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Enhanced Oil Recovery by Alkaline-Surfactant-Polymer Alternating with Waterflooding

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Alkaline-Surfactant-Polymer (ASP) flooding is an efficient method but was poorly applied in the industry as it is costly. The best mixture and injection sequence is also uncertain. The objective of this research work was to determine the best injection design pattern which could reduce the cost while improving recovery via the conventional ASP flooding. The effects of different ASP techniques in terms of injection sequence and mixture on ultimate oil recovery were analysed. In the laboratory work, three types of chemical flooding injection design were evaluated namely, continuous or conventional ASP flooding, alternating ASP with waterflooding, and lastly tapering water to ASP ratio. The recovery for each cycle was recorded and the ultimate recovery was compared. The experimental results showed that ASP alternating with waterflooding gave the best ultimate recovery (68 %), followed by tapering water to ASP ratio (62 %) and continuous ASP flooding (57 %). The ratio of recovery per volume of chemical injected showed that ASP alternating with waterflooding is the best option as it uses the least chemical to yield a higher recovery. The ASP alternating with waterflooding should be considered for field application as it can give the best performance with higher ultimate recovery.

1. Introduction

The common primary oil recovery factor ranges from 20-40 %, with an average around 34 %, while the remainder of hydrocarbon is still not producible in the reservoir (Satter et al., 2008). Secondary recovery involves the introduction of water or gas into an oil reservoir. This process would only recover a further of 10 % to 30 % of the original oil in-place (OOIP) (Romero-Zerón, 2012). On average, the recovery factor after primary and secondary oil recovery operations is between 30 and 50 % (Green and Willhite, 1998). Hence, leaving tons of oil yet to be recovered. A tertiary recovery is introduced which is widely known as Enhanced Oil Recovery (EOR). It is a more complex and costly method to further recover residual oil. Due to the cost of EOR, the right method should be chosen from a wide range of choices prior to its implementation in the field. One of the most promising methods available is chemical flooding which includes alkaline, surfactant, and polymer flooding. These chemicals are effective as results from the synergy formed between them (Kusumah and Vazques, 2017). Alkaline-surfactant-polymer (ASP) flooding is a combination of chemicals injected to obtain the best possible recovery by altering both the displacement and sweep efficiencies. As a result, the recovery factor increases significantly when the displacement and sweep efficiencies are high. There are numerous ongoing ASP flooding projects worldwide, and the ASP flooding implemented in Daqing field, China is considered one of the largest projects (Manrique et al., 2010). However, as the costs incurred for chemicals are high, it may not be feasible for all types of reservoirs. The research work focuses on improving the technique in applying ASP flooding to a reservoir so that it can be cost and recovery efficient. Today, there is still uncertainty on the most proficient technique to accomplish ASP flooding in terms of mixture ratios and sequences of injection ASP and the right formulation can lead to a better recovery.

2. Alkaline-Surfactant-Polymer (ASP) flooding

The ASP flooding is one of the main methods in chemical enhanced recovery. Similar to other chemical EOR, ASP is used to improve the mobility ratio and increase the capillary number, mainly by making the interfacial

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tension (IFT) between the displacing and the displaced phases small, usually by about 1,000 folds (Thomas and Ali, 2011). This type of flooding is a combination of chemicals that can be considered as a perfect solution to improve mobility ratio and capillary number. Thus, this method can enhanced the oil production with the improvement of both the sweep and displacement efficiency (Hillary et al., 2016). Alkali is one of the main components in ASP flooding and it is used to reduce the adsorption of the surfactant on the reservoir rock. It creates an in-situ surfactant due to the alkali reaction with the acidic oil. This in-situ surfactant and the injected surfactant can reduce the interfacial tension (IFT) to ultralow values hence reducing the capillary number and the trapped oil can be produced (Rieborue et al., 2015). Generally, surfactant is expensive and it is not feasible if the adsorption rate was very high. This would result in the mobilization of immobile oil and preventing oil trapping (Liu et al., 2008). According to Singh et al. (2017), it is found that ASP flooding is a more cost-effective alternative to the conventional micellar-polymer flooding. Due to the similar properties of alkali and surfactant that can reduce the IFT, the combination of those two chemical will be in favour to reach the goal of ultralow IFT. One of the well-known functions of polymers is to increase the viscosity of displacing fluid hence, improve the sweep efficiency. Furthermore, polymer can also ensure a good mobility control for the flooding thus ensuring increase in sweep efficiency (Rieborue et al., 2015). It also has a special property called polymer viscoelastic behaviour where it can exert a larger pulling force on oil droplets or oil films due to the stress at the surface between oil and polymer. Over time, the force increases until it reaches a point where the force generated is powerful enough to remove oil from unrecovered pore thus, residual oil saturation is decreased. Overall, ASP flooding is expected to recover between 16 to 19 % from the original oil in place (Taiwo et al., 2016).

3. Materials and method

3.1 ASP Experimental Setup

Sandstone in a specific size is chosen as the core sample in this study to simulate reservoir rock. For the model, the internal diameter and length was 0.25 cm and 120 cm, and due to the length of the model. An automated precision metering pump was used to pump the intended fluids inside the test section. The model of the pump used was Quizix QL-700 Series which was equipped with two cylindrical pumps that worked alternately. This pulse-free pump can pump fluid from either direction at a constant rate, pressure or differential pressure based on requirements. The experimental setup is as shown in Figure 1.

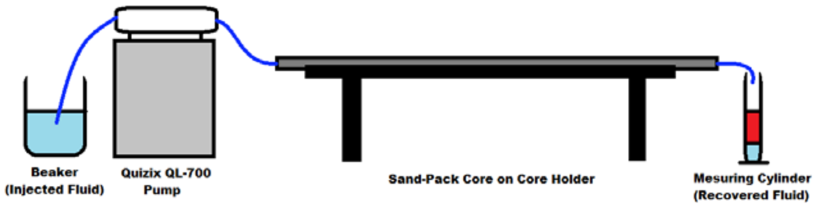


Figure 1: Schematic of experimental setup for ASP flooding with three injection design.

Prior to initiating the experimental work, the injection pattern with the desired PV of injected fluid was determined. The waterflooding, pre-slug, main-slug, and post-slug were injected accordingly into the sand pack model in order to vary the pore volume. The amount of fluid exited was measured and recorded to obtain the recovery per pore volume.

3.2 Fluid properties

The fluid used in this study was a high viscous paraffin oil which represented crude oil. This study utilized a simulated formation water consist of sodium chloride (NaCl) as brine. The salinity was 15,000 ppm in accordance with the salinity of NaCl equivalent at the Central Malay Basin (Heavysege, 2002). Table 1 is the summary for the simulated formation water and oil used. The simulated oil was considered viscous and it fitted the characteristics of ASP which was better in displacing heavier oil. According to Brian (2003), heavy oil is produced more efficiently from ASP flooding compared to normal chemical flooding alone.

Table 1: Details of simulated fluids

Type of Fluid	Chemical Composition	Density (g/ml)	Remarks
Brine	NaCl	1.03	15,000 ppm (Salinity)
Oil	Paraffin	0.856	30 cp (Viscosity)

3.3 Injection rate

A typical flow rate in normal reservoir is 2 ft/d, which is equal to 7.0556 x10^{-6} m/s. The field application value must be converted into a new lab scale value in order to simulate a real operation. From calculation, the obtained value for lab scale injection rate was 0.1 cm^3/min.

3.4 Injected chemicals

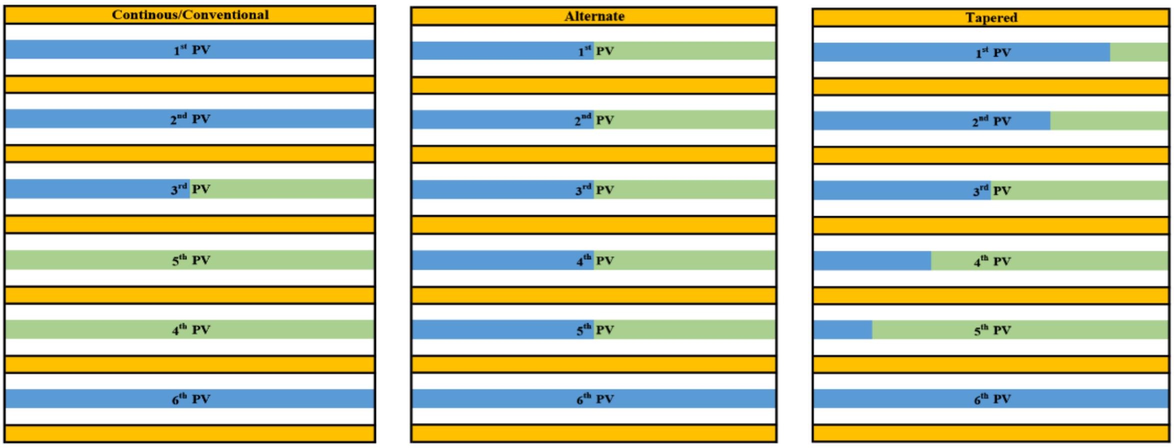
Generally, chemical flooding processes involves three phases of slugs which are pre-slug, main slug and post-slug. The pre-slug was where small portions of low concentrated polymer were used as the front end of chemical flooding. This is then followed by a sloppy ASP chemical main slug composing of alkali, surfactant and polymer. The chemical for alkali is considered strong where it is much more effective compared to a weaker alkali such as sodium carbonate (Na_2CO_3) (Guo et al., 2017). Sodium hydroxide is not only used in laboratory works, but also in the field where it has strong emulsification ability and can form wider surfactant range. This enables it to meet the requirements of ultralow interfacial tension (IFT) (Guo et al., 2017). Table 2 shows the concentration of chemicals used in this experimental works. The post-slug was the last phase of injection where the concentration of polymer was lower than in pre-slug. Post-slug acts as the protector for the ASP main slug and prevents fingering effect cause by chase water.

Table 2: Concentration of utilized chemical

Category	Chemical	Composition	Concentration (wt.%)
Pre-Slug	Polymer	Hydrolysed Polyacrylamide	0.1
	Polymer[1]	Hydrolysed Polyacrylamide[1]	0.03[1]
Main-Slug	Alkali[2]	Sodium Hydroxide[2]	0.5[2]
	Surfactant[3]	Sodium Dodecyl Sulphate[3]	0.13[3]
Post-Slug	Polymer	Hydrolysed Polyacrylamide	0.05

3.5 Injection Pattern

The injection pattern for continuous/conventional ASP flooding starts with the injection of 2.5 PV of waterflooding, followed by EOR process with the introduction of another 2.5 PV of ASP flooding. Then, chase water of 1 PV was injected before it was terminated, thus the total injection of 6 PV was recorded as shown in Figure 2(a). Figure 2(b) shown the injection pattern for alternating ASP with waterflooding, the injection starts with 0.5 PV waterflooding. EOR process took place with the injection of another 0.5 PV of ASP flooding. The waterflooding alternated with low concentration of ASP was continued until it reached 5 PV, then it will be followed by 1 PV of chase water. Lastly shown in Figure 2(c), for tapering water to ASP ratio, the first cycle starts with, 0.83 PV of water was injected at a rate of 1 cm^3/min, followed by ASP of 0.17 PV which totalling 1 PV for one cycle. The second cycle, 0.67 PV of water was injected at the same rate while ASP was injected at a PV of 0.33. For the third cycle, the volume of water injected was the same as ASP flooding, which was 0.5 PV each. The fourth and fifth cycle were designed using reversed ratio of the first and second cycles. As shown in Figure 1, all of the injection patterns was followed with 1 PV of chase water, where it is a standard practice used for most of ASP flooding projects (Ghorpade et al., 2016).



(a) (b) (c)

Figure 2: Injection patterns schematic for (a) continuous/conventional ASP, (b) Alternating ASP with waterflooding and (c) tapering water to ASP ratio.

4. Results and discussion

4.1 Continuous/Conventional ASP flooding

This injection design represents the typical ASP flooding. The process started with the injection of waterflooding first for 2.5 PV before EOR was initiated. It followed by the injection of 2.5 PV chemical flooding and 1 PV of chase water. Figure 3 shows that ASP flooding was used as secondary recovery after waterflooding where the blue background represents the waterflooding while green background represents the ASP flooding. The waterflooding of 2.5 PV was taken from previous experimental work. It can be observed that the waterflooding of 2.5 PV produced a recovery factor of approximately 50 % with the total final displacement of 57 % for the whole run. The follow-up ASP flooding produced an additional 7 % recovery after a static 50 % recovery recorded by waterflooding. This shows that ASP does gives increase in recovery even for this scale experimental work which only utilize sand pack model. This can validate that the sand pack and chemical composition used is suitable for this experiment.

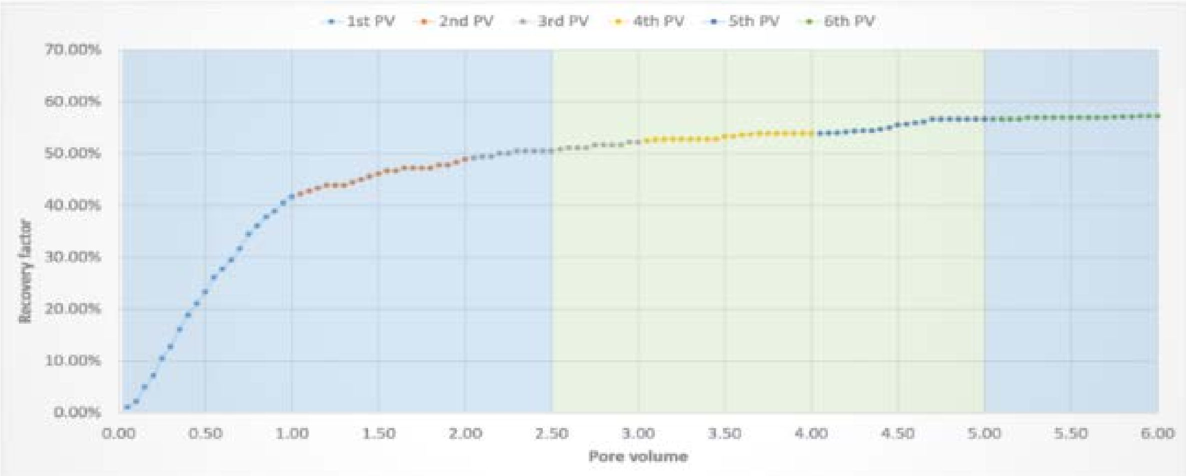


Figure 3: Recovery factor vs injected pore volume for continuous/conventional ASP flooding.

4.2 Alternating ASP with waterflooding

This injection design was the first to utilize the injection of ASP flooding in a sequential base while alternating with waterflooding. The process started with the injection of waterflooding of 0.5 PV followed by 0.5 PV of ASP flooding thus completing a ratio of 1:1 for waterflooding and ASP flooding of 1 PV. The sequence was continued in an alternating fashion until it reached the 5th cycle before 1 PV of chase water was injected as a final displacement to push the oil and chemical out. The results are shown in Figure 4 with blue background represents the waterflooding while the green background represents the ASP flooding. ASP flooding was run immediately after a minor waterflooding process of 0.5 PV. Results showed that the flooding of chemicals started to show signs of recovery right after they were injected. This proves that ASP flooding acted as the recovery enhancer. On the last run, after the 6th and last PV, the recovery recorded was 68 %. The recovery increment was small after 1.7 PV after realizing a quick and high recovery of oil in the early stages of EOR. The decreasing rate later was due to the rapid recovery in the first 1.5 PV which then resulted in a high IFT between the oils that are not recovered in the sand pack model.

4.3 Tapering water to ASP ratio

This tapering injection design refers to the increment of ASP slug size rather than increment of ASP concentration. The process started with a 1:6 ratio of ASP flooding to waterflooding. Progressively, the ratio between ASP and waterflooding increased until the 5th PV where the ratio of 5:6 of ASP to waterflooding was obtained. This can be seen in Figure 5 with the blue background representing the waterflooding while the green background represents the ASP flooding. It can be seen that the recovery factor curve is similar to the alternating injection design where the ASP flooding was run immediately after a minor waterflooding of 0.83 PV. It is observed that after 1 PV, the recovery was 46 % with the ultimate recovery of 62 %. The recovery was better when EOR was implemented in the early process. The introduction of such ASP technique has successfully reduced the interfacial tension thus reducing the amount of immobile oil in the sand pack model. When compared with alternating, tapering gave a slower start in recovery factor especially in the first half of the total 6 PV injected but picked up quickly in the last 3 PV due to smaller amount of ASP injected at start.

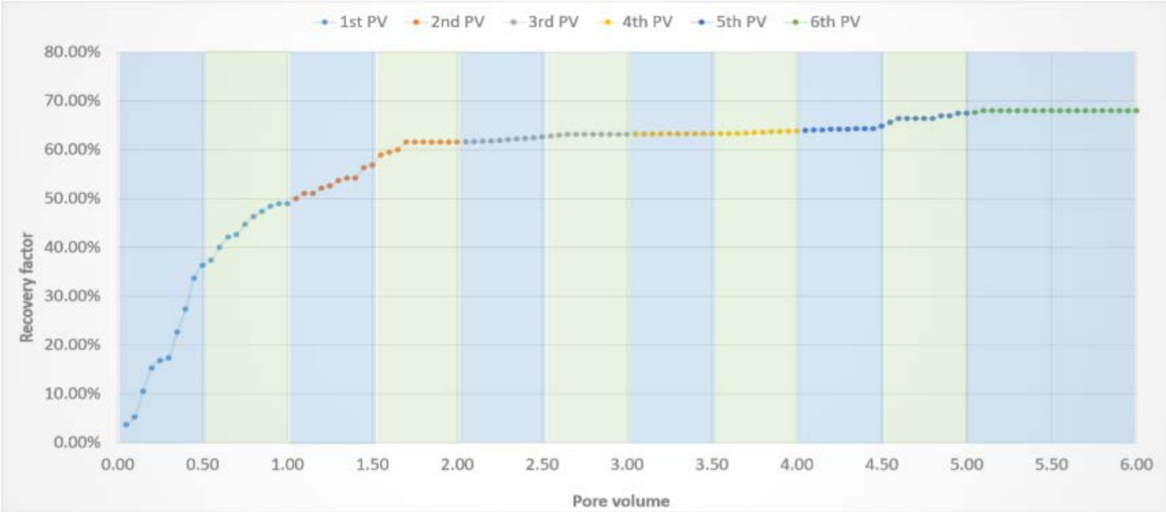


Figure 4: Recovery factor vs injected pore volume for alternating ASP with waterflooding

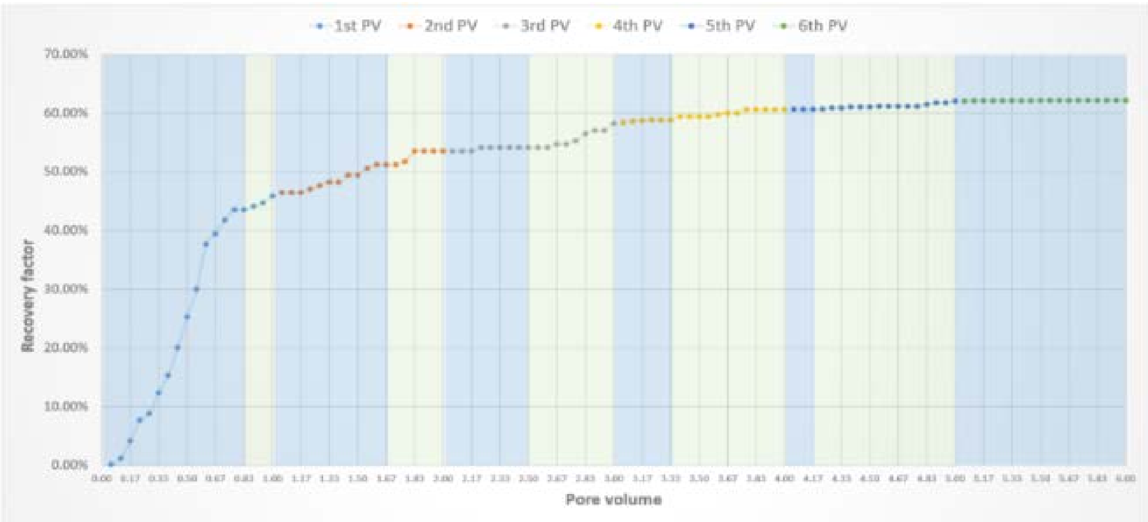


Figure 5: Recovery factor vs injected pore volume for tapering water to ASP ratio.

4.4 Chemicals' Usage

The feasibility study in any EOR project is significant in order to gain the best return of investment. Table 3 lists the amounts of chemicals used in each injection design.

Table 3: Comparison of recoveries per chemical injected.

Injection Design	PV injected (%)	ASP Slug (wt. %)			Total Chemical Injected				Recovery (%)	Recovery per Chemical Injected
		A*	S*	P*	A*	S*	P*	Total		
Alternating	250				125	32.5	7.5	165	68	0.41
Tapering	250	0.5	0.13	0.03	125	32.5	7.5	165	62	0.37
Continuou s	350				175	45.5	10.5	231	57	0.25

*A=Alkali, S=Surfactant, P=Polymer

The results show the ratio of recovery per chemical used which described the efficiency of the chemical in every injection. Based on the results, the injection design that produced the highest recovery was alternating with 68 % followed by tapering with 62 %, and lastly continuous with 57 %. This showed that alternating injection design was better than tapering and continuous injection design. The ratio of recovery per chemical injected for alternating was also the highest with 0.41 compared to tapering and continuous with 0.37 and 0.25 respectively. This means that alternating injection design was able to recover more oil with lower chemical usage. From technical feasibility views, alternating injection design gives the best option not only in term of recovery but also in term of the minimum chemical usage.

5. Conclusions

The chemical mixtures of alkaline, surfactant and polymer proved to be efficient because they cancel out each other's disadvantages hence creating a mixture of chemicals that were able to recover more oil. The study revealed that the best injection design which gave the highest ultimate recovery was alternating ASP with waterflooding compared to conventional and tapering injection technique. The improvement in recovery percentage was due to the early implementation of EOR process instead of being a secondary or tertiary recovery. Furthermore, with early implementation of EOR, the sand pack model was conditioned much earlier which subsequently improved the recovery. Other than that, the ASP successfully reduced the interfacial tension much earlier in tapering and alternating compared to continuous which may have been full with immobile oil. The sloppy slug implemented in this study was efficient and easy to be implemented compared to other simultaneous injection of ASP thus can be considered as a good slug mixture in the field.

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