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Feasibility Study of Alkali–Surfactant–Polymer Flooding On Enhancing Heavy-Oil Recovery in a Heterogeneous Thin Reservoir

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Abstract

This study presents the feasibility of chemical flooding in a thin heavy oil reservoir using numerical simulations. The effects of heterogeneity in sweeping efficiency were partly investigated through the oil saturation at predefined sections. After that, the optimizations of two most representative flooding schemes were carried out considering the variation of oil price at a specific expensing condition. The profiles of oil saturation indicated a dominant swept layer where the horizontal wells were located regardless the higher permeability of other layers. In other words, fluid flow is not uniform even in a thin formation. The optimization results of two considering ASP schemes at a specific economic condition figured out the best flooding scheme by mean of comparing net present values (NPV), in particular the referenced consideration of oil prices substantially demonstrated the full feasibility of that ASP injection scheme in a given heavy oil characteristic even though the sweeping flows seemed to not be expectedly favorable in the reservoir.

Keywords: chemical flooding; ASP; feasibility; heavy oil; response surface; oil price

INTRODUCTION

Utilization of chemical flooding is becoming an attractive feasible method for recovering a large volume of heavy oil when the traditional thermal methods are not suitable in thin pay-zone reservoirs or when overlying permafrost exists [1,2]. Combined alkali-surfactant-polymer (ASP) injection is one of the most popular applications among other flooding sequences for light oil and heavy oil recovery. While the employment of polymer aims to improve the sweep efficiency as a result of properly controlling the mobility of the displacing fluids, alkali and surfactant are considered as the most effective agents in reducing the interfacial tension (IFT) between oil and water (O-W) [3-6]. Many previous works have demonstrated the successful ASP injection plans by injecting a single chemical slug or a flooding sequence to thoroughly extract the crude oil from the pores. Theoretically, the simultaneous injection of alkali and synthetic surfactant with polymer solution will increase the displacement efficiency as a result of reducing IFT to the ultralow value by micro-mechanism and enlarging the swept area by properly controlling the mobility ratio, thereby enhancing the ultimate oil recovery [7-10]. However, the buffering fluid after the first ASP slug is always of concern as it significantly supports the movement of the oil bypassed by the first slug.

Even though the enhancement in heavy oil production induced by chemical flooding has been performed in several practical EOR projects, the effects of heterogeneity on the fluid flow profiles are still disputed, especially when the oil bearing formation is too thin to consider. As the chemical flooding is mostly appropriate to deploy in thin heavy oil reservoir due to the impossible employment of thermal methods, the quantitative impacts of heterogeneity on the sweep efficiency are of importance to verify no matter how the thickness of the formation is. Further, since the large scale profiles of fluid flow might not be observed in core flooding process or in the porous media underground, using state of the art simulator such as CMG or ECLIPSE appears to be necessary and appropriate for evaluation in reservoir conditions [11]. Thanks to the development of numerical study, chemical flooding for EOR simulation has been demonstrated as credible and highly accurate that is obviously favorable for manifestation in a large scale reservoir [12].

This work first verifies the impacts of heterogeneity in sweep efficiency of ASP flooding in a heavy oil reservoir by simulation as heterogeneous permeability plays a key role on fluid flow in the reservoir which determines the oil sweeping efficiency [13]. Both the injector and producer are horizontal wells installed in the near-bottom layers owing to the high productivity [14]. Various ASP injection schemes will be operated to figure out the most effective one which is most profitable based on a given range of oil prices. Finally, an optimization using a specific mathematical tool is carried out for the most efficient scheme in term of chemical design, the comprehensive feasibility of the process is concluded afterward based on the NPVs at various oil prices. The essential findings implied from numerical results of this study will elucidate the sweep patterns of fluid in the heterogeneous thin formation and the feasibility of employing an ASP injection on recovering heavy oil in such a reservoir at varied market conditions.

LITERATURE REVIEW

Atsenuwa et al. classified heavy oil types with viscosities ranging from 50 to 50000 cp and pointed out that the capillary force between water and heavy oil is higher than that between water and conventional light oil [15]. Asghari and Nakutnyy carried out experiments about using polyacrylamide to extract heavy oil, and concluded that a higher 5000 ppm polymer solution is expected to effectively recover oil when the injection rate of the polymer is less than 30 m^3/day [16]. Nevertheless, by using polymer to recover different oil samples with viscosities of 2000–5000 cp by coreflood tests, Levitt et al. observed an insignificant increase in the recovery factor when the solution viscosity altered from 3 cp to 60 cp [17]. In terms of offshore heavy-oil reservoir, Xiaodong and Jian presented the main problems of EOR technology and concluded that water salinity is the most important factor that affects the success of polymer flooding processes [18]. Using a streamline-based simulator to investigate the design of polymer flooding, AlSofi and Blunt suggested that the optimal flooding design in terms of concentration, slug size and initiation is more intuitive than earlier expected; they also determined that polymer solution should be injected before any water flooding to achieve the best outcome [19]. In contrast, Zhou et al. investigated various chemical flooding sequences and pointed out the importance of a second polymer slug after any chemical injection with a water volume in between [20]. They also concluded that the reduction of water mobility plays a main role in improving the heavy oil production, and polymer concentration of the second slug is an essential factor to recover more oil with a water slug in between. Even though coreflood tests in laboratory are mandatory before deploying in the field, Saboorian-Jooybari et al. argued the unreliable estimation in oil recovery by coreflood for the field scale; they highlighted that the most important point of a successful polymer flooding process must be derived on the basis of the screening procedures from either technical or economic feasibility [21].

Dong et al. investigated the displacement mechanisms of alkaline–surfactant flooding by using a glass micromodel, they observed a significant mitigation on water channeling following the formation of water-in-oil (W/O) emulsion [22]. In contrast, the addition of synthetic surfactant to an alkaline solution could form an oil-in-water (O/W) emulsion, which makes the heavy oil droplets moveable. Theoretically, the employment of alkali aims to generate the in-situ surfactant as a consequence of a reaction with the natural acid components of oil and to partly alter the rock wettability [23-25]. Pei et al. proved the strong effect of the IFT on heavy-oil properties having low acid number compared to high acid number [26]. In their experimental studies, they also determined the cost-effective EOR process of utilizing alkaline flooding for an acidic heavy-oil reservoir; Na_2CO_3, in particular, performed better than NaOH in terms of lowering the IFT. Basically, the employment of alkali, surfactant, and polymer in an appropriate design helps to drastically improve heavy-oil production rather than a single-agent design [27-29]. Indeed, combined ASP flooding was demonstrated to be more attractive than SP flooding by Bataweel and Nasr-EI-Din in terms of achieving the lower IFT and higher sweep efficiency [30].

In terms of optimization, Zerpa et al. evaluated optimization algorithms for surrogate models in various scenarios of ASP flooding in the light oil field with target function was oil recovery factor; they justified the use of multiple surrogates for identifying alternative optimal solutions corresponding to different regions of the design space [31]. Furthermore, the optimization by response surface approach for ASP flooding proposed by Zerpa et al. proposed a reduction of chemical slug size in comparison with the suggested volume from a laboratory design [32]. Similarly, a response surface has also been considered to optimize the utilization of alkali and surfactant in the clastic reservoir of the Angsi field in Malay basin, as reported by Ghadami et al. [33]. They concluded that it is not necessary to account for all of the unimportant parameters in sensitivity analysis; instead, only consider the effects of the chemical design parameters such as the concentrations, initiation times, and sizes.

CASE STUDY

A quarter five-spot 3D reservoir model of a specific heterogeneous reservoir is built in the STARS simulator. The porosity alters from 0.28 to 0.35 throughout the reservoir, whereas the permeability decreases downward and is also inhomogeneous in each layer. The reservoir size of 114 × 114 × 10.5 m^3 is designed in Cartesian coordinates with size for each cell is 3.8 × 3.8 × 2.1 m^3. The other reservoir parameters and fluid properties are presented in Table 1. The initial setup conditions of the reservoir were partly obtained from the work of Xiaodong et al. [18]. The reservoir model has totally 5 different permeable layers with the descendent permeability from layer 1 (at top with highest permeability) to layer 5 (at bottom with lowest permeability), and to horizontal sections of producing and injection wells are installed in layer 4.

In terms of the wettability, the reservoir rock is assumed to be a water-wet rock system with water saturation of 25% at the initial time, and only two phases (oil and water) are existing.

Table 1: Parameters used for the initial reservoir conditions.

Initial reservoir condition	Value(s)
Grid size	30 × 30 × 5
Cell size (m^3)	3.8 × 3.8 × 2.1
Thickness	10.67 m
Initial reservoir pressure	2.76 MPa
Reservoir temperature	21 °C
Porosity	0.28–0.35
Horizontal permeability	700–4000 mD
Fluid properties (at reservoir condition)	
- Initial oil saturation	0.75
- Oil gravity	12 °API
- Oil viscosity	1202 cp
- Residual oil saturation after water flooding	0.37
- Initial salinity of reservoir water	20,000 ppm

Artificial brine (or simply "water") is made by adding salt to the clean water. The salinity of the water is also considered for an efficient design since it contributes to the determination of the quality of the fluid emulsification as well as the viscosity of the polymer [34,35]. The strategies of the injection schemes are listed in Table 2. Principally, all sequences are initiated by a preflushing water and ceased by a post-flushing water injection. All flooding schemes will be initiated by a 6 months preflushing water, after that the main ASP slug is injected for 3 years and followed by a postflushing water or a second chemical slug.

Table 2: Injection strategies of flooding sequences.

Injection sequences	P	ASP
W-ASP(15)-W	-	3 years
W-ASP(20)-W	-	3 years
W-ASP(15)-P(15)-W	1 year	3 years
W-ASP(15)-W-P(15)-W	1 year	3 years
W-ASP(20)-W-ASP(15)-W	-	1st: 3 years 2nd: 1 year

W: water slug

ASP: combined alkali-surfactant-polymer slug

P: polymer slug

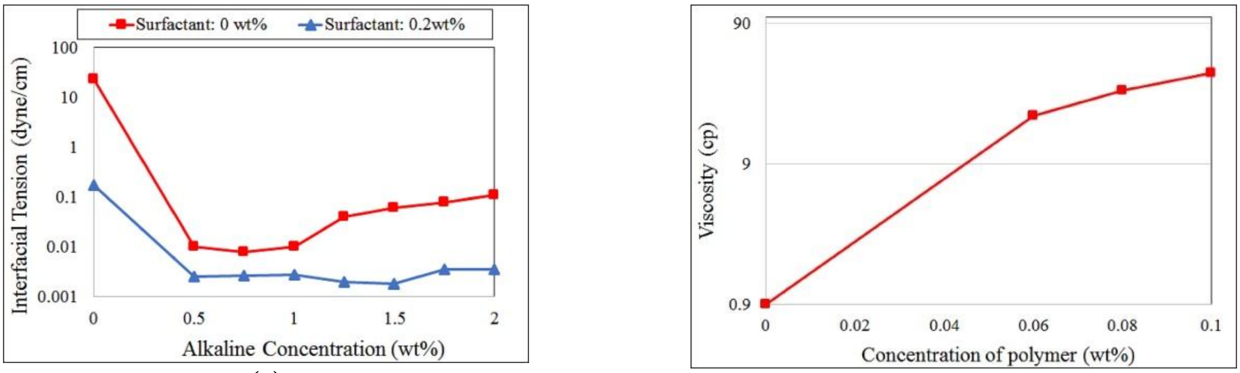
e.g. W-ASP(15)-W means the process is initiated with a preflushing water injection, after that is the injection of combined alkali-surfactant-polymer followed by a postflushing water injection.

Numbers 15 and 20 represent the viscosity of the solution, the detail is explained below.

The concentrations for the flooding terminology are designed as follows:

- Water flooding: complete water injection throughout the project.
- P(15) – 550 ppm polymer solution with a salinity of 10,812 ppm. 15 indicates the designed viscosity of the solution.
- P(20) – 690 ppm polymer solution with a salinity of 10,812 ppm. The designed viscosity of solution is 20 cp.
- ASP(15) – 2.12 vol% alkali combined with 0.132 vol% surfactant and 540 ppm polymer in a solution with salinity of 10,610 ppm. Initially, the fluid has viscosity of nearly 15 cp.
- ASP(20) – 2.12 vol% alkali combined with 0.132 vol% surfactant and 680 ppm polymer in a solution with salinity of 10,610 ppm. The viscosity of solution is 20 cp.

The final produced oil rate of 1.59 m^3/day is proposed to better compare the effectiveness of all sequences. The specific concentrations of the flood types were selected on the basis of the results of IFT measurements and the viscosity of the injection fluids. Figure 1 shows the chemical properties that are used for simulation studies including the IFT characteristics and the viscosity behavior of the chemical designs, as referenced from the practical report of Zhijian et al. [36].



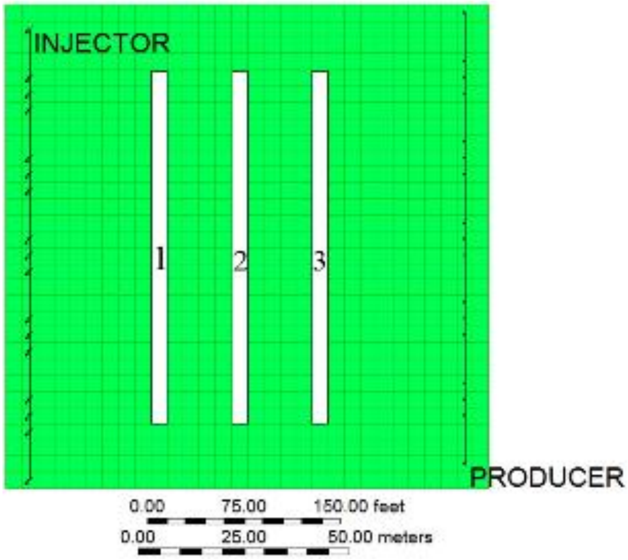
(**a**) (**b**)

Figure 1: Chemical properties used for the simulation: (a) IFT values of the alkaline solution and (b) viscosity behavior of the polymer solution.

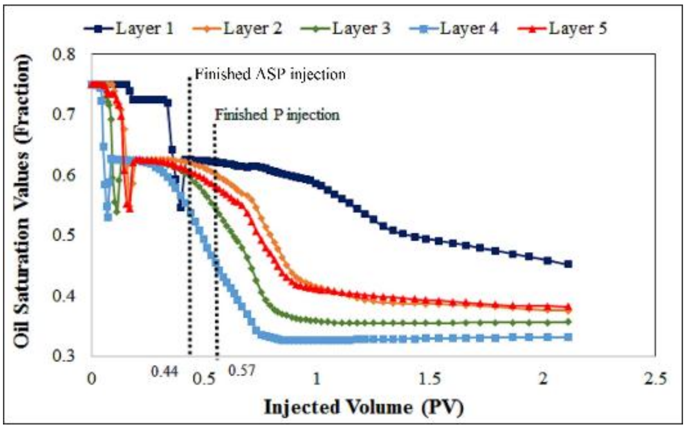
RESULTS AND DISCUSSION

Effects of Heterogeneity on Sweep Efficiency

Figure 2 shows the oil sweeping efficiency obtained through an investigation of the oil saturation values for sections 1–3 (Figure 2 (a)) in each layer, which obviously represents the oil saturation for the entire reservoir. As can be seen from the figure, the effect of chemical injection occurs at an early time for section 1 before the end of ASP and polymer injection, which indicates the high deviation in the oil saturation between layers. For sections 2 and 3, nearly equal oil saturation profiles are observed for each layer, even after the end of chemical injection; particularly, this situation continues until the total of 1 PV of fluids has been injected for the fluids to reach section 3. Further, the oil saturation rapidly decreases after an additional amount of approximately 0.5 PV of water is injected with dissimilar levels for each layer; layers 3 and 4 have lower oil saturation values than the others and maintain a relatively low level until the end of the process. The results confirm the importance of suitable water injection for post-flushing the chemical slugs in order to push the oil bank more efficiently to the producing well [37]. Except for layer 1, the reduced oil saturation values of the layers exhibit relatively lower deviations between each other, demonstrating the successful application of ASP and single-polymer slugs in terms of generating a uniform oil swept profile and inhibiting the water channeling phenomenon. Finally, even though the reservoir consists of five different permeable layers, the fluids predominantly flow in the layer with the installed wells and its close neighbor, and a large amount of oil still remains in the highest permeable layer—layer 1. This evidently explains that the contribution of the multilayered system to the flooding performance in a thin heavy-oil reservoir is marginal, although the crossflow between layers has been improved by the shear-thinning behavior of the polymer [38].

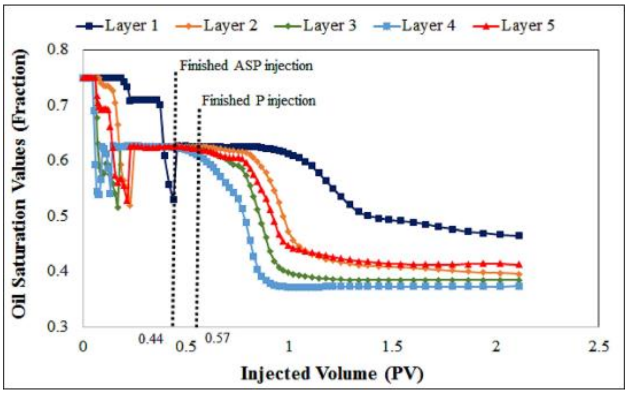


(a)



(b)

Figure 2: (Continued)



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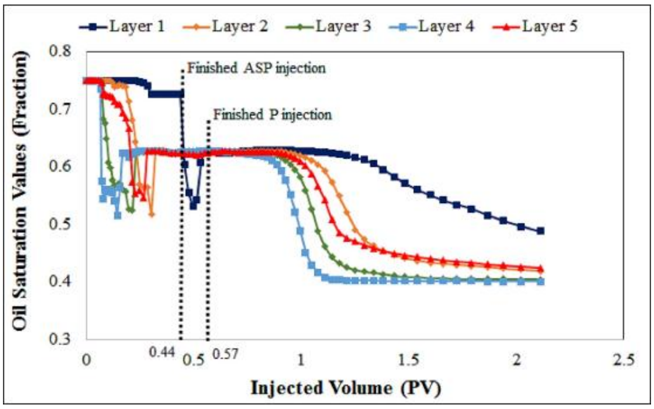

(d)

Figure 2: Investigation of oil sweeping efficiency through the oil saturation values of each section: (a) designated sections for the investigation, (b) oil saturation at section 1, (c) oil saturation at section 2, and (d) oil saturation at section 3.

Pre-assessment

The simulation results for various ASP flooding sequences substantially show that from a technical point of view, all injection schemes are favorable for deployment owing to the achievement of a high oil recovery compared to water flooding. Particularly, the repetition of an ASP slug with water injection between injection sequences might provide the highest amount of recovered oil, even though the increase in the amount of recovered oil is not significant. As presented in Figure 3, the uses of secondary chemical slugs could improve at least 2% in ultimate recovery factor, especially the injection of polymer right after the first ASP slug performs better than the case using a water slug in between. The figure also shows the obvious enhancement of chemical injection compared to water flooding, with the increase in oil recovery of about 15% for the same ending oil production rate.

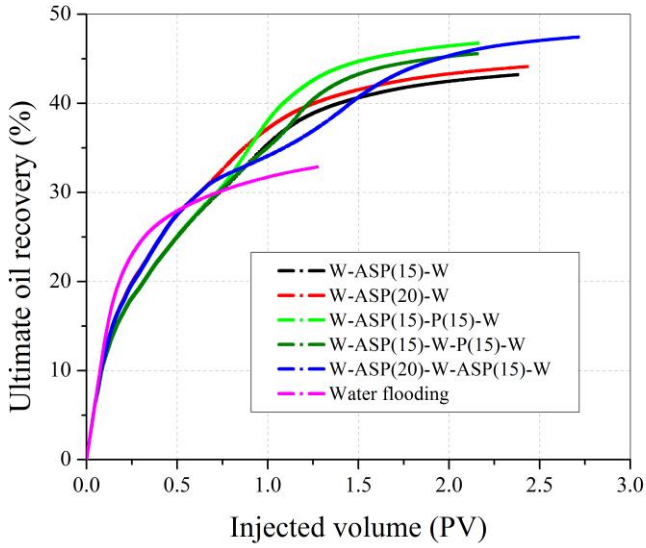

Figure 3: Performance in oil recovery factor of various ASP flooding schemes.

Nevertheless, for commercial purposes, it is necessary to determine the most predominant scheme by considering economic factors such as the oil price, chemical costs, or operation costs. The costs of these factors are referenced mainly from the work of Xiaodong et al. [18]. In detail, costs of alkali, surfactant, industrial salt and polymer are 1.32 \$/kg, 4.06 \$/kg, 0.033 \$/kg and 3.68 \$/kg, respectively, whereas chemical and water-treatment operation facility costs are \$140,000 and \$300,000, respectively. A range of oil prices is imposed on the basis of the practical historical and forecasted values from the U.S. Energy Information Administration (EIA) group, as shown in Figure 4. According to the realistic data, this work assumes a normal distribution for the oil price with minimum, maximum, and mean values of 30, 60, and 47 \$/bbl, respectively.

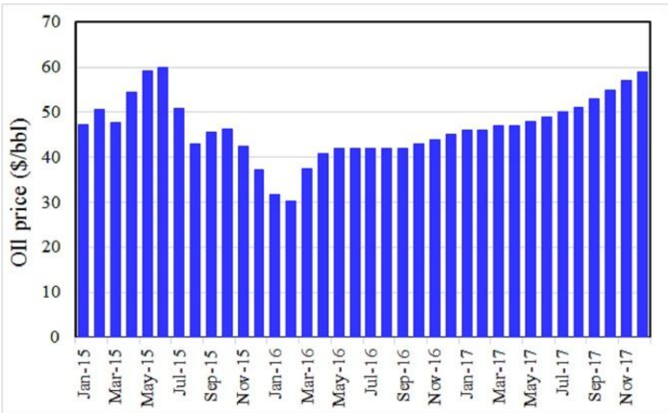

Figure 4: The historical and forecasted oil price as referenced from the U.S. Energy Information Administration (EIA) group.

All injection schemes are considered for the NPV calculation as the base cases in the pre-assessment stage in order to choose

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the most feasible one for the optimization processes in the next stage. From the results in Figure 5, the oil price considerably affects the choice of candidate for the EOR project. In detail, the W-ASP(20)-W-ASP(15)-W sequence is not the most relevant sequence, even though it has the highest cumulative oil production. Instead, when the oil price is less than 37 $USD/bbl, the W-ASP(20)-W sequence provides the highest NPV, and the W-ASP(15)-P(15)-W results in the best profit at a higher oil price. Therefore, both of these injection schemes should be chosen for the analysis of the optimization processes.

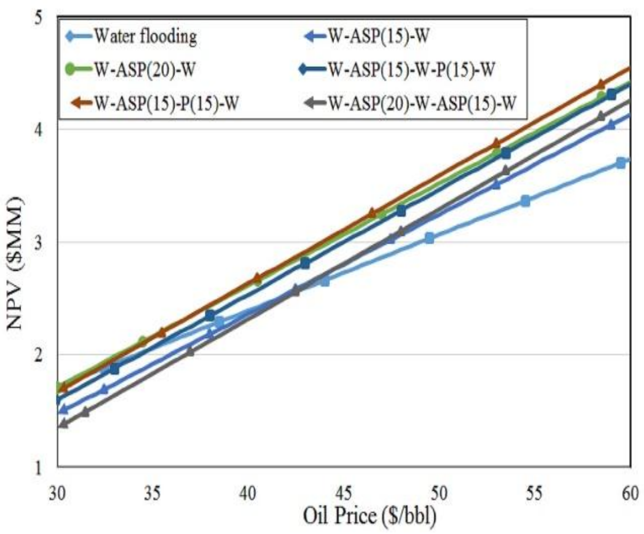


Figure 5: Computed NPV in pre-assessment stage for all possible chemical injection schemes.

Post-assessment

This assessment stage crucially presents the optimization procedures after obtaining the final chemical flooding sequence target in the pre-assessment process. Quadratic response surfaces are proposed to estimate the objective functions from the effective design variables. Typically, the final target NPV is regularly considered as an objective function [39]. However, since the probable oil price is taken into account, the recovery factor (RF) and the total chemical expense until the end of the project (CC), which are two important components that mainly determine the NPV, are analyzed in this study. First, RF and CC undoubtedly depend on decisive parameters such as the chemical slug size, chemical concentration, or operating conditions. Further, since the duration of the injection schedules and operating conditions are fixed, the total chemical slug sizes become dependent on only the chemical concentrations. Therefore, the employed agent concentrations are determined as the main variables for calculating the objective functions.

According to the change in the chemical concentration, the viscosity of the injected fluids will apparently be altered, and the base-case sequences can be generally renamed as W-ASP-W and W-ASP-P-W without mentioning the specific viscosity of the solution. For the W-ASP-W sequence, the objective functions are formulated as follows:

$$y = C_0 + C_1 a + C_2 s + C_3 p + C_4 n + C_{11} a^2 + C_{22} s^2 + C_{33} p^2 + C_{44} n^2 + C_{12} as + C_{13} ap + C_{14} an + C_{23} sp + C_{24} sn + C_{34} pn. \quad (1)$$

where *a*, *s*, *p*, and *n* are independent variables representing the concentrations in weight percent of the alkali, surfactant, polymer, and salt, respectively; C_x and C_{xy} are coefficients (x, y: 1, 2, 3, 4); and *y* represents the objective functions RF and CC.

For the W-ASP-P-W sequence, it is important that the polymer concentrations and salinity must be distinguished for the first and second chemical slugs since they are independently designed. Therefore, the response surfaces for this scheme are more complicated and require a higher number of coefficients, formulated as follows:

$$y = B_0 + B_1 a + B_2 s + B_3 p_1 + B_4 n_1 + B_5 p_2 + B_6 n_2 + B_{11} a^2 + B_{22} s^2 + B_{33} p_1^2 + B_{44} n_1^2 + B_{55} p_2^2 + B_{66} n_2^2 + B_{12} as + B_{13} ap_1 + B_{14} an_1 + B_{15} ap_2 + B_{16} an_2 + B_{23} sp_1 + B_{24} sn_1 + B_{25} sp_2 + B_{26} sn_2 + B_{34} p_1 n_1 + B_{35} p_1 p_2 + B_{36} p_1 n_2 + B_{45} n_1 p_2 + B_{46} n_1 n_2 + B_{56} p_2 n_2. \quad (2)$$

where the polymer and salt concentrations of the first and second slugs are p_1 and p_2 and n_1 and n_2, respectively. Table 3 presents the numerical ranges of the design variables and the base-case values. The polymer concentration is limited to 0.1 wt% as the threshold of the injectivity upon injecting the viscous liquid.

By simulation, a sample set with a total of 35 and 76 designs has been obtained for the W-ASP-W and W-ASP-P-W schemes, respectively. The results are analyzed by conventional matrix transformation and least-square methods to determine the coefficients of an individual response surface. The quality of the predicted values for the response surfaces is evaluated through the square numbers R^2, which reflects the accuracy of the models; specifically, a higher R^2 corresponds to a more reliable prediction. Figure 6 shows comparisons of the simulated designs and the predicted values of the response surfaces for both flooding schemes.

Table 3: Constraints on the design variables and their values for the base case.

Threshold	W-ASP-W				W-ASP-P-W					
	a	*s*	*p*	*n*	*a*	*s*	p_1	n_1	p_2	n_2
Max (wt%)	2.5	2	0.1	2	2.5	2	0.1	2	0.1	2
Min (wt%)	0.5	0.1	0.01	0.5	0.5	0.1	0.01	0.5	0.01	0.5
Base case (wt%)	1.36	0.503	0.068	1.061	1.36	0.503	0.054	1.061	0.055	1.081

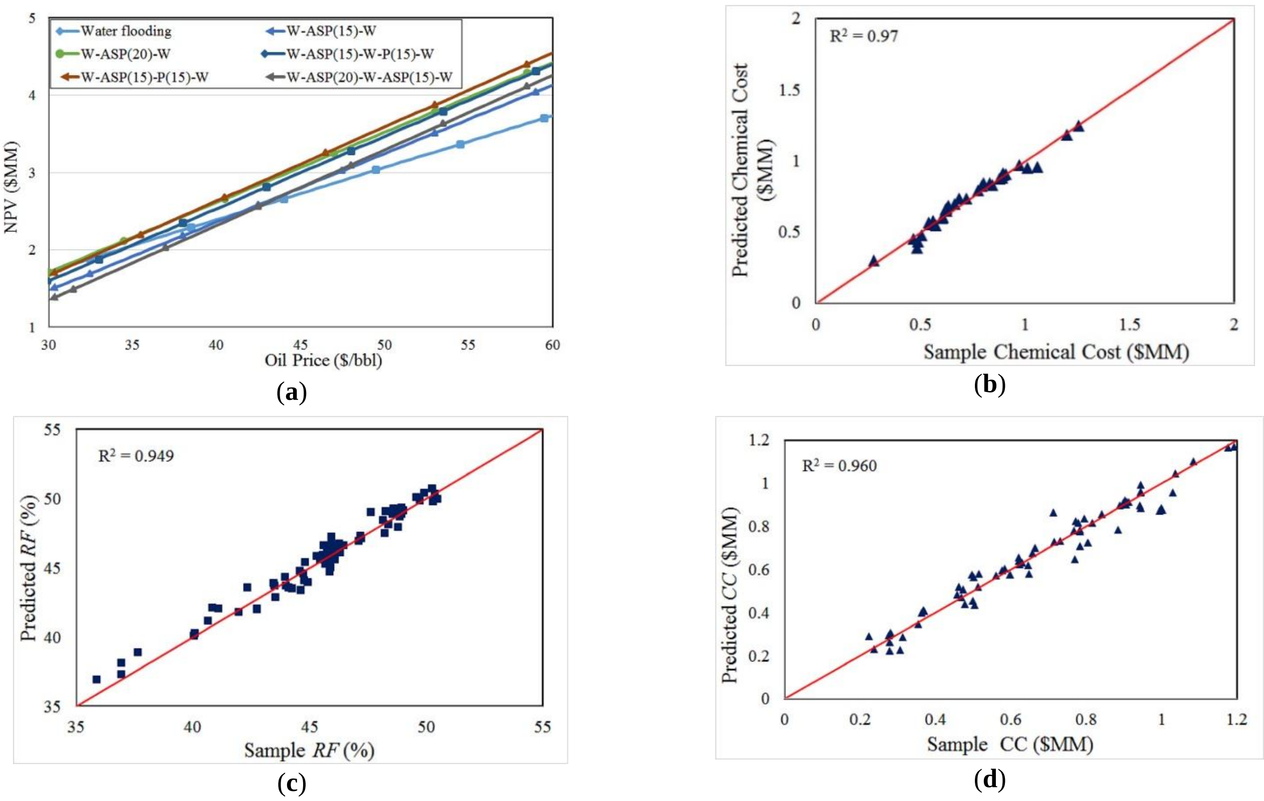


Figure 6: Estimation results of the oil recovery factor and total chemical cost: (a) oil recovery for W-ASP-W, (b) chemical cost for W-ASP-W, (c) oil recovery for W-ASP-P-W, and (d) chemical cost for W-ASP-P-W.

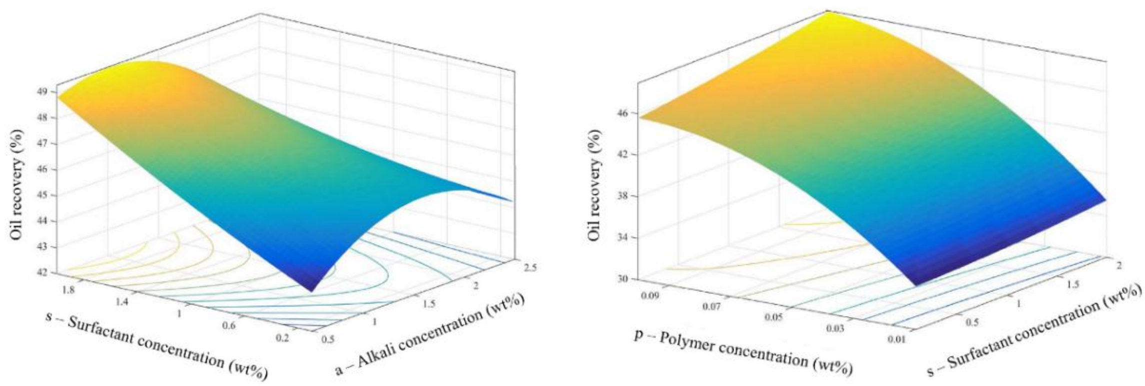
As shown in Figure 6, confidence levels greater than 97% are obtained for the estimation results for the oil recovery factor and total chemical costs for the W-ASP-W scheme, whereas the prediction for the chemical expense is more scattered for the W-ASP-P-W sequence. However, confidence levels greater than 90% are acceptable and can be used for further analysis. The computed coefficients of the response surfaces are listed in Table 4.

The relationships between the design variables and the recovery factors are shown in Figure 7. As can be seen in Figure 7 (a1), an increase in the surfactant concentration absolutely helps to improve the oil recovery, whereas the use of an alkali should be limited because the peak RF range corresponds to alkaline concentrations of 1–1.5 wt%. The increases in both the polymer concentration and salinity in the first ASP slug also enhance the cumulative oil production, corresponding with the increase in the surfactant concentrations (Figure 7 (a2, a3)).

However, when utilizing a buffering polymer slug, the first and second polymer concentrations do not proportionally and absolutely affect the oil recovery factor. As shown in Figure 7 (b1), RF reaches a peak value at approximately 60%, corresponding with the maximum constraint of p_2 and the minimum value of p_1. This manifestly affirms the critical contribution of the second viscous injected fluids to the EOR performance. From Figure 8, even though the polymer concentration of the first chemical slug is the factor with the greatest influence for the W-ASP-W scheme, it has much lower influence than the polymer concentration of the second slug in the W-ASP-P-W scheme.

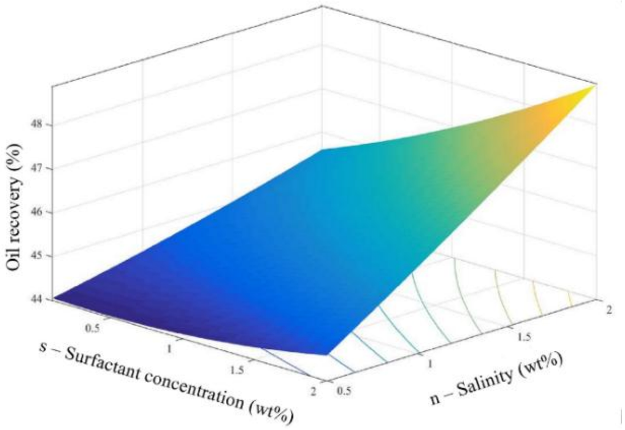
Table 4: Response surface coefficients for the W-ASP-W and W-ASP-P-W schemes.

Coef.	Value (*RF*)	Value (*CC*)	Coef.	Value (*RF*)	Value (*CC*)	Coef.	Value (*RF*)	Value (*CC*)
C_0	0.3082	0.5124	B_0	0.3128	0.8203	B_{13}	0.1495	-2.1106
C_1	0.0788	0.6944	B_1	0.0087	0.1073	B_{14}	-0.003	-0.0563
C_2	-0.002	0.807	B_2	0.1254	0.2187	B_{15}	0.06	-0.7043
C_3	1.4721	-18.5131	B_3	0.7035	2.4754	B_{16}	0.0004	0.0656
C_4	-0.0027	0.1938	B_4	0.0205	0.1438	B_{23}	-0.4491	2.227
C_{11}	-0.0179	-0.176	B_5	1.5941	6.2291	B_{24}	0.023	0.2672
C_{22}	0.0023	-0.2229	B_6	-0.0036	-0.5775	B_{25}	0.2259	2.2492
C_{33}	-13.4548	-125.696	B_{11}	-0.0024	0.0565	B_{26}	-0.0264	-0.2438
C_{44}	0.0013	-0.1496	B_{22}	-0.0283	-0.0935	B_{34}	-0.2299	-0.5783
C_{12}	-0.0113	-0.3192	B_{33}	-1.0632	-107.068	B_{35}	-9.5453	16.4692
C_{13}	0.2762	4.8088	B_{44}	-0.0155	-0.0395	B_{36}	0.3047	4.8562
C_{14}	-0.024	-0.0346	B_{55}	-3.3218	-110.531	B_{45}	-0.0911	-0.6072
C_{23}	0.1139	11.2661	B_{66}	-0.0085	0.1829	B_{46}	0.0187	-0.1759
C_{34}	0.0098	-0.0094	B_{12}	-0.0058	0.0381	B_{56}	-0.045	2.7402

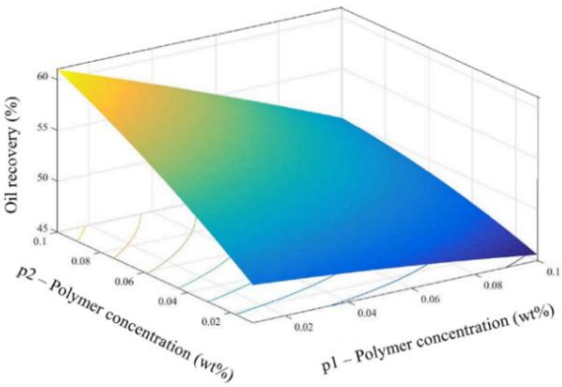


(**a1**) (**a2**)

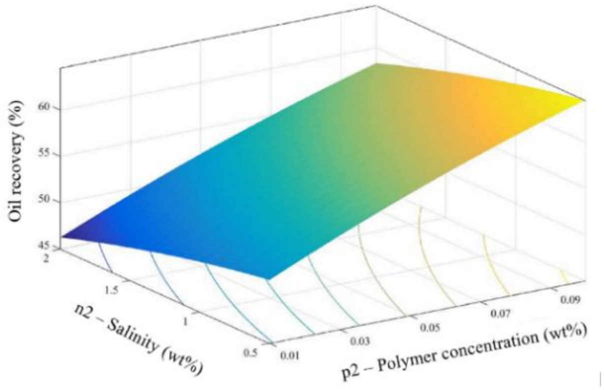
Figure 7: Continued …



(**a3**)

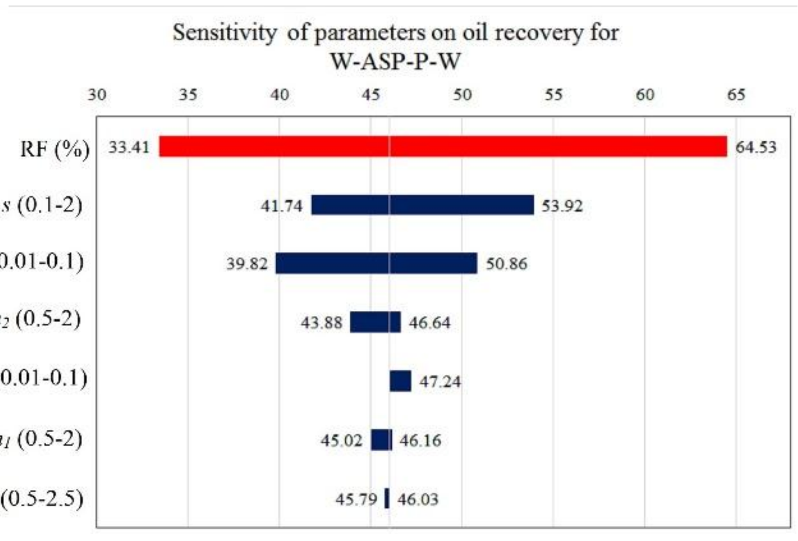


(**b1**)

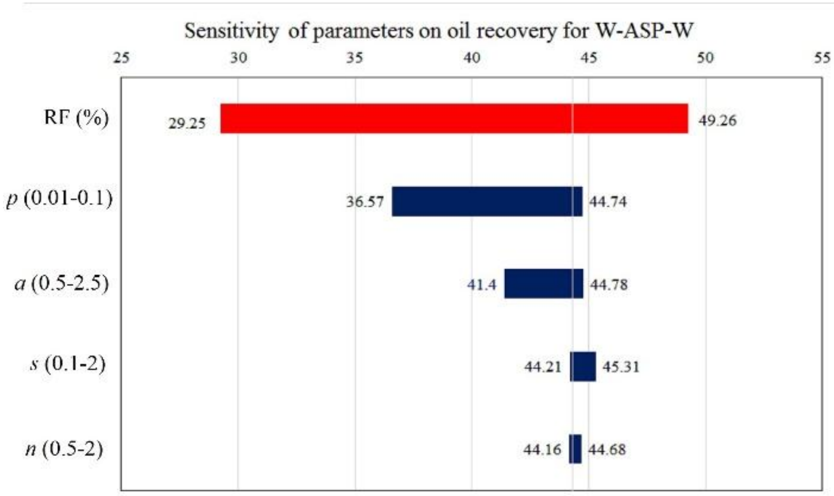


(**b2**)

Figure 7: Correlations between the design variables and the response surfaces: (a1) a-s vs. RF for W-ASP-W, (a2) s-p vs. RF for W-ASP-W, (a3) s-n vs. RF for W-ASP-W, (b1) a-p2 vs. RF for W-ASP-P-W, and b2) p2-w vs. RF for W-ASP-P-W.



(**a**)



(**b**)

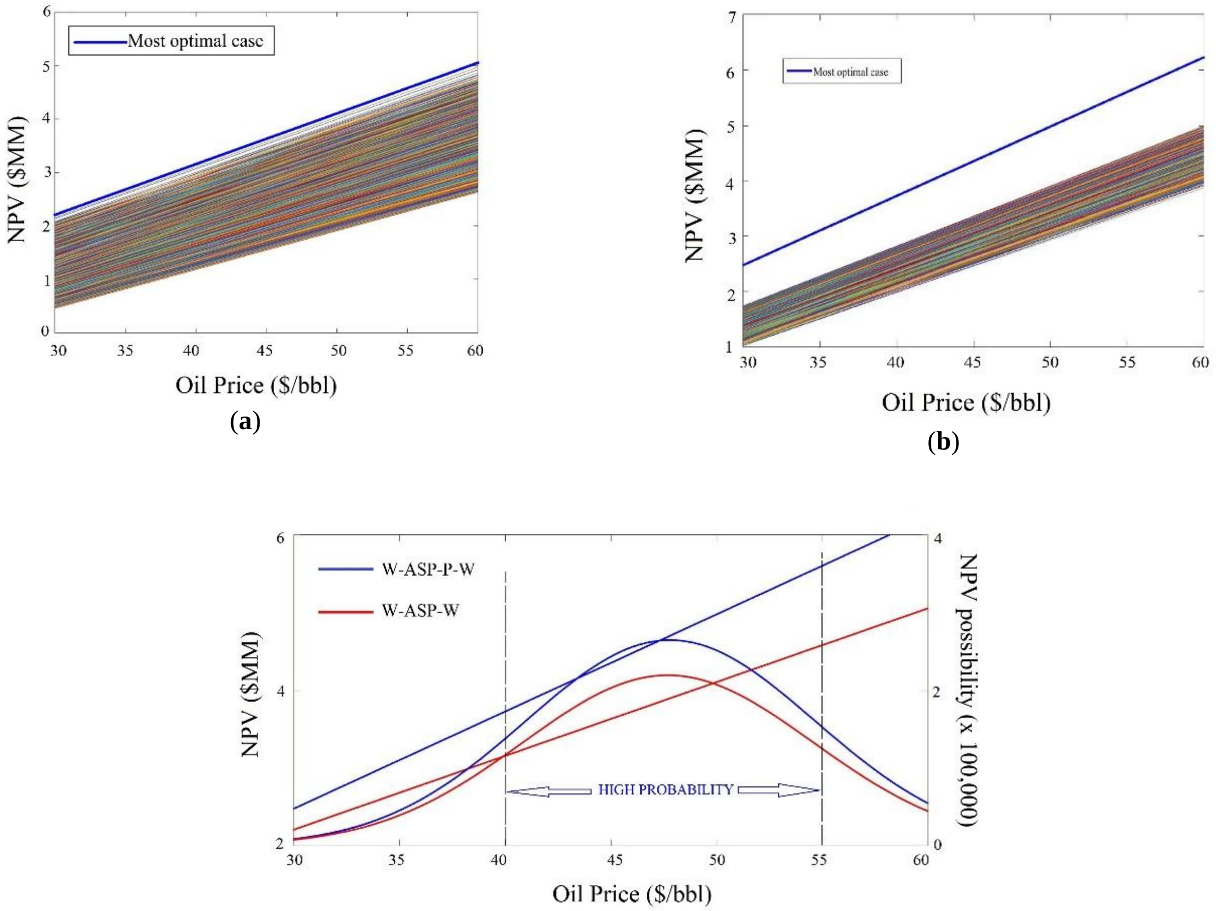
Figure 8: Sensitivity of the recovery factor to design parameters: (a) W-ASP-P-W and (b) W-ASP-W.

After determining the quadratic models for the computation of the recovery factors and total chemical expenses, the optimization processes can be carried out on the basis of these models with the aim of obtaining the highest NPV. Table 5 presents the optimal parameters of both flooding schemes. Except for the other parameters, the optimal values of the polymer concentrations are obviously at the limit constraints for both chemical injection sequences. This justifies the prior contribution of the polymer to either an enhancement in the oil recovery or the achievement of profit in comparison with other parameters.

According to the optimal results, the project can obtain a profit of 6.2 $MM at an oil price of 60 $/bbl, corresponding to a recovery factor of nearly 61%. However, this value might not fully reflect the feasibility of the project since the variations in the oil price are still in question, and the highest NPV of both schemes fluctuates by approximately 16%. The consideration of the variations in the oil price is mandatory for an uncertainty analysis; particularly, it can be a factor for the project decision. Figure 9 shows the NPVs according to changes in the design variables and the variations of oil price. From the figure, it is easy to recognize that if designed imprudently, the total benefit of the W-ASP-P-W scheme might decrease to be lower than that without the use of a second chemical slug. Figure 9 (c) shows a comparison of two optimal injection schemes in terms of the NPV and NPV possibility and evidently demonstrates the completely predominant application of the optimal design for the W-ASP-P-W scheme according to the proposed oil-price range. In addition, when considering the probability distribution of the oil price, the highly possible maximum NPV might fluctuate from 3.5 $MM to 5.5 $MM, corresponding to price from 40 $/bbl to 55 $/bbl for this flooding scheme, compared to the profit range of approximately 2.4 $MM to 3.4 $MM for water flooding, which absolutely affirms the potential utilization of chemicals in enhancing the heavy-oil recovery of the project.

Table 5: Optimal values of the design variables.

Optimization terms	W-ASP-W				W-ASP-P-W					
	a	*s*	*p*	*n*	*a*	*s*	p_1	n_1	p_2	n_2
Optimal values (wt%)	1.45	0.6	0.1	2	0.5	2	0.01	2	0.1	1.46
Optimized NPV (at 60$/bbl)	5.0556 $MM				6.2282 $MM					
Base-case NPV (at 60$/bbl)	4.4250 $MM				4.5476 $MM					
RF at optimized NPV	46.32%				60.99%					



(**a**) (**b**) (**c**)

Figure 9: Consideration of oil price variation on NPV: (a) NPV for various cases of W-ASP-W schemes, (b) NPV for various cases of W-ASP-P-W schemes, and (c) NPV and NPV possibility of the two optimal injection schemes.

The inclusion of the variations in oil price definitely assists in obtaining a more subjective evaluation of the economic situations of individual chemical flooding sequences and the selection of the most relevant strategy for deployment in order to gain the greatest benefit. Moreover, the probability distribution introduced in this work can be developed for the financial analysis of a practical project, particularly when the oil price becomes highly uncertain and is a key part of a project decision.

CONCLUSIONS

Technically, the paper has presented the sweep efficiency of an ASP injection process in a thin heterogeneous reservoir to recover crude heavy-oil through the saturation profiles of three sections. The simulated results indicated the ununiform swept patterns among layers, and even though the formation is too thin to consider other thermal methods, oil was still extracted dominantly in the layer where the wells were located. This substantially expresses the unfavourability of heterogeneity on utilizing a chemical flooding for enhancing heavy oil production, even though the chemical agents are properly designed.

In the pre-evaluation stage, two base-case flooding sequences are selected according to the variations in the oil price as a consequence of obtaining the highest NPV corresponding to each oil price. Following this, a single ASP flooding sequence and the other ASP scheme followed by a buffering polymer solution result in higher profits than the repetition of an ASP slug with a water slug in between injection sequences.

In the post-assessment stage, quadratic response models have been successfully applied to obtain the mathematical correlations between the chemical concentrations, oil recovery factor, and total chemical expenses for NPV optimization processes. The models also provide understanding of the sensitivities of the oil recovery factor to the design variables. Following this, the polymer concentration should be prudentially considered since this parameter for the second solution slug has a greater influence than that for the first chemical slug.

The ultimate feasibility results of this study might not represent most of EOR processes, nevertheless since the use of chemicals is usually disputed to a heavy oil reservoir, the aforementioned findings and methodology support to fulfill the understanding on the efficacy of such an EOR method in a heavy oil field.

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The authors declare no conflict of interest.

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