Journal of Multidisciplinary Engineering Science Studies (JMESS)
ISSN: 2458-925X
Vol. 4 Issue 12, December - 2018

The Employment Of CMG-STARS To Simulate Alkaline/Ionic Liquid/Polymer (AILP) Flooding Results

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***Abstract*—One of the most successful enhanced oil recovery techniques, nowadays, is chemical (Alkaline/Surfactant/Polymer) flooding and modeling the experimental results of these experiments is one of the most difficult challenges. For that, this study has been conducted to obtain the history matching of the laboratory scale results employing STARS. Some of the chemical flooding experiments have been done to get additional RF. We noticed that the most challenging factors throughout building up the models were the pure polymer viscosity and oil-water relative permeability curves. Also, a fair range of assumptions was made to address the unavailability of any information and adjust the particular values to end up with a successful match of cumulatively produced oil, water cut, oil cut, and pressure drop curves. Finally, understanding how to model the chemical flooding performance in laboratory scale will develop the possibility of simulating chemical floods in industrial scale.**

***Keywords*—CMG-STARS; AILP flooding; history matching; sensitivity study; oil viscosity; slug injection time.**

I. INTRODUCTION

Growing the demand for Oil production has demanded the oil industry to provide oil from more challenging areas, where the oil is less accessible, using advanced recovery techniques. After primary and secondary flooding modes, two-thirds of the original oil in place (OOIP) is not recovered that demands EOR methods to be produced. EOR processes can be categorized as thermal oil recovery, miscible flooding, and chemical flooding.[1] We can classify the chemical flooding methods as a crucial method for EOR to recover residual oil that cannot be achieved by the conventional flooding. One of the recently applied chemicals on the laboratory scale is known as Ionic Liquid (IL). The new compounds cannot be employed in the field before examining their performances. Laboratory scale will not consolidate all of the reservoir conditions. For that, using a simulator to model the field conditions based on the laboratory results is needed.

Computer Modeling Group LTD. (CMG) developed a three-phase multi-component thermal and steam additive simulator, which is known as STARS.[2] It is admitted for its capability to model both laboratory and field-scale types while also having the potential to handle complex chemical performance. STARS is a numerical reservoir simulator that models various kinds of flooding such as water, chemical, thermal and non-thermal flooding methods. It also generates a different dimension and structure models. Steam flooding, chemical flooding, ..., etc., applying a comprehensive range of grid and porosity criteria in both field and laboratory scale. Up to now, few types of research have been conducted using STARS (CMG) software.[3,4] Many works based on the modeling of chemical flooding implementing different simulation methods have been declared since the 1970s. Pope and Nelson (1978) reported a chemical flood simulator (one-dimensional and compositional) to determine the additional oil recovery as a function of many variables.[5] Paul et al. (1982) used a simple model for prediction of micellar/Polymer flooding.[6] Bhuyan et al. (1990) showed a generalized model for high pH chemical floods.[7] Vaskas (1996) declared an economic model for evaluation for chemical flooding.[8] Han et al. (2007) announced a compositional chemical flooding simulator for surfactant–Polymer flooding.[9] Najafabadi (2009) developed a simulator for surfactant phase behavior, which is very much crucial in surfactant flooding.[10] Recently, STARS was successfully manipulated to history match the laboratory results of Alkaline + Ionic Liquid flooding.[11]

In this study, STARS (CMG) software is implemented to build a history match for non-thermal chemical flooding experiments. The history match managed by waterflooding and chemical flooding (Alkali/Ionic Liquid/Polymer). The accumulative oil recovery, oil cut, water cut, production rated and differential pressure were chosen for history matching. After achieving a successful history match, various conditions that could not be investigated in the laboratory were applied to predict their effect on the RF.

II. MODELING SECTION

A. *Materials and Methods*

A Cartesian rectangular coordinate grid type was applied to create the sand pack experiments. Ninety blocks in the flow direction were assigned to increase the simulation accuracy. The number of blocks in the other two directions was set equal to one to simulate 1-D flow. The porosity, absolute permeability, initial water, and oil saturation values are constant. The details of sand pack samples, model and fluid properties employed in the simulation are addressed in Table 1.

History match is the used technique to simulate and estimate the performance of chemical flooding. One of the principal goals of this study is the history matching of the specific experiments and predicting the results of applying conditions that couldn't be implemented in the laboratory. Thereby, the simulation and history matching are used in some chemical flood experiments that were accomplished by **Tunnish (2017)**.[12]

Table 1. Rock and fluid properties.

Rock Properties		Fluid Properties	
Grid Size (x), cm d, cm L, cm	0.082 3.3 7.4	ρ_w, g/cm^3 μ_w, cP	1.004813 1.07
Grid	90	ρ_o, g/cm^3 μ_o, cP	0.97 1,200
Kx, Ky, Kz, mD	3800	ρ_{Alkali}, g/cm^3	1.01
$\emptyset =$	0.38	$\rho_{Polymer}$, g/cm^3	1
P, psi	14.7	ρ_{IL}, g/cm^3 μ_{IL}, cP	1.101297 136.6
T, °C	22.5	Soi Swi	0.9 0.1
Rock Type	Sandstone		

III. RESULTS AND DISCUSSION

A. *Simulation of Experimental Results*

In this study, the compositions of the chemical slugs of the experiments planned to be simulated were 0.1 % wt. PHPA (Polymer flooding), 0.7 % wt. Na_2CO_3 + 0.1 % wt. PHPA (Alkaline + Polymer flooding), 1,000 ppm [EMIM][Ac] + 0.1 % wt. PHPA (Ionic Liquid + Polymer flooding) and 0.7 % wt. Na_2CO_3 + 1,000 ppm [EMIM][Ac] + 0.1 % wt. PHPA (Alkaline + Ionic Liquid + Polymer flooding).

The core samples were modeled as a Cartesian grid with ninety blocks, as presented in Fig. 1. Concerning the position of the wells, the injector and producer were placed in first and ninety blocks, respectively. As described in details in Tunnish's dissertation, experimentally, about 6.6 PVs of pure SPB were injected to reach about 99.5 % water cut. After that, chemical slugs were introduced with suitable constraint requirement under the well-section. These chemical slugs supported by about 2 PVs of brine,[12] as detailed in Table 2. During these runs, the injection rate was 0.75 cm^3/min, the temperature was 21.5 ± 1 °C, and the pressure was 14.7 psi.

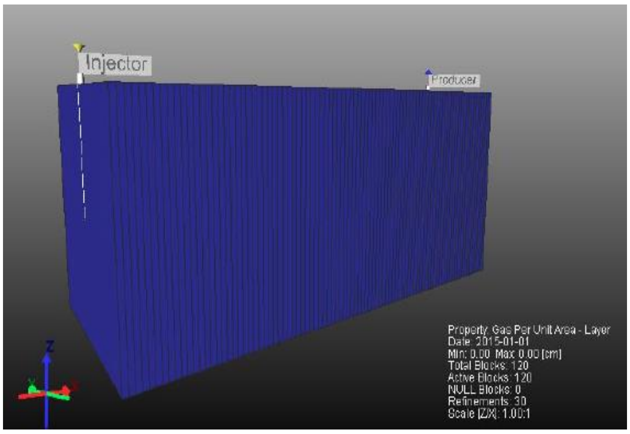

Fig. 1. Cartesian grid design for chemical flooding.

Table 2. The procedure of the experimental results.

Experiment	Step 1	Step 2	Step 3
Polymer Flooding	6.6 PV SPB	1 PV of Polymer	2 PV (SPB)
Alkaline + Polymer Flooding	6.6 PV SPB	1 PV of Alkali + Polymer	2 PV (SPB)
Ionic Liquid + Polymer Flooding	6.6 PV SPB	1 PV of Ionic Liquid + Polymer	2 PV (SPB)
Alkaline + Ionic Liquid + Polymer Flooding	6.6 PV SPB	1 PV Alkali + Ionic Liquid + Polymer	2 PV (SPB)

B. *Prediction of Chemical Flooding Performance Under Different Conditions*

In this section, a Polymer-flooding experiment was chosen for data prediction. The influences of varying the properties of the displacing phase and relative permeability curves were conducted. Fig. 2 reports the cumulative oil production curve of the simulator when the particular experimental relative permeability curves manipulated. It is obvious that neither the waterflooding curve nor the chemical slug RF curve is approaching the experimental cumulative oil recovery profile. So, some properties should be tuned to propose the most appropriate match. The first parameter has been adjusted is the pure Polymer viscosity. Changing the viscosity of pure Polymer sample, keeping the same concentration of chemicals in the slug, the same slug size and the same relative permeability curves as concluded from the experimental data was the first trial. A range of viscosities was considered starting from the viscosity of 0.1 % wt. PHPA + SPB (4.74 cP) mixture and ending with 1,000 cP. As can be depicted from Fig. 3, the pure Polymer viscosity is affecting the additional oil recovery, which means that tuning only the Polymer viscosity will not be enough to achieve a good match. The next step was modifying the water and oil relative permeability curves. Fig. 4 (a & b) and Fig. 5 (a & b) exhibit the influence of changing krw and kro, respectively, on the oil production profile. It is notable that the krw concerns the early time of the oil production profile; however, the kro values control the late time of the recovery process. So both oil and water relative permeabilities are essential for history matching. As a conclusion, we need to work on both pure Polymer viscosity and the relative permeability curves together to perform proper history matching. Fig. 6 represents a successful history matching, after tuning both Polymer viscosity (275 cP) and relative permeability curves. The history match of the water cut, oil cut, and pressure drop curves, as shown in Fig. 7, is good except at the point that the Polymer slug was introduced at, especially for the pressure drop curve.

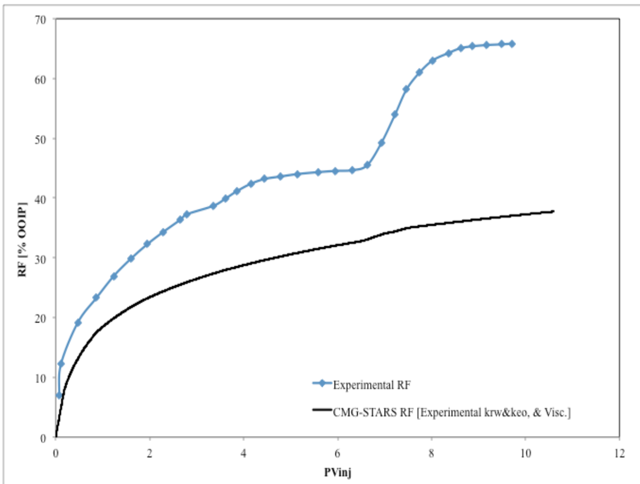

Fig. 2. Effect of applying the same experimental Polymer + SPB mixture viscosity and water-oil relative permeability curves on cumulative RF.

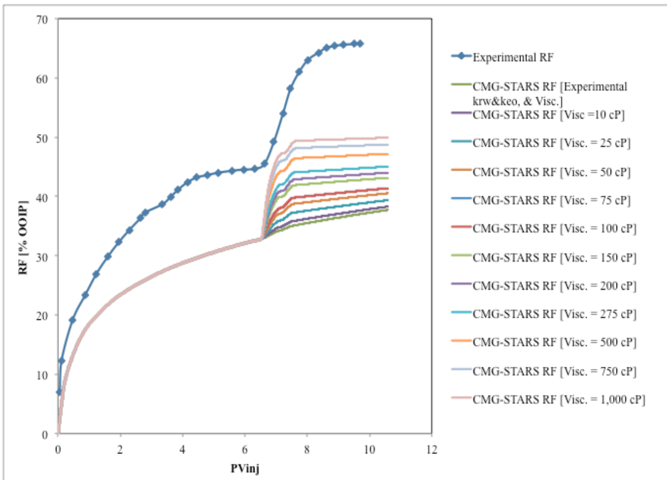

Fig. 3. Effect of changing pure Polymer viscosity on cumulative RF.

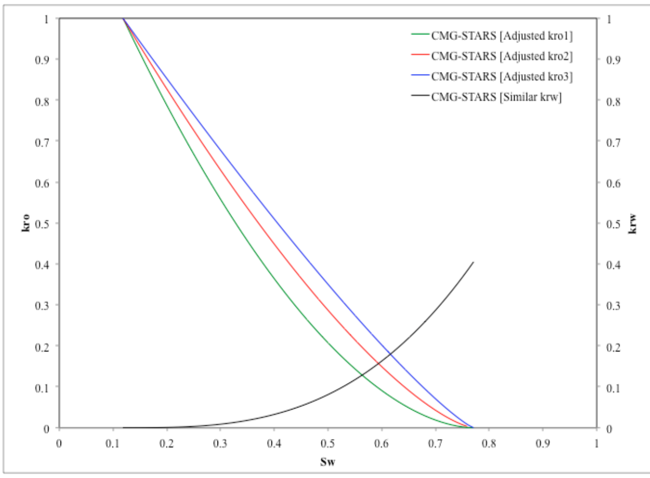

Fig. 4a. kro curve variation.

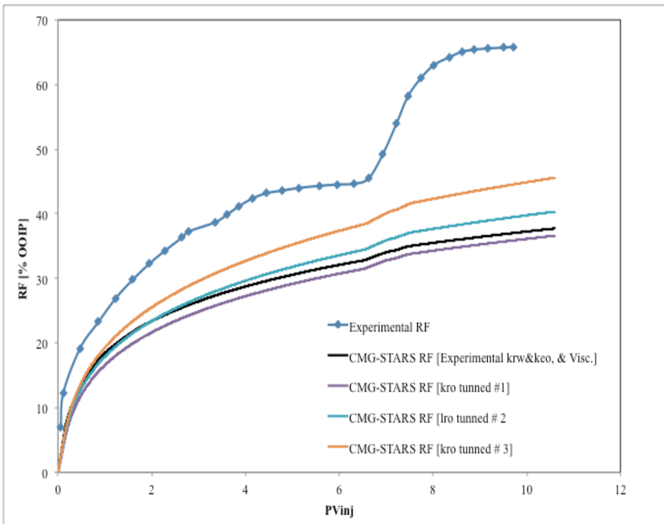

Fig. 4b. Effect of adjusting oil relative permeability curve on cumulative RF.

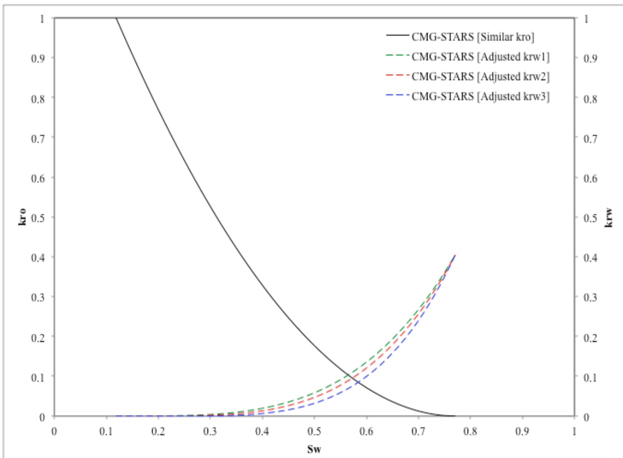

Fig. 5a. krw curve variation.

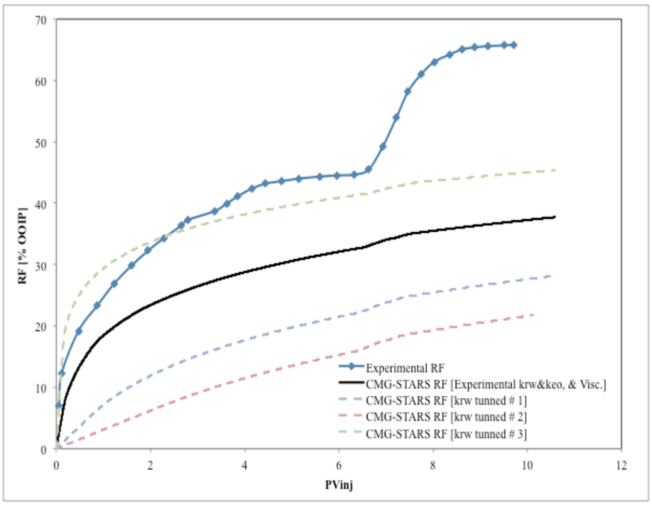

Fig. 5b. Effect of altering water relative permeability curve on cumulative RF.

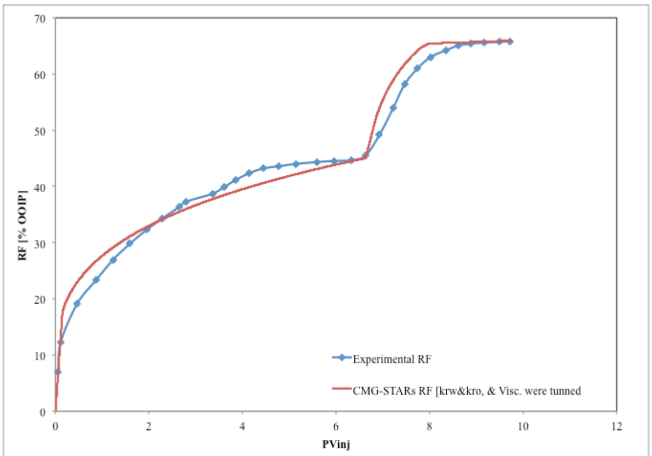

Fig. 6. Effect of tuning both pure Polymer viscosity and relative permeability curves on cumulative RF.

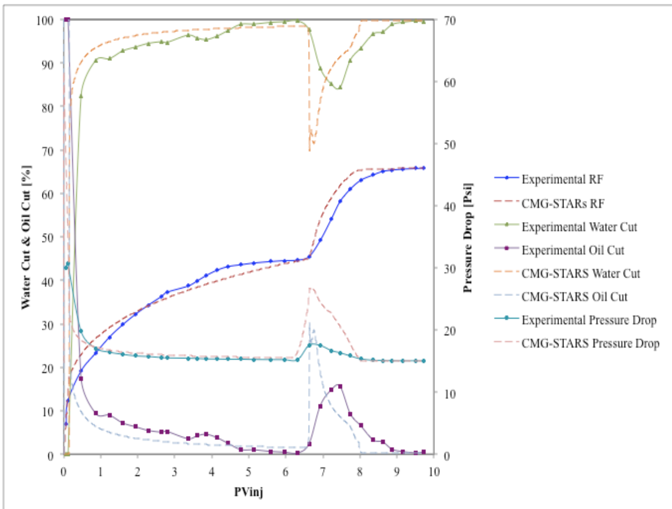

Fig. 7. History matching of experimental and simulation cumulative oil recovery, water cut, oil cut, and pressure drop curves for 1PV (Polymer) slugs.

C. Simulation of Chemical Flooding Experimental Results

Six components (water, oil, Alkali, Ionic Liquid, Polymer, and salt "Na, Cl, Mg2, and Ca2") were arranged to simulate the chemical flooding techniques. Two phases present in the simulation are aqueous and oleic phases. During history matching, relative permeability and pure Polymer viscosity were the changing parameters tuned to match the sand pack flood results. The adsorption potential of rock to the chemicals was identified from the data provided in the software templates.

The history-matched model was used for various flood processes. Many experimental runs with different chemical slugs compositions were matched. Three runs formed with, 1 PV of an Alkali + Polymer, 1 PV of Ionic Liquid + Polymer, and 1 PV of Alkali + Ionic Liquid + Polymer were simulated and history matched. The experimental and STARS results of these flooding runs are displayed in the Figs. 8, 9, and 10, respectively. The history matching of these runs was performed by applying the same properties that resulted in successful history matching for Polymer flooding in the previous section. The upside is that the simulator provided almost the same final RF of the experimental results, as detailed in Table 3. However, the history matching curves at the chemical slug injection time were not proper, due to mostly the high viscosity of Polymer assumed in the entry data of the simulator to reach to the same performance of the Polymer that observed in the laboratory results.

Table 3. Additional and final RF results of experimental and simulator chemical flooding.

Composition)of) the)Slug)	Waterflooding)RF)[%OOIP])		Total)RF)[%)OOIP])		Additional)RF)[%)OOIP])	
	Experimental)	Simulator)	Experimental)	Simulator)	Experimental)	Simulator)
SPB)–)Alkali)+) Polymer)–)SPB)	45.22)	45.42)	68.15)	68.07)	22.93)	22.65)
SPB)–)IL)+) Polymer)–)SPB)	45.14)	45.67)	68.86)	68.93)	23.72)	23.26)
SPB)–)Alkali)+)IL) +)Polymer)–)SPB)	45.73)	46.16)	73.00)	72.87)	27.27)	26.71)

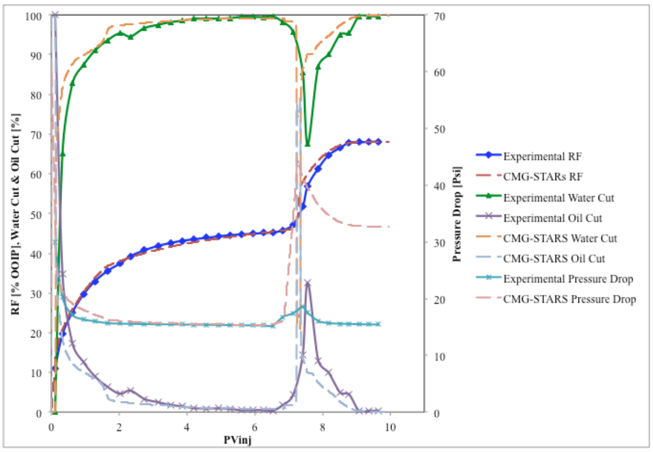

Fig. 8. History matching of experimental and simulation cumulative oil recovery, water cut, oil cut, and pressure drop curves for 1PV (Alkaline + Polymer) slug.

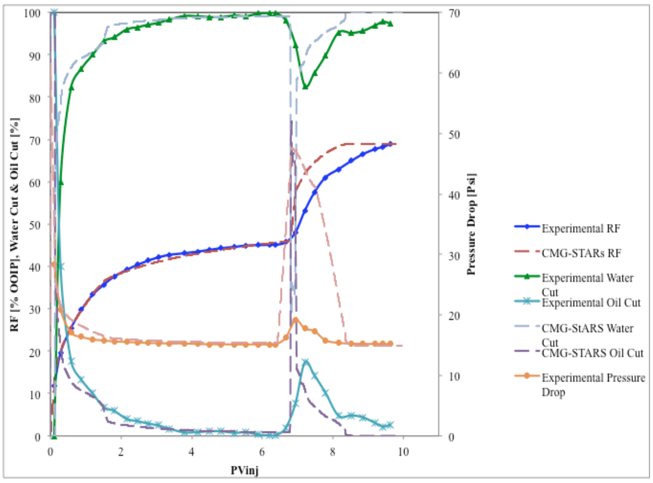

Fig. 9. History matching of experimental and simulation cumulative oil recovery, water cut, oil cut, and pressure drop curves for 1PV (IL + Polymer) slug.

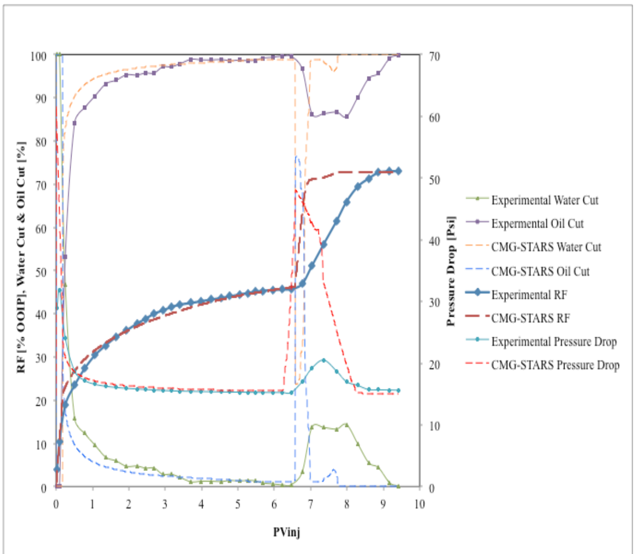

Fig. 10. History matching of experimental and simulation cumulative oil recovery, water cut, oil cut, and pressure drop curves for 1 PV (Alkali + IL + Polymer) slugs.

CMG-STARS simulator gave an incredible history match of the laboratory results on cumulative oil recovery profile. However, the match during the time of injecting chemical slug was not good regarding water cut, oil cut, and pressure drop curves for Polymer flooding, Alkaline + Polymer flooding, IL + Polymer flooding, and Alkaline + IL + Polymer flooding.

IV. 4. SENSITIVITY STUDY

The sensitivity of changing the concentration of chemicals in the slug, temperature, oil viscosity, viscosity of the displacing phase, and slug injection time on the RF will be studied. The predicted results will help us to estimate the performance of various flooding conditions.

A. Effect of Chemical Concentration on the RF

The performance of chemical concentrations for different techniques was examined. For a slug of Polymer flood, as can be seen in Fig. 11, 0.0001 to 0.5 % wt. Polymer ratios were assumed. According to the results, the additional RF grows noticeably as the proportion of Polymer in the injected slug increases from 0.0001 to 0.35 % wt. No improvement in the RF profile was witnessed when the Polymer ratio passed more than 0.35 % wt.

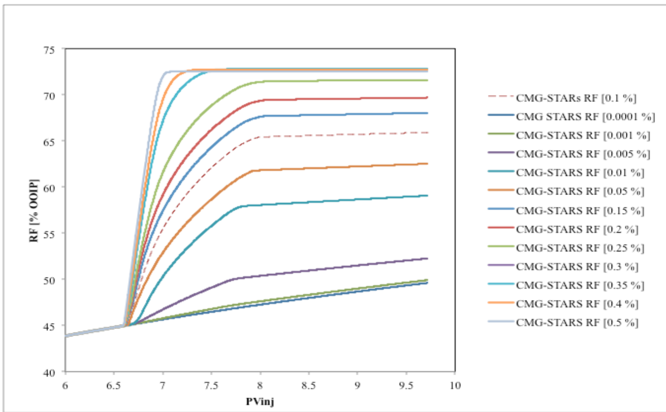

Fig. 11. Effect of Polymer concentration on the Polymer efficiency.

B. Effect of the Temperature on the RF

The range of temperature from 15 ^{o}C to 70 ^{o}C was studied, to investigate the effectiveness of Polymer slug on the RF of heavy oil under different temperatures. Fig. 12 exhibits the cumulative production of the oil under several temperatures; it is obvious that the temperature controls directly the oil viscosity, which significantly decreases as the given range of temperature rises. The reduction in oil viscosity improves the sweep efficiency and RF, as the impact of temperature on decreasing the Polymer

+ SPB viscosity is much smaller than that in oil case. It is noted that RF of brine flooding grows considerably as the assumed temperature rises. For the Polymer slug injection, the additional RF develops significantly as the temperature increases from 15 °C – 30 °C. However, the development in the additional RF was small (about 0.1 % OOIP), as the temperature raised from 30 °C to 70 °C.

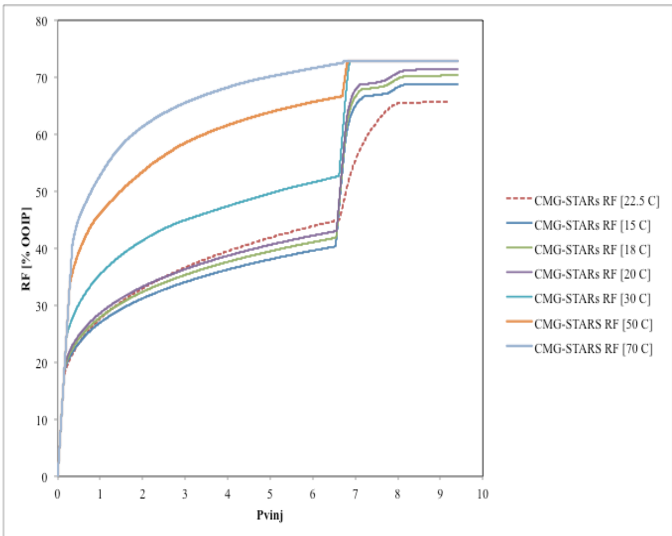

Fig. 12. Effect of temperature on the RF of 1 PV of Polymer slug.

C. Effect of Oil Viscosity on the RF

Several oil viscosities (4 cP to 100,000 cP) were investigated, to study the effect of AILP slug. Fig. 13 performs the cumulative oil production of different oil viscosities, and it is recognized that the sweep efficiency of pure brine flooding grows as the viscosity of oil viscosity declines. However, in the case of chemical slug performance, as shown in Table 4, the additional RF increases as the viscosity of oil rises from 4 cP – 5,000 cP. However, the efficiency of the chemical slug drops as the viscosity has grown from 5,000 cP – 100,000 cP.

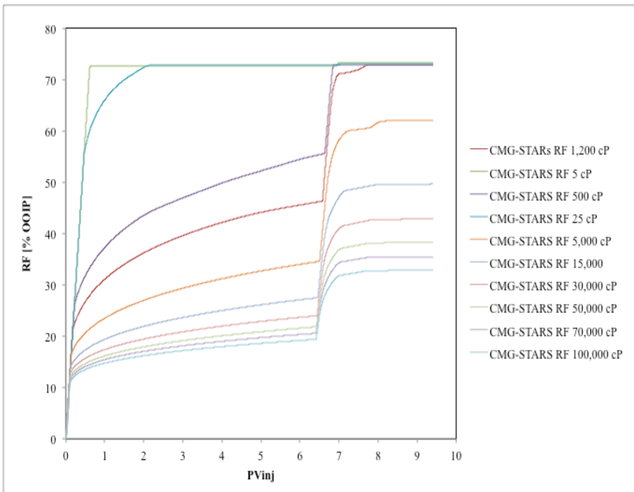

Fig. 13. Efficiency of chemical slug for different oil viscosities.

Table 4. Additional RF for different Oil viscosities.

Oil Viscosity, cP	Additional RF[% OOIP]
5	0.485
25	0.259
500	17.52
1,200	26.66
5,000	**27.49**
15,000	18.89
30,000	14.47
50,000	11.75
70,000	10.17
100,000	8.8

D. Effect of Chemical Slug Initiation Time on the RF

This section covers the performance of Polymer slug injection. The early the injection of 1 PV Polymer slugs the higher is RF. In this simulation work, the Polymer injection times are considered in three various cases as shown in Table 5. Polymer flooding is designed to start at 3.3 PV for Case 1, after 4.8 PV of brine flooding for Case 2, and 6.6 PV for the third Case.

Fig. 14 and Table 5 show that the cumulatively produced oil is not responsive to Polymer introduction time. However, Polymer injection time controls the consumed amount of the displacing fluid to approach the greatest RF. It is found that the immediate the Polymer occurs; the less displacing liquid is required, and the better additional RF is obtained. Table 5 expresses the relationship between Polymer injection times, the volume of displacing fluid, and extra RF. From the economic perspective, the introduction of the Polymer slug should begin early in the flooding process.

Table 5. Cumulative and additional RF with respect to the injection time.

At PV	RF_T [% OOIP]	Additional RF [% OOIP]
3.3	66.75	29.18
4.8	66.66	25.24
6.6	66.11	21.10

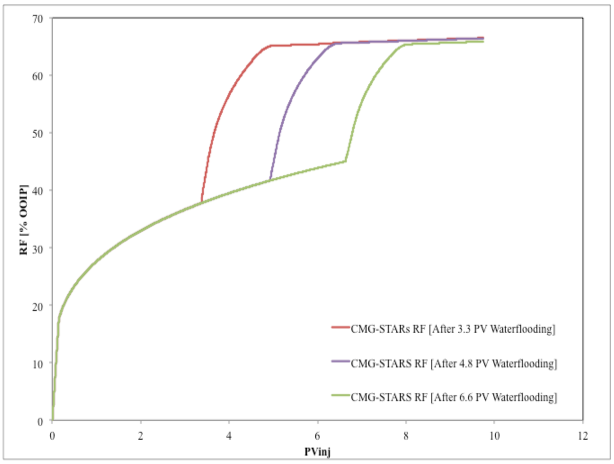

Fig. 14. Effect of slug injection time on the RF.

V. CONCLUSION

Chemical simulation techniques were employed to simulate and history match the results of four experiments. The matched results of injected PVs versus water cut, oil cut, pressure drop, and cumulative oil production curves revealed the ability of CMG-STARS to successfully history matching by tuning oil-water relative permeability curves and the pure viscosity of the Polymer. In the case of introducing Polymer only or Polymer and other chemicals, the influence of the chemical slug on the water cut, oil cut, and pressure drop curves was more noticeable in the results of the simulator in comparison to the experimental data. On the other side, the outcomes show the effect of altering relative permeability curves, pure Polymer viscosity, temperature, and changing the oil properties. The results demonstrate that including the Polymer in the displacing phase increases the sweep efficiency by limiting the mobility ratio.

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NOMENCLATURE

[EMIM][Ac]	1-ethyl-3-methylimidazolium acetate
Ka	absolute permeability, md
Kro	oil relative permeability
Krw	water relative permeability
NaCl	sodium chloride
PHPA	partially hydrolyzed polyacrylamide
ppm	part per million
PV	pore volume, cm^3
PV_{inj}	injected pore volume
RF	recovery factor, % OOIP
Greek	
$\emptyset$ =	porosity, %

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