00	7.00	7.00	630	42.0
SW-P	PF2 Case	1PVI (SW)+ 1PVI (P)	2	1.00	1.00	2.00	259	13.6
	PF3 Case	2PVI (SW)+ 1PVI (P)	2	1.00	2.00	3.00	349	8.0
	PF4 Case	3PVI (SW)+ 1PVI (P)	2	1.00	3.00	4.00	439	6.0
	PF5 Case	4PVI (SW)+ 1PVI (P)	2	1.00	4.00	5.00	529	5.0
P-SW	PF6 Case	1PVI (P)+ 1PVI (SW)	2	1.00	1.00	2.00	259	17.0
	PF7 Case	2PVI (P)+ 1PVI (SW)	2	2.00	1.00	3.00	428	1.0
SW-P-SW	PF8 Case	1PVI (SW)+ 1PVI (P) +1PVI (SW)	2	1.00	2.00	3.00	349	2.4
	Optimized Pre-flush Case	1PVI (SW)+ 0.75PVI (P) +1PVI (SW)	2	0.75	2.00	2.75	307	2.0
	PF9 Case	1PVI (SW)+ 0.5PVI (P) +1PVI (SW)	2	0.50	2.00	2.50	265	5.8
	PF10 Case	1PVI (SW)+ 1PVI (P) +2PVI (SW)	2	1.00	4.00	5.00	529	3.5
	PF11 Case	1PVI (SW)+ 0.5PVI (P) +3PVI (SW)	2	0.50	4.00	4.50	445	3.0
P-SW-P	PF12 Case	1PVI (P)+ 1PVI (SW) +1PVI (P)	2	2.00	1.00	3.00	428	2.0
	PF13 Case	1PVI (P)+ 2PVI (SW) +1PVI (P)	2	2.00	2.00	4.00	518	4.2

Table 6: Pre-flush optimization simulation cases descriptions

Simulation Cases	Polymer Concentration (ppm)	Polymer Viscosity (cp)		PVI						Aprox. total polymer required in bbl
		In pre-flush and ASP slug	In polymer chase drive	Pre-flush		ASP Slug	Polymer Chase	Water		
				SW	P					
Case1	1500	3	3	1	0.75	1	0.3	1.05	2	729
Case2	2000	4	4	1	0.75	1	0.3	0.60	2	
Case3	3000	7	7	1	0.50	1	0.3	0.40	2	
Case4	3500	10	10	1	0.40	1	0.3	0.37	2	
Case5	3500	10	10	1	0.75	1	0.3	1.05	2	
Optimized Pre-flush Case	1500	3	3	1	0.75	1	0.3	0.50	2	510 (however, reduces oil recovery)
Case6: Final optimized	2000	3	4	1	0.75	1	0.3	0.79	2	729
Case7	3000	3	7	1	0.75	1	0.3	0.53	2	
Case8	3500	3	10	1	0.75	1	0.3	0.45	2	

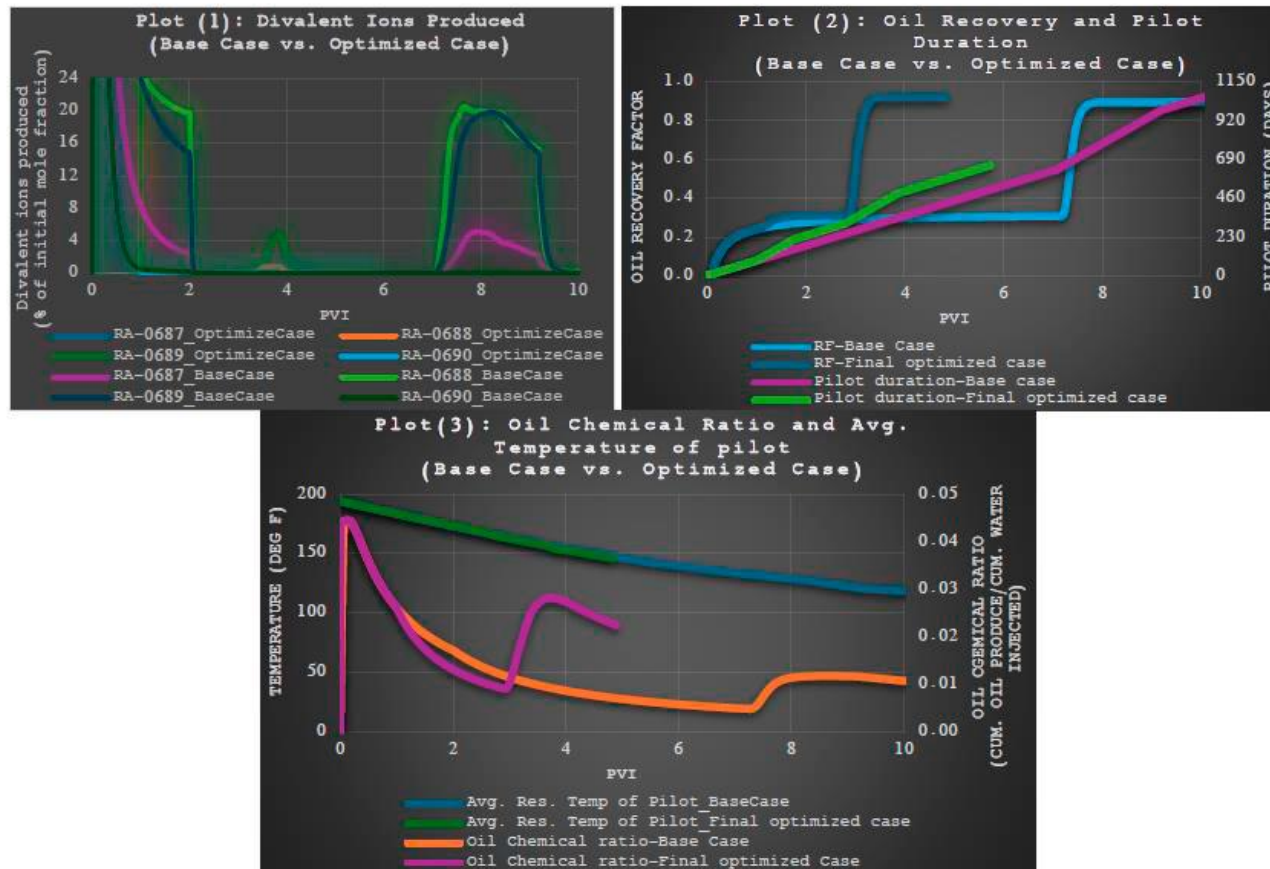


Figure 7: Comparison of optimized strategy case with reference base case

3.4.4 Re-optimization of the ASP formulation for lower temperature range

The implementation of an extended pre-flush injection leads to a notable cooling effect within the reservoir due to the injected fluid. Thermal simulations were conducted using a commercial thermal simulator to assess the temperature variation within the pilot area resulting from the extended pre-flush injection. This cooling effect is primarily linked to the injection of multiple volumes of softened water under surface conditions. The simulation results indicate a temperature decrease from 90°C to a range of 50-70°C, as illustrated in Figure 8 due to multiple PVI in pre-flush phase. This cooling phenomenon significantly influences the design of the Alkali-Surfactant-Polymer (ASP) formulation. Furthermore, the base case exhibits a more pronounced cooling compared to the optimized case presented in Figure 8.

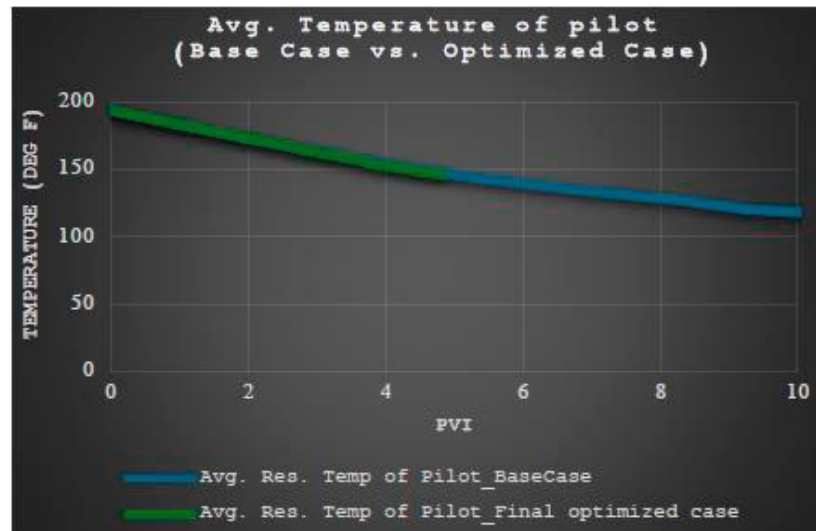


Figure 8: Average pilot pattern reservoir temperature as a function of softened water PVI

In light of the cooling effect, the initial design of the ASP formulation developed in the laboratory, as well as its successful testing in SWCTT, is further examined at reduced temperatures from the laboratory. The results from the core flood indicate a notable decrease in oil recovery when the temperature is lowered from 90°C (core flood KOC#35) to 50°C (core flood KOC#39), as illustrated in Figure 9. A detailed description of the core flood is depicted in Table 7. Consequently, a re-evaluation of the chemical formulation at lower temperatures was undertaken. To ascertain whether the decline in oil recovery was attributable to a change in optimal salinity, phase behavior tubes were prepared for the ASP formulation at 50°C. It was observed that the optimal salinity shifted to the range of 4-5 wt% NaCl. To determine if operating under sub-optimal conditions would lead to a significant decrease in oil recovery, a core flood (KOC#38) was performed at 2 wt% NaCl salinity and 90°C. During this coreflood (KOC#38), the oil recovery and oil cut resulting from the chemical injection were notably reduced similar to optimum salinity coreflood (KOC#39) at 50°C. Although the surfactant concentration for KOC#35 was lower than that for KOC#38 and KOC#39, a higher surfactant concentration would be more advantageous for oil production. The co-solvent concentration for KOC#35 exceeded that of KOC#38 and KOC#39; however, it is expected that the co-solvent concentration would not significantly affect oil recovery, provided it is sufficient to prevent surfactant phase separation. As shown in Table 6, the remaining oil saturation after the chemical core flood in KOC#35 is 0.01, which is lower than 0.29 in KOC#39 (low-temperature flood) and 0.25 in KOC#38 (under-optimal flood). Therefore, core floods KOC#38 and KOC#39 are identified as under-performing in all metrics, necessitating further efforts to optimize the formulation for improved recoveries at the anticipated lower temperatures.

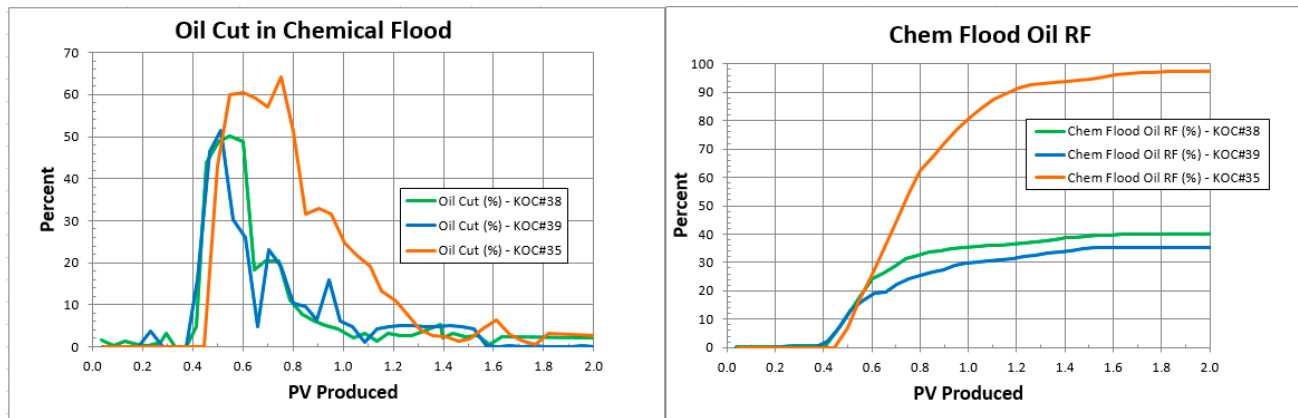


Figure 9: Oil cut and oil recovery for low temperature (KOC#39), high temperature (KOC#35: optimal salinity; KOC#38: under-optimal salinity) [Al-Murayri et al., 2019b].

Table 7: Core floods (KOC#35, 38 and 39) description

Flood Name	Porous med. & #	Size	PV, cc	Perm., Darcy	Surfactant	Nacl, %	Na2CO3, %	Polymer ATBS (ppm)	Co-solvent, LEA %	Chemical slug size, PV	Soi	Water flood Recovery (%)	Sorw (oil sat. after water flood)	Chemical Flood Recovery (% of Sorw)		Sor* (oil sat. after CF)	Mobilized HC by Chemical (Sorw - Sor*)
														1 PV	2 PV		
KOC#35	BT#27	1.5"×12"	79.4	3.0	0.42% IOS 24-28 0.28% IOS 15-18	3.0	1.5	1500	1.5	0.3	0.77	54.5	0.35	77.1	97.5	0.01	0.34
KOC#38	BT#29	1.5"×12"	83.9	1.9	0.6% IOS 24-28 0.4% IOS 15-18	2.0	1.5	1500	1.2	0.3	0.77	44.8	0.43	35.4	40	0.25	0.17
KOC#39	BT#30	1.5"×12"	80.9	2.9	0.6% IOS 24-28 0.4% IOS 15-18	3.0	1.5	1500	1.0	0.3	0.79	43.7	0.45	29.7	35.4	0.29	0.16

It is established that a decrease in temperature enhances the tendency of IOS surfactants to favor the aqueous phase. It is hypothesized that a similar mechanism, characterized by the formulation operating below its optimal conditions, is applicable to floods KOC#38 and KOC#39. To achieve a reduction in the optimal salinity of the ASP formulation from 4-5 wt% NaCl to approximately 3 wt% NaCl, two series of phase behavior tubes were developed. One method to adjust the optimal salinity of the ASP formulation involves lowering the value by increasing the relative proportion of the higher carbon number surfactant, which is more hydrophobic, within the surfactant blend. The SWCTT ASP formulation at 90°C exhibited a 60:40 ratio of O352 to O332, as detailed in Table 6. The two new series of phase behavior were created by modifying the surfactant ratio to 70:30 (0.6 wt% O352 and 0.26 wt% O332) and 80:20 (0.6 wt% O352 and 0.15 wt% O332) at a reduced temperature of 50°C. The 70:30 and 80:20 formulations demonstrated optimal salinity levels of 4 wt% NaCl and 2.5 - 2.75 wt% NaCl, respectively. However, the coreflood experiment for the 70:30 formulation indicated a lower incremental oil recovery during the ASP flood.

Subsequently, the 80:20 formulation was tested at a lower temperature on a dead oil core flood using Bentheimer core (KOC#41), with the chemical concentrations outlined in Table 8. The performance of the 80:20 O352:O332 blend, comprising a total of 0.75 wt% surfactant and 2.5 wt% L4-2 at 50°C, was comparable to that of the 60:40 O352:O332 blend, which contained a total of 0.7 wt% surfactant and 1.5 wt% L4-2 at the same temperature. It is important to note that the concentration of the co-solvent (L4-2) cannot be further reduced at lower temperatures, despite the necessity for a higher co-solvent concentration to enhance the solvency of the surfactant in the ASP solution at 50°C. For instance, surfactant phase separation continues to occur when the L4-2 concentration. The pilot area experiences a temperature range of 60-75°C. Additionally, the robustness of the 80:20 case was evaluated at a temperature of 70°C during the core flood (KOC#42), maintaining the same surfactant blend ratio while decreasing the co-solvent concentration from 2.5 wt% to 2 wt% L4-2. It is noted that higher temperatures necessitate a lower co-solvent concentration to maintain the surfactant in solution. The results of this core flood demonstrated remarkable efficacy, achieving oil recovery rates of 85.7% and 91.1% of the remaining oil after waterflooding at 1 PV and 2 PV, respectively, as illustrated in Figure 10.

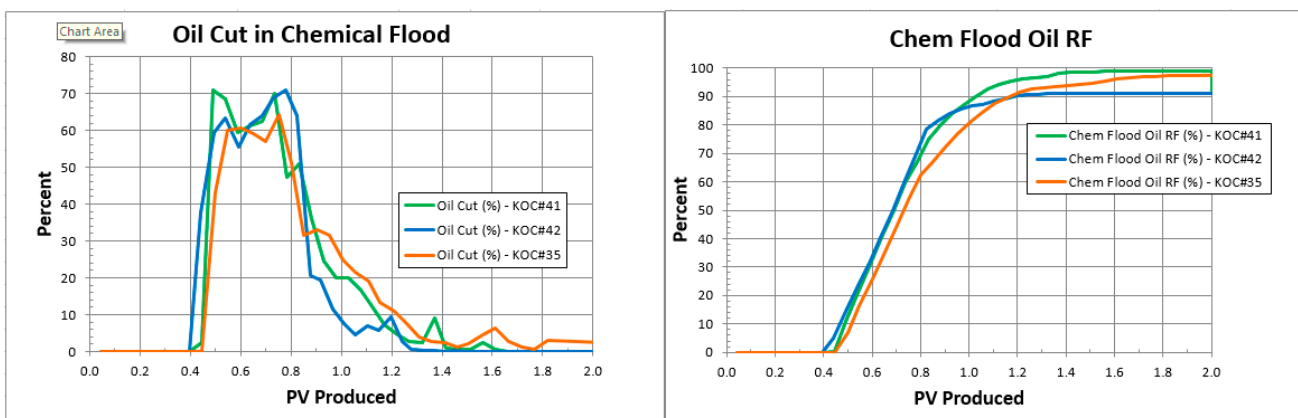


Figure 10: Comparison of floods at 50°C (KOC#41), 70°C (KOC#42) and 90°C (KOC#35)

Table 8: Core floods (KOC#35, 41 and 42) description

Flood Name	Porous med. & #	Size	PV, cc	Perm., Darcy	Surfactant	Nacl, %	Na2CO3, %	Polymer ATBS (ppm)	Co-solvent, LEA %	Chemical slug size, PV	Soi	Water flood Recovery (%)	Sorw (oil sat. after water flood)	Chemical Flood Recovery (% of Sorw)		Sor* (oil sat. after CF)	Mobilized HC by Chemical (Sorw - Sor*)
														1 PV	2 PV		
KOC#35	BT#27	1.5"x12"	79.4	3.0	0.42% IOS 24-28 0.28% IOS 15-18	3.0	1.5	1500	1.5	0.3	0.77	54.5	0.35	77.1	97.5	0.01	0.34
KOC#41	BT#31	1.5"x12"	82.3	1.6	0.6% IOS 24-28 0.15% IOS 15-18	2.75	1.5	1500	2.5	0.3	0.77	56.7	0.33	87.0	99.0	0.00	0.33
KOC#42	BT#32	1.5"x12"	82.1	1.7	0.56% IOS 24-28 0.14% IOS 15-18	2.75	1.5	1500	2.0	0.3	0.76	53.7	0.35	85.7	91.1	0.03	0.32

4. Conclusions

This paper describes a novel over-flush strategy in pre-flush phase to alleviate carbonate-scaling concerns in connection with ASP injection. The conventional approach of pre-flushing (small PV at VRR=1) is expected to preclude the implementation of ASP flooding due to carbonate scaling at the producers. The extended pre-flush (over-flush) softwater injection strategy does not reduce the scaling concern due to active aquifer near pilot area, which pushes formation water into pilot area. In the view of this scaling inhibitor design, PCPs pump selection and 20% ATBS type polymer selection considered in the ASP pilot deployment. However, these selection strategies have limit to reduce scaling concern. Therefore, pilot operating strategy and pre-flush design shows major impact on scaling concern.

The simulation results show pre-flush phase optimization diminishes the scaling risk by using high viscous polymer slug injection (~0.6 to 0.75PVI) and small over-flush injection (~1.5PVI) strategy while maintaining VRR>1.5 in the pilot area. The smartly designed pre-flush injection phase (first inject 1PVI soft water than 0.75 PVI polymer (same viscosity as ASP slug) than 1PVI soft water injection) diminishes the significant scaling concern with other benefits over originally designed base over-flush method such as:

- Reduction of significant divalent ions production from 1580ppm Ca⁺⁺ & 353ppm Mg⁺⁺ (in producer 1) and 3476ppm Ca⁺⁺ & 776ppm Mg⁺⁺ (in producer 2 and 3) to 158ppm Ca⁺⁺ & 35ppm Mg⁺⁺ (in producer 1 and 3) and 663ppm Ca⁺⁺ & 148ppm Mg⁺⁺ (in producer 2), respectively
- Saving 370 days pilot duration time as well as operating cost due to 4.15 PVI injection less;
- Provides better pilot oil recovery and oil desaturation;
- Provides high chemical oil ratio (i.e. utilization of chemical for extra bbl. of cumulative oil produced) and
- Reduces the risk of significant cooling in the pilot area, which will help in the effectiveness of chemical formulation for pilot.
- 20% ATBS type polymer reduces the risk of polymer viscosity and precipitation due to hydrolysis at elevated temperature.
- To work ASP formulation at lower temperature, the re-tuning of ASP formulation is required i.e. shifted optimal salinity from 3 to 2.75 wt%, co-solvent from 1.5 to 2 wt% and changing proportion of IOS surfactant blend for this chemical formulation to work at lower temperature range from 70degC to 50degC.

Declaration of competing interest

Authors declare no competing financial interests or personal relationships with other people or organizations that could inappropriately influence (bias) our work

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