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Selection of Proper EOR Method for Efficient Matrix Recovery in Naturally Fractured Reservoirs

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Abstract

As most of the oil is stored in matrix due to its higher storage capacity than fracture network of naturally fractured reservoirs (NFR), reservoir development plans will aim at maximizing the matrix oil recovery. An enhanced oil recovery (EOR) application principally targets (a) to minimize the residual oil in matrix depleting the matrix as effective as possible and/or (b) to accelerate the recovery rate for rapid production of oil cost efficiently. For reservoirs with high recovery factor, minimizing matrix residual oil saturation is a critical issue to extend the life of the reservoir. For reservoirs with low recovery factor, accelerating the production rate is more vital. For each of these reservoir types, different EOR methods should be considered and implemented accordingly. This paper addresses and discusses these two issues and identifies selection criteria for different EOR methods in NFR, namely chemical (surfactant and polymer) and hot water injection.

The focus is specifically on matrix type (permeability and wettability), oil and water viscosities, matrix boundary conditions, transfer type (co- or counter-current imbibition), and IFT. For the different values of these properties, the most proper injection fluid type to be used as an EOR fluid is identified to obtain an effective matrix recovery. Co-current and counter-current capillary imbibition experiments at static conditions are conducted to show how effective and how useful these applications are for different rock and fluid types and matrix boundary conditions. For experimentation, strongly water wet Berea Sandstones and oil-wet carbonates (cores from an oil formation) are used. Light crude oil, kerosene and engine oil are selected as the oleic phase.

Proper project implementation (adjustment of injection rate and/or concentrations) and selection of the injection fluid for a cost efficient management are also discussed for different conditions outlined above. Finally, the selection criteria of EOR methods based on the rock and fluid properties are defined. This will provide an insight into an effective management of NFRs and reservoir depletion strategies, if the matrix oil recovery is the main target.

Introduction

If matrix is water wet and enough amount of water is supplied in fracture network, capillary imbibition governs the recovery from naturally fractured reservoirs. Rock properties such as matrix permeability[1-4], size and shape[1,3,5-7], wettability[8-12], heterogeneity[2,8,13], and boundary conditions[3,5-7,14,15] control the process. The properties of imbibing water[16], viscosities of the phases[5,6,11,12,17-19] and interfacial tension (IFT)[3,15,20-23] also play a role on the capillary imbibition recovery rate. These properties determine the recovery rate and the ultimate recovery.

Unfavorable conditions such as heavy-oil, oil wet matrix, matrix boundary conditions limiting the dynamics of oil displacement, large matrix sizes, low matrix permeability, and high IFT require additional effort to enhance the oil recovery. In fact, water injection might yield limited recovery when the unfavorable conditions exist and different methods should be applied to overcome these difficulties.

Heat injection resulting in the reduction of oil viscosity and IFT[11,12,24,25], injection of surfactant[15,20-23,26] and polymer solutions[18] have been tested in laboratory conditions previously for this purpose.

Field applications of oil recovery through capillary imbibition is as old as 50 years. First paper published in this area was by Brownscombe and Dyes discussing the possibility of water imbibition for the Spraberry field[27]. Much later, response of North Sea chalk to water injection was reported for different fields[28-31]. In all these applications, water has been the injectant without any additives. Although the reservoir rock is carbonaceous origin, notable recovery was observed in these applications. The idea of injecting surfactant solution to improve imbibition recovery was proposed later for fractured North Sea chalk[32-35]. These studies were all limited with laboratory scale experimentation and no field application of surfactant supported water injection has been reported for North Sea chalk reservoir yet.

A group of naturally fractured reservoirs exists in Western US, which are good candidates for waterflooding to recover matrix oil by capillary imbibition. The matrix element is mainly composed of carbonate rocks in these fields. Capillary imbibition performances of the rocks from these fields were identified at laboratory scale experimentation[27,36-39].

Methods other than waterflooding were also tested for naturally fractured reservoirs in Western US. Injection of carbonated water[40-41] and surfactant solutions[42-44] are the most common examples. All these studies are limited with laboratory scale tests. Only field case reported is the injection of polymer solution to maximize the recovery in Powder River Basin in Wyoming[45].

Other studies as to the effect of surfactant on the capillary imbibition recovery performance basically aimed at identification of the mechanisms involved and increase in the recovery when surfactant (or other IFT reduction chemicals) are added to water[3,12,15,20-23].

Beside the Western US and North Sea reservoirs, a few applications of improving capillary imbibition recovery were reported. Lacq Superior is an example of field scale steam injection to enhance capillary imbibition recovery[46]. There exist quite a few candidates of naturally fractured reservoirs for EOR applications in Middle East. Carbonaceous origin of the rocks in these fields requires methods other than waterflooding but not many attempts have been reported yet for the reservoirs in this region. A large size field development application of steam injection is underway in Qarn Alam Field in Oman[47,48]. The capillary imbibition and thermal expansion of oil are the mechanisms expected to contribute to the recovery in this intensely fractured carbonate field, yet no field performance is reported.

In this study, different EOR methods, such as chemical and hot water injection, to recover matrix oil by capillary imbibition were tested for different matrix and oil properties. Then, the most convenient method in terms of the recovery rate and ultimate recovery was identified for different matrix boundary conditions, oil viscosity and matrix wettability. At the end, a discussion on the cost efficiency of these processes was provided.

Experimental Study

Experiments were conducted on two types of rocks: (1) Berea Sandstone and (2) dolomitic limestone cores. Different types of oils and aqueous phases were used for different matrix boundary conditions. The sample preparation and experimental procedure are explained below.

Rock and Fluid Properties. Berea Sandstone samples were cut 3.80 cm and 2.54 cm in diameter and 10 cm in length from the same block. The average values of the porosity and permeability of the samples are 20% and 500 mD, respectively. Each sample was used only once to avoid any possible alteration in the wettability of rock due to cleaning procedure and chemicals. Carbonate samples were plugged out as 2.54 cm in diameter and 5 cm in length from a dolomitic limestone reservoir core. The porosity and permeability values vary between 11 and 25 % and 1 to 276 mD, respectively.

Three types of oil were used: (a) kerosene, (b) light crude oil and (c) engine oil. The properties of the fluids are given in **Table 1**. Surfactant solution was prepared by mixing a non-ionic surfactant (t-octylphenoxypoly ethoxyethanol) 1 and 2.5 volume % with 3 % NaCl brine. To prepare polymer solutions, two different concentrations of polyacrylamide polymer (0.1 and 0.2 wt %) yielding two different apparent viscosities were used. Hot water was also used as an aqueous phase in some of the experiments. The brine was heated up to the temperature desired in an oven and the sample was placed into the imbibition tube filled with preheated brine. Two temperatures were applied: 40 and 80 ^{o}C.

Some of the Berea Sandstone samples were coated using epoxy, depending on the boundary conditions desired and dried one day at room temperature. Then, the coated samples were fully saturated with the oil under vacuum for 24 hours. All the samples were exposed to oil saturation only 24 hours to ensure that no wettability alteration takes place by aging.

Carbonate samples were not coated and after cleaning procedure and porosity-permeability measurements, they were saturated with light crude oil (properties given in Table 1) and exposed to capillary imbibition by placing them in imbibition tubes.

Procedure. Two types of experiments were conducted under static conditions: (a) co-current and (b) counter-current capillary imbibition. The type of transfer is determined by the boundary conditions created by the coating procedure. Different boundary conditions obtained by coating the sample are shown in **Fig. 1-a** and **b**. After coating and saturating the samples with 100 % oil (no initial water in the system), they were immersed into an imbibition cell filled with the aqueous phase (brine, polymer solution, surfactant solution or preheated hot water) and exposed to capillary imbibition. The recovery was monitored against time.

For counter-current experiments, the cylindrical core sample, 3.80 cm in diameter and 10 cm. in length, was cut vertically and the halves of the samples were used. In all cases, the outer side (curved part), top and bottom parts were coated (Fig. 1-a). Thus, the counter-current imbibition takes place through the flat surface of the semi-cylindrical sample (COU-C1). The other different boundary conditions were created by coating the 50 % (COU-C2) and 90 % (COU-C3) of the flat surface with the epoxy.

Co-current experiments were conducted using cylindrical samples. CO-C1 in Fig. 1-b represents non-coated case. CO-C2 and CO-C3 are 50 % and 90 % coated cases, respectively. In all the experiments, the samples were positioned as seen in Fig. 1 and the coated part was kept upward in the imbibition cell. Thus, the aqueous phase imbibes from the bottom of the coated sample and rises up through the sample displacing the oil by capillary forces against the gravity. The extreme boundary conditions were applied to be able to fully distinguish the effect boundary conditions on the recovery. In fact, the boundary condition is one of the main causes of high residual oil saturation in the matrix that entails additional EOR applications[15]. In some of the co-current experiments 2.54 cm diameter samples were used.

For carbonate core sample experiments, only CO-C1 type boundary condition was applied. It should be emphasized that all the samples were saturated with 100% oil phase (without S_{wi}) also in this group of experiments.

Analysis of the results

The experimental results were illustrated as oil recovery (as % OOIP) against time. In the analyses, ultimate recovery and recovery rate were used as performance indicators.

Co-Current Imbibition in Sandstone. The results of the experiments on Berea Sandstones will be evaluated for three types of aqueous phases and three oil types.

Surfactant Solution as an Aqueous Phase. The imbibition recovery curves for kerosene-brine and kerosene-surfactant solution pairs are given in **Fig. 2**. In all cases, ultimate recovery of surfactant solution imbibition is slightly higher than brine imbibition. The recovery rate of high IFT case is somewhat higher for boundary condition of CO-C1. This is consistent with the previous observations[3,11,15,20-22]. However, the recovery rate is strictly controlled by the boundary condition. For the extreme boundary condition (CO-C3), the recovery rate is much lower for low IFT case. Similar recovery profiles were obtained for the crude oil samples as well (**Fig. 3**). For boundary conditions of CO-C1 and 2 of the crude oil experiments, the recovery rate and ultimate recovery for low and high IFT cases are similar. The small differences can be attributed to possible local differences in permeability of the sandstone block even though the cores were plugged out from the same block.

The reason of slower recovery in Figs. 2-c and 3-c can be explained through the following dimensionless group proposed by Mattax and Kyte[1].

$$t_d = t\,\frac{\sigma}{\mu_w L^2}\sqrt{\frac{k}{\phi}} \tag{1}$$

According to this correlation, increasing IFT yields a faster recovery as observed through Figs. 2-a and b. For crude oil case (Figs. 3-a and b) the difference is quite insignificant. This can be attributed to relatively small change in the IFT with the addition of surfactant for crude oil case (25 to 11 dyne/cm) compared to the kerosene case (from 40 to 11 dyne/cm). As the IFT is lowered, the gravity becomes also effective on the recovery. The change on the recovery curves with decreasing IFT can be explained through inverse Bond Number, N_B^{-1} which is the ratio of capillary forces to the gravity forces given as follows:

$$N_B^{-1} = c\,\frac{\sigma\sqrt{\frac{\phi}{k}}}{\Delta\rho g H} \tag{2}$$

As the IFT is lowered, the capillary forces dwindle and the gravity forces begin to dominate. For unfavorable boundary condition (CO-C3), however, the travel of the water inside the core (upwardly against the gravity) is achieved only by capillary forces. Therefore, significant reduction in the recovery rate can be observed with the reduced IFT in Figs. 2-c and 3-c.

As a third case, heavy-oil (engine oil) imbibition was considered. Even though a slightly lower ultimate recovery was obtained, the recovery profile is the same as the light oil recovery case when the boundary condition of CO-C1 is applied (**Fig. 4-a**). The imbibition rate of high IFT case (brine) is higher than that of low IFT case (1 vol % surfactant). In contrast to the light oil examples, the ultimate recovery by capillary imbibition of brine is significantly lower for boundary condition CO-C2 (10 %) than that of the boundary condition CO-C1 (41 %) (**Fig. 4-b**). The ultimate recovery, however, was doubled when the surfactant was added to the aqueous phase (see Figs. 2-b and 3-b). This was not observed for two light oil cases. This is a considerable addition to the recovery and it is expected that most of this additional recovery come from the uncoated part of the sample (see boundary condition CO-C2 in Fig. 1). It should also be noted that an increase in surfactant concentration did not contribute to the recovery as the IFT did not change after increasing the surfactant concentration 2.5 fold (see Table 1). Thus, there exists a critical surfactant concentration optimizing the recovery.

Polymer Solution as an Aqueous Phase. Polyacrylamide polymer was added to brine at different concentrations and used as the aqueous phase. Only heavy (engine) oil saturated samples were exposed to polymer solution imbibition. The oil recovery against time was plotted for two polymer solutions and brine in Fig. 4-c. It was observed that both recovery rate and ultimate recovery increased with the addition of polymer solution. Two effects of polymer solution in the recovery are expected. The first one is the increase in the viscosity of displacing (aqueous) phase and the second one is the decrease in the IFT (Table 1). When the cases shown in Fig. 4-c are compared with the ones in Fig. 4-a, one can observe that surfactant addition yields a slower recovery rate. This is in accordance with Eq. 1. The recovery rate, however, is higher for polymer case as an indication of the positive impact of an increase in aqueous phase viscosity. The increase in the ultimate recovery after chemical addition is almost the same for surfactant and polymer cases.

When the boundary condition of CO-C2 is applied, the increase in the recovery rate and ultimate recovery is more significant (Fig. 4-d). When the surfactant (Fig. 4-b) and polymer (Fig. 4-d) cases are compared, one can easily see that the contribution to the recovery rate and ultimate recovery by polymer solution is more pronounced.

Hot Water as an Aqueous Phase. Hot water was used as an aqueous phase either throughout the experiment or after reaching the ultimate recovery with brine only. For co-current experiments, only engine oil saturated samples were exposed to hot water imbibition. Fig. 4-b demonstrates the effect of hot water imbibition performance for boundary condition of CO-C2. The imbibition using brine yielded only 11 % of OIIP recovery whereas the addition of surfactant to brine almost doubled the ultimate recovery. After completing the brine imbibition, the same sample was exposed to preheated hot water. Additional 12 % recovery was obtained in a short period of time. The thermal expansion is expected to yield 6-7 % recovery within this temperature range[11,19,24]. The rest of the recovery is due to capillary imbibition accelerated by the reduction in viscosity and most likely this amount is recovered from the uncoated part of the sample. In fact, if one compares the two cases illustrated in Figs. 4-a and b, 50 % recovery is expected if the boundary condition CO-C1 is applied. The ultimate recovery obtained by brine+hot water was half of this amount (25%) for the boundary condition CO-C2. That implies that the only uncoated part of the sample was thoroughly depleted even with additional temperature effect in case of heavy-oil.

Figs. 4-c and d also compare the recoveries obtained with polymer solution and brine succeeded by hot water. In both cases, some additional recovery was obtained with increased temperature of water. For boundary condition of CO-C1 (Fig. 4-c) the total recovery with brine+hot water exceeded the ultimate recovery of oil obtained with polymer solution. For boundary condition of CO-C2 (Fig. 4-d), the recovery is almost the same for both polymer and brine+hot water cases. Finally, the recovery profiles of continuous hot water experiments were compared (Fig. 4-e). The brine temperature of 40 ^oC did not contribute to the recovery rate and ultimate recovery but the recovery rate and ultimate recovery substantially increased when the brine temperature of 80 ^oC was applied. The flat part of this curve (brine at 80 ^oC) is due to boundary condition type (CO-C2). After recovering the oil in uncoated part of the matrix, there was a period of no production until the oil in the upper part of the matrix (coated part) began to drain. Although a much faster production is observed at the early stages of the production due to the thermal expansion of oil (as consistent with Ref. 11 and 24) the ultimate recovery is almost the same and the recovery time is lower than the polymer (Fig. 4-d) and surfactant cases (Fig. 4-b).

In summary, for unfavorable boundary condition, starting with brine and continuing with hot water is not an effective project implementation even though the same ultimate recovery is reached at the end. Starting at higher temperatures (80^{o}C) and continuing with it yields more effective recovery. This observation agrees with the other laboratory scale experimental studies[11,25,46].

Co-Current Imbibition in Carbonates. Capillary imbibition experiments were repeated using the same type of aqueous solutions but different rock type. Dolomitic limestone plugs taken out from an oil formation core sample were cleaned and saturated with 100% crude oil whose properties shown in Table 1. Then, the samples were exposed to capillary imbibition using four types of aqueous phases at different concentrations, namely, brine, surfactant and polymer solutions, and hot water. The slow recovery rate and small amount of ultimate recovery of oil (5 % only) by brine imbibition (solid dashed line in **Fig. 5**) indicates the wettability of the sample as being strongly oil wet. Improving the capillary imbibition in this type of reservoirs is a great challenge[25,49]. Although other matrix-fracture transfer mechanisms such as gravity drainage or pressure depletion can be effective on the recovery, these processes are rather slow[19,24,25]. Using an additional support, capillary imbibition can be enhanced by reduction in IFT, changing wettability or other thermal effects. Therefore, capillary imbibition experiments were conducted using additional chemical and heat effect. The recovery curves obtained are given in Fig. 5 for comparison with the brine case. Note that the permeability changes in each plug due to heterogeneous character of the formation even though the plugs were taken out as very close to each other and avoiding the fractured parts of the core. Because of this fact, the plugs for the experiments with the same type of fluids were selected as having close permeabilities. For example, the plugs exposed to high temperature capillary imbibition have 1 and 4 mD permeability values. Plugs used for the surfactant experiments with two different concentrations have 19 and 24 mD permeability values. Samples used for polymer experiments have also close permeability values (128 and 155 mD). The highest permeability sample was used for the brine imbibition experiment. This would allow us to be able to compare the results more meaningfully.

Despite of the highest permeability, the slowest recovery was obtained for the brine case as mentioned before. Highest recovery rates were obtained for higher temperature experiments (2 solid lines) even though they have the lowest permeability values. Surfactant solutions yielded faster recovery than polymer solutions and brine. But the highest ultimate recoveries were obtained using polymer solutions. Ultimate recoveries for the surfactant and high temperature experiments are the same. Experiment at 40^{o}C yielded slightly lower recovery than others but by a 40^{o}C increase at temperature, the same amount of oil recovery was achieved.

In summary, additional material (chemical and heat) resulted in doubling the ultimate recovery (from 5 to 10 %) and much faster recovery rate. The most favorable method is obviously hot water injection but the polymer solutions yielded slightly higher recovery most likely due to combined effects of increase in water viscosity and reduction in IFT (see Table 1).

Counter-Current Imbibition in Sandstone. It is expected that the imbibition recovery performance is significantly affected by the transfer type (or direction) determined by the matrix boundary conditions[3,6,15,16,50]. Therefore, some of the experiments were carried out also for counter-current imbibition. Three boundary conditions given in Fig. 1 were applied for the samples saturated with kerosene and crude oil. The results are given in **Fig. 6** for the kerosene saturated samples. The recovery profiles are reminiscent of the ones obtained for the co-current case (Fig. 2). In all experiments surfactant addition yielded a slight increase in the ultimate recovery but the recovery rate is higher for the higher IFT case (brine imbibition). The difference in the recovery rates for high and low IFT curves are more distinguishable for unfavorable boundary conditions. Hence, for unfavorable boundary conditions, the surfactant imbibition is not recommendable.

In recovering light crude oil, expected recovery curves, i.e., higher recovery rate for brine imbibition, were obtained as shown in **Fig. 7-a**. The ultimate recovery is slightly higher when the surfactant is added. For boundary condition of CO-C2, however, low IFT case yielded much faster recovery (Fig. 7-b) as opposed to the co-current case of the same type of boundary condition (Fig. 3-b). When the polymer was added for the same boundary condition, no positive effect of it was observed. In fact, substantial reduction in the recovery rate and ultimate recovery was obtained. Beyond that, increasing polymer concentration yielded slower process. This can be attributed to the increase in the aqueous phase viscosity that causes a slower upward movement (against the gravity) to recover oil in coated part of the matrix (see Fig. 1 boundary condition COU-C2).

Finally, the tests were repeated using hot water at two different temperatures (40 and 80^{o}C). Increasing temperature of the aqueous phase substantially improved the recovery rate but no significant change in the ultimate recovery was obtained (Fig. 7-d). In summary, comparing four cases illustrated in Fig. 7, addition of surfactant and heat accelerated the recovery rate but no significant increase in the ultimate recovery was obtained. Polymer injection did not help to the recovery rate and ultimate recovery when unfavorable boundary conditions exist for counter-current flow.

Selection Criteria for proper EOR fluid

The selection criteria of the proper method (or EOR fluid) will be summarized and discussed in terms of (a) recovery rate and (b) ultimate recovery for different oil types and matrix properties, namely wettability and boundary conditions.

Sandstones.

1. For the recovery of light oils (kerosene and crude oil) by capillary imbibition under favorable boundary conditions (CO-C1 and CO-C2), addition of surfactant did not contribute to the rate of recovery. Ultimate recovery increased slightly by surfactant addition. However, in case of unfavorable boundary condition (CO-C3), the negative effect of low IFT on the recovery rate was obvious. The recovery rate was reduced significantly but the ultimate recovery did not change. Therefore, low IFT is not suggested for any boundary condition and slight increase in the ultimate recovery would not support the idea of injecting expensive chemicals continuously. This obviously would not turn out to be an economic application. The same conclusions are applicable for the counter-current matrix-fracture transfer as well.
2. For heavy-oil case, surfactant addition yielded a significant increase in the recovery rate and ultimate recovery for unfavorable boundary condition (CO-C2). For favorable boundary condition (CO-C1) brine recovery rate was slightly higher but ultimate recovery was slightly lower. The slight changes in these performance indicators suggest that surfactant addition would not be desirable if the economics of the process is a concern for the favorable boundary condition.
3. For heavy-oil recovery under favorable (CO-C1) and unfavorable (CO-C2) boundary conditions, polymer addition to brine yielded much faster recovery and higher ultimate recovery than surfactant case. For unfavorable boundary condition, the ultimate recovery obtained by the polymer solution is higher than hot water injection but high temperature water injection (80^{o}C) resulted in much faster recovery. Thus, the selection of proper method depends on the cost of the project as well as the managerial concerns. In heavy oil case, the major concern, from the long-term reservoir management point of view, is expected to be increasing the production rate rather than increasing the ultimate recovery. In summary, hot water is more advisable if it reflects an economic application for long term plans in particular.

   Also, for unfavorable boundary conditions, starting with brine and continuing with hot water is not an effective project implementation due to very slow recovery rate even though the same ultimate recovery is achieved at the end. For this type of boundary conditions, polymer solution is preferable to the surfactant solution.
4. In light crude oil recovery, polymer is not recommendable for unfavorable boundary conditions (COU-C2) of counter-current flow due to much slower recovery rate and lower ultimate recovery. Hot water injection yields much faster recovery. If the concern is to increase the ultimate recovery, no additional method is recommended. If the faster production rate is desired, hot water is recommendable.

Carbonates. For oil-wet carbonate matrix, the improvement of capillary imbibition is more crucial issue. Even for the most favorable boundary condition (CO-C1), the recovery was as low as 5 % and an additional "accelerator" was required. Technically, the most recommendable methods are hot water, surfactant and polymer, from the best to the worst, if the recovery rate is concerned. The methods yielded a doubled recovery (from 5 to 10 %) and this can be considered as an achievement for a challenging naturally fractured reservoir. Even though the polymer rate is somewhat lower, it yields the highest recovery due to combined effect of lowered IFT and increased displacing phase viscosity. Considering the fact that some part of the recovery is due to thermal expansion of oil in case of hot water injection, combination of hot water and chemical injection is technically recommendable for a successful management of the reservoir. But the economics of the process should be evaluated.

Two issues were not addressed in this paper. They are adsorption of chemicals and wettability change. For recovery performance analysis, the effect of wettability change is critical. Although the temperature range applied through the experiments is not expected to be influential on the wettability[51], surfactants are expected to affect the wettability[52]. The clarification of the wettability change effect on the recovery and chemical adsorption are considered to be the subject of a further study.

The selection of proper EOR method was discussed above from a technical point of view. For an effective field management, these observations can be helpful for decision making. If the purpose is to deplete the matrix oil effectively (or thoroughly), the target should be the ultimate recovery. Big size fields with high recovery rate are an example for this situation. If, on the other hand, the purpose is to increase the production rate, one should focus on the increase in recovery rate instead of ultimate recovery. Fields with low recovery factor (heavy-oil, carbonates) can be good candidates for this effort. These managerial concerns will determine the type of the proper EOR fluid. Obviously, the next issue will be the inclusion of the project cost to the analysis.

Efficiency of Matrix Oil Recovery

In above analysis, the recovery rate and ultimate recovery were used as the indicators of the recovery performance. This basically defines the effectiveness of the process. When the efficiency of the process is concerned, i.e., the amount of oil recovered per unit cost, the above analysis should be carried out considering the cost of the process. The experimentation methodology (static capillary imbibition) followed is not suitable for a cost analysis as the total amount of chemical or heat injected cannot be known. This is because of the static nature of the process but, in reality, there exists a continuous injection of the aqueous phase. Having known the injection rate and concentrations, one might be able to calculate the cost of the process as this would tell how much chemical needs to be injected to reach the ultimate recovery. Then, an economic analysis of the project can be implemented. For these reasons, a qualitative cost analysis will be provided here only. The dynamic laboratory scale experimentation will constitute the next phase of this research for the quantitative evaluation of cost (or efficiency of the process). Baviere et al.[53] conducted a detailed efficiency analysis for the chemical injection into homogeneous samples (non-fractured) incorporating the cost. They carried out displacement experiments considering the effects of adsorption and salinity of water and analyzed the different chemical injection scenarios to select the most cost efficient one. A similar approach would be useful for fractured systems as will be explained later.

Considering that the same injection rate is applied in all three cases of water, polymer, surfactant and hot water injection, a cost analysis can be applied. Although this may not reflect the real life situation, it would provide an insight into the cost of the project. For the time being, this is the only analysis that can be implemented with the existing experimental results. Based on the cost estimation exercise provided by Boberg[54] (page 97), the cost of 1 bbl of hot water generation at temperature of 80^{o}C (atmospheric pressure) is on the order of a dollar with the assumption of 25$/bbl oil price. The cost of 1 vol % surfactant and 0.1 wt % polymer solution are much higher. But hot water injection requires more CAPEX and OPEX compared to chemical injection. Nevertheless, if the water is injected in the form of hot water, the process cost is expected somewhat less assuming that the injection rate and period are the same. Note that, on the other hand, the fastest recovery was obtained by hot water injection and as a result of this, hot water injection would take shorter injection period than chemical ones. Thus, at first sight, thermal application, yielding the most favorable recovery profile technically, will also be beneficial when the efficiency (or the economics) of the process is also concerned.

Experiments performed under dynamic (fluid flow in fracture) conditions will be useful for the efficiency analysis as they provide the total amount of injectant necessary to reach the ultimate recovery. This type of experimentation has been used to identify the effectiveness or waterflooding recovery performance[55-61]. Apart from these studies focused only on the performance estimation, a few laboratory scale studies related to water injection optimization (or efficiency) in naturally fractured reservoirs were also reported recently[38,62,63]. In this regard, Babadagli and Ershaghi[64] proposed a dimensionless group containing matrix size and injection rate to indicate the capillary imbibition transfer rate for dynamic conditions based on the experimental data[4,61]. Later, Babadagli developed a laboratory[63] and a field scale[65] optimization scheme for waterflooding in naturally fractured reservoirs. Putra and Schechter[37] and Putra et al.[38] applied the laboratory scale optimization of waterflooding approach proposed by Babadagli[61] to field scale for the Spraberry Field. Later, Babadagli[12] included matrix size into the formulation indicating the capillary imbibition recovery proposed by Babadagli and Ershaghi[64].

Dynamic experiments will be the base for the numerical modeling study as they will provide necessary information and formulation towards the dynamics of the recovery, in particular, matrix fracture transfer. However, many other parameters are also needed for the accurate performance estimation and efficiency analysis through numerical modeling. Injection rate and concentrations are the only measurable and controllable parameters if a continuous flow in fractures involved in the process. Other parameters, which are not easily measurable or predictable, include matrix and fracture properties. Matrix size is a critical parameter affecting the imbibition performance (Eq. 1) in static conditions. An average matrix size can be estimated through core, well test and well log analysis[41,66-69]. The matrix size estimated through these tools would be useful in designing the injection strategy but more problematic issue is to characterize the matrix-fracture transfer type (co- or counter-current), which is controlled by matrix boundary conditions. This also requires a characterization of fracture network structure and connectivity.

As seen, field level performance estimation requires a significant reservoir characterization work. Data to be used in performance estimation studies are obtained through this characterization exercise. Yet, this data is based on the estimation of the parameters stochastically. Numerical simulation of dual porosity systems, the most common tool used for the field scale performance estimation, requires also the definition of matrix-fractures transfer[70,71]. Accurate estimation of the performance depends upon the correct definition of this transfer[71].

Many attempts have been made towards the identification and formulation of matrix fracture transfer of water in fractured porous media. When chemical and heat effects are included in the injection process, matrix-fracture transfer is expected to be different due to the different recovery mechanisms involved such as gravity effect, thermal expansion, molecular diffusion and other factors affecting the recovery indirectly such as adsorption and the behavior of non-Newtonian fluid in porous media. Simply, changing IFT and water viscosity may not be enough to assess the effectiveness (using Eq. 1) and efficiency of the process[26]. Therefore, the applicability of the Eq. 1 proposed by Mattax and Kyte[1] needs to be clarified for scaling purpose. Babadagli tested and proposed modified forms of this equation for hot water[12] and chemical solution[26] imbibition for static conditions. This is another issue to be clarified for the cost efficiency analysis of thermal and chemical methods in NFRs. In summary, even the matrix size effect on the capillary imbibition recovery using chemicals and hot water at static conditions is not well understood and formulated.

Dynamic laboratory scale study will be helpful to describe the matrix-fracture transfer for the heat and chemical injection. Limited number of studies was published in this area (dynamic flow conditions) without any cost analysis for chemical[18] and heat injection[12,19,73-75]. Among them Babadagli[19,75] provided an optimization approach and later cost analysis[76] using single porosity simulator and experimental study based on the injection rate of steam. These studies did not use any matrix-fracture transfer function. The present study, conducted at static conditions, is hoped to shed a light on the description and formulation of matrix-fracture transfer when the heat and chemical effects are also involved. In fact, matrix-fracture transfer during chemical (surfactant and polymer) and heat injection first to be clarified before attempting to any efficiency study.

Conclusions

In this paper, an extensive analysis and comparison of capillary imbibition recovery performances with brine, surfactant and polymer solutions, and hot water were provided for different rock samples and matrix boundary conditions. Then, selection criteria were discussed based on the recovery rate and ultimate recovery.

In the recovery of light oil samples, chemical injection is not recommended due to slower production rate. However, slight increase in the ultimate recovery was observed for both surfactant and polymer solution imbibition. Hot water yielded much faster recovery but the same amount of ultimate recovery as the chemical solutions. For heavy oil imbibition recovery, however, polymer solution, as well as hot water, yielded faster and higher recovery than the imbibition of surfactant solution. The selection of these methods depends highly on the cost of the project and managerial concerns.

For oil wet carbonates, hot water yielded the fastest recovery. The recovery rates obtained with the polymer and surfactant solutions were faster than brine. In all cases ultimate recovery obtained with brine was doubled but the ultimate recovery obtained with the polymer solution is slightly higher than that of the other EOR fluids.

The cost analysis, or the efficiency of the process, requires dynamic experimentations (or numerical simulation work that requires a matrix-fracture transfer function) so that the total amount of EOR fluid injected to reach the ultimate recovery is known. This study is hoped to shed a light on developing a matrix-fracture transfer function for further dynamic modeling studies. Also required for the efficiency analysis is to obtain concentrations (for chemicals) and temperature of hot water that optimize the process both technically and economically.

Nomenclature

BC = Boundary condition.
c = Constant.
IFT = Interfacial tension
k = Matrix permeability.
L = Matrix size.
H = Matrix height.
t = Time.
t_d = Dimensionless time.
ϕ = Porosity.
μ_w = Water viscosity.
ρ = Density.
σ = Interfacial tension.

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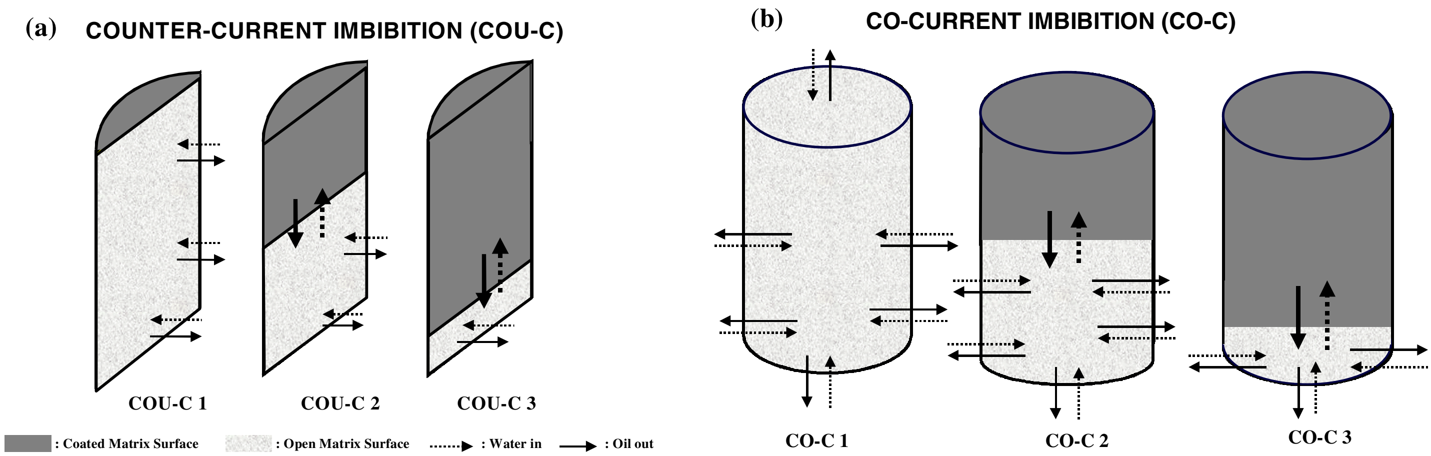

Fig. 1- Different matrix boundary conditions used in the experiments.

TABLE 1 – Fluid properties used in the experiments.

PHASE	FLUID TYPE	DENSITY (g/cc)	VISCOSITY (cP)	IFT (dyne/cm) (Kerosene)	IFT (dyne/cm) (Crude Oil)	IFT (dyne/cm) (Engine Oil)
WATER	Brine	1	1.1	40	25	71
	Surfactant 1 vol %	1	1.1	11	11	15
	Surfactant 2.5 vol %	1	1.1	-	-	14
	Polymer (0.1 wt %)	1	18	-	17	23
	Polymer (0.2 wt %)	1	87	-	22	24
OIL	Kerosene	0.79	1.7			
	Crude Oil	0.81	5.6			
	Engine Oil	0.89	633			

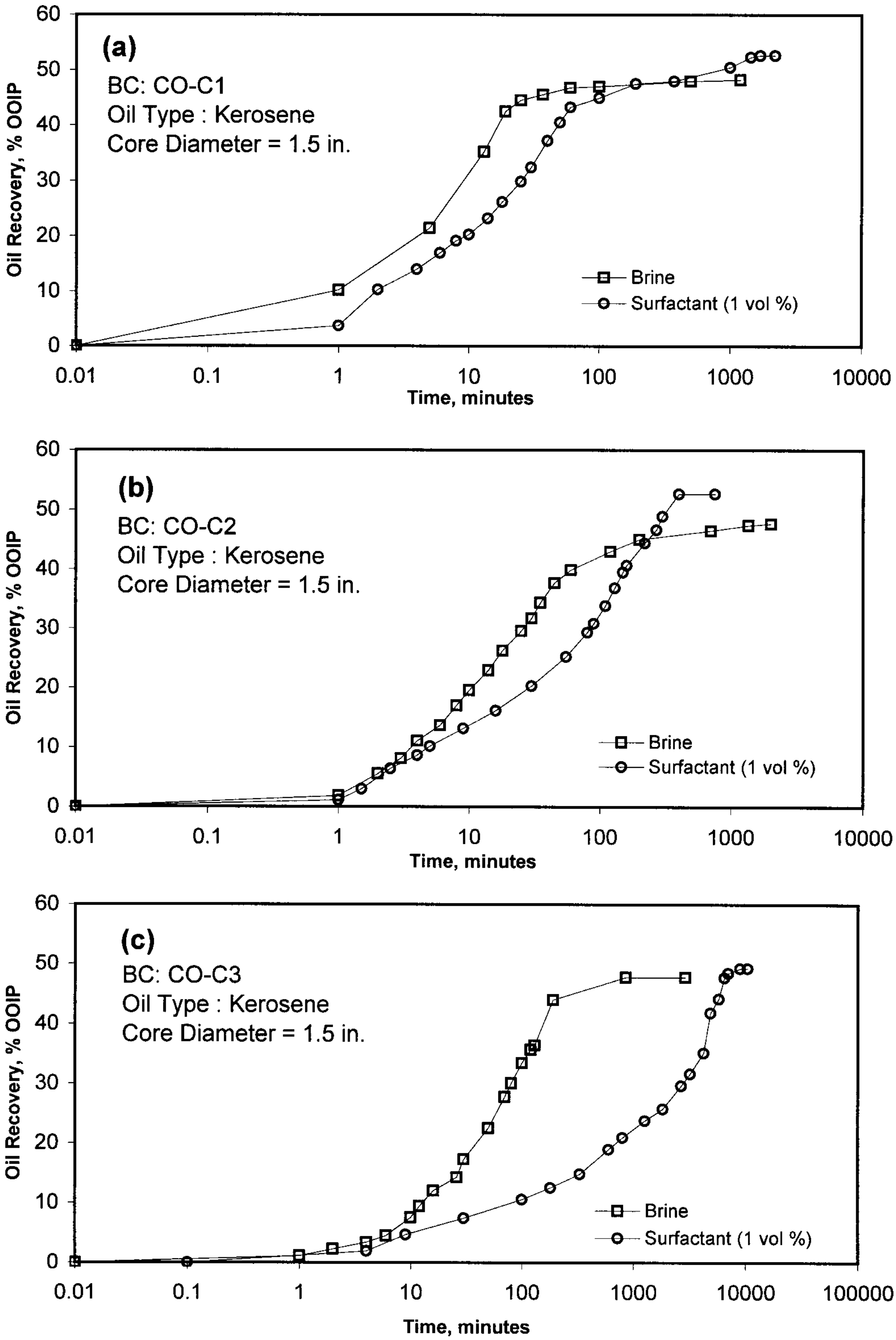

Fig. 2. Co-current imbibition recovery curves for different types of boundary conditions. (Rock Type: Berea Sandstone, Oil Type : Kerosene, BC: Boundary Condition given in Fig. 1)

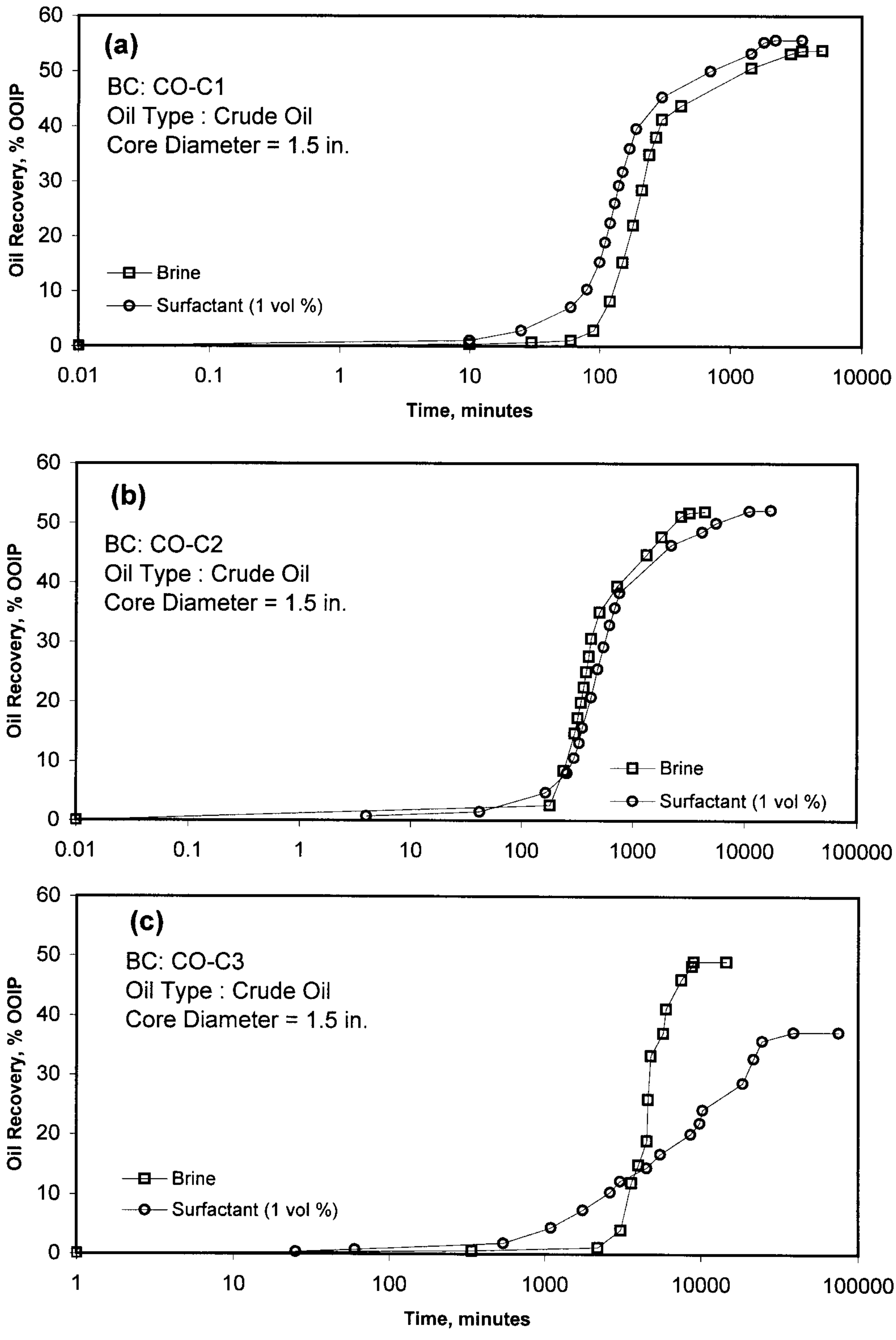

Fig. 3. Co-current imbibition recovery curves for different types of boundary conditions. (Rock Type: Berea Sandstone, Oil Type : Crude Oil, BC: Boundary Condition given in Fig. 1)

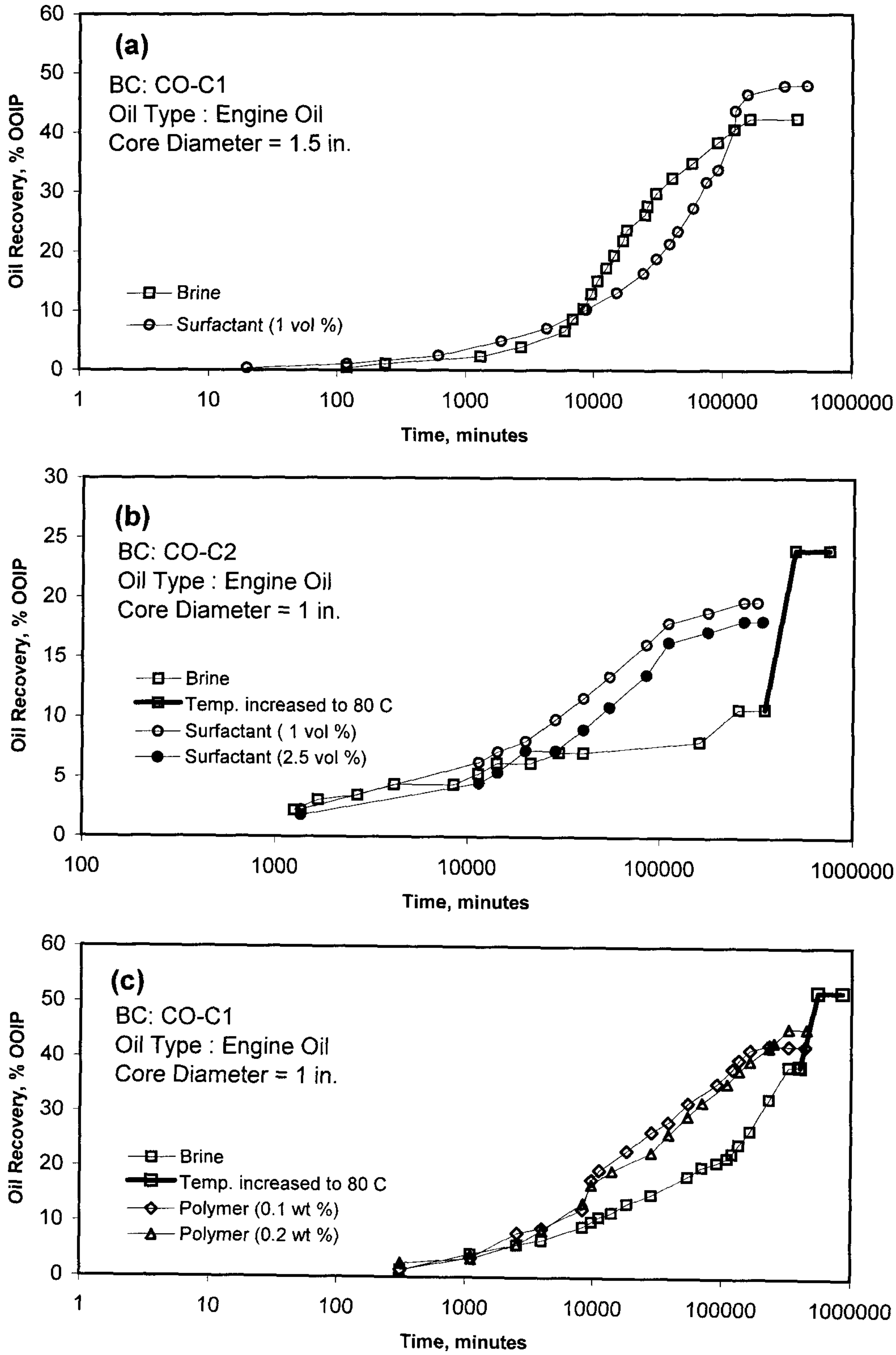

Fig. 4. Co-current imbibition recovery curves for different types of boundary conditions. (Rock Type: Berea Sandstone, Oil Type : Engine Oil, BC: Boundary Condition given in Fig. 1)

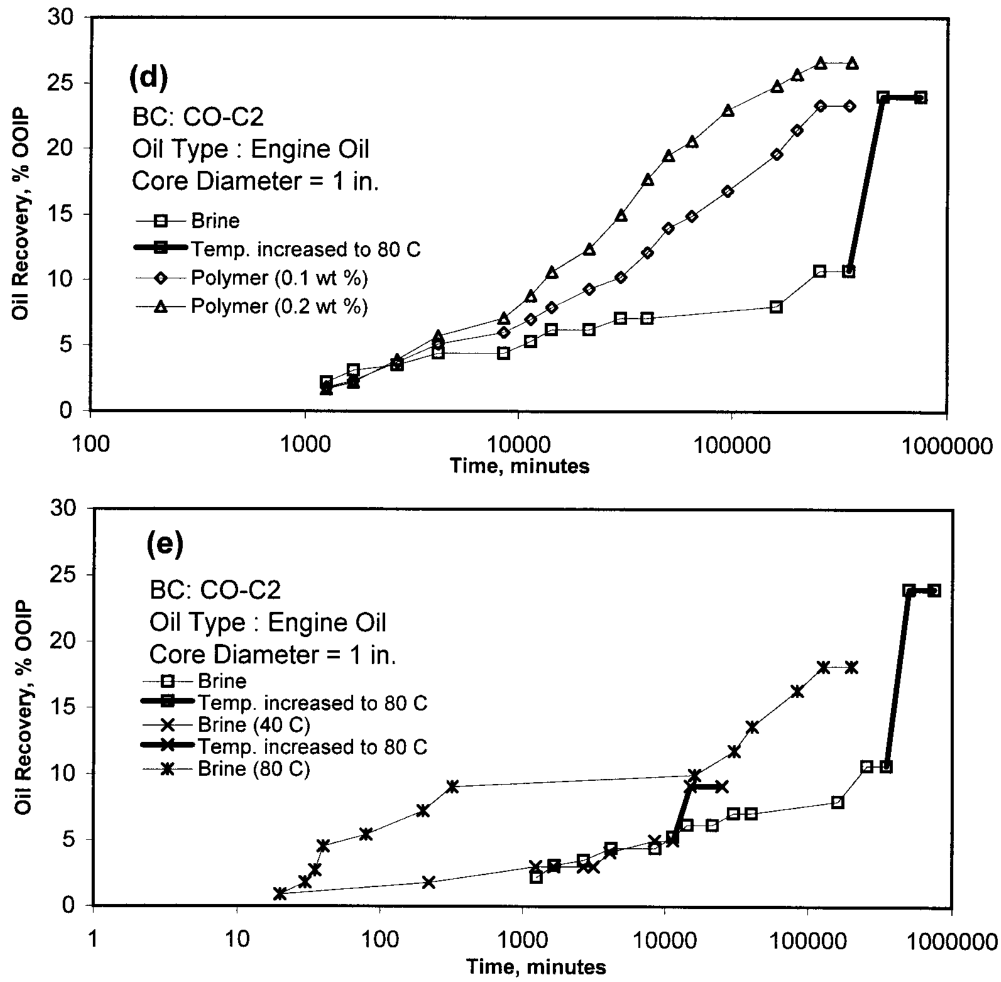

Fig. 4 (cont.). Co-current imbibition recovery curves for different types of boundary conditions. (Rock Type: Berea Sandstone, Oil Type : Engine Oil, BC: Boundary Condition given in Fig. 1)

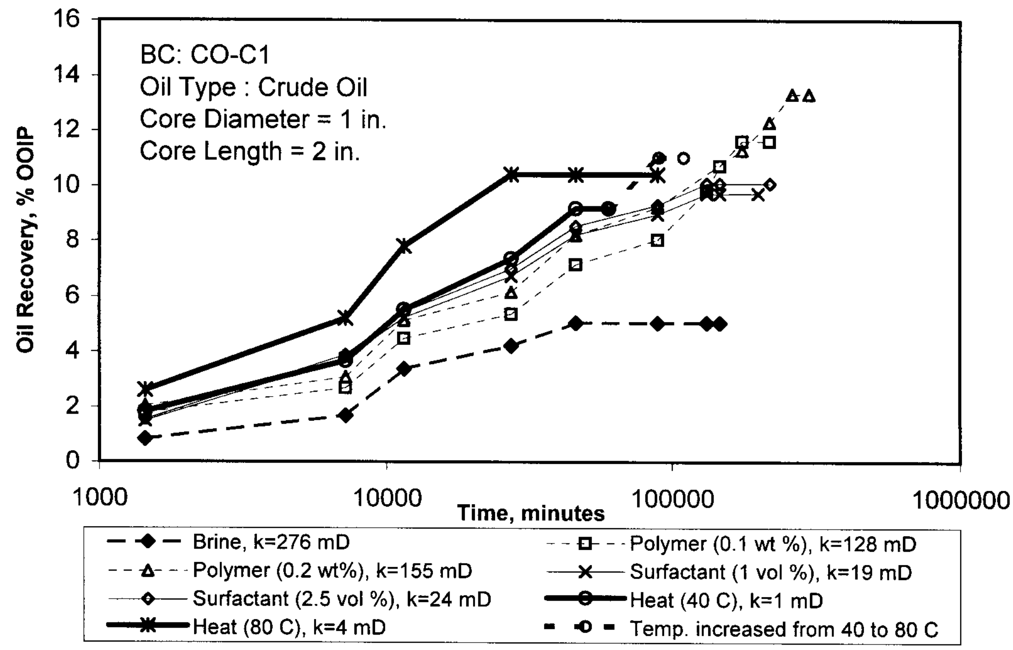

Fig. 5. Co-current imbibition recovery curves for different types of boundary conditions. (Rock Type: Dolomitic Carbonate Core, Oil Type : Crude Oil, BC: Boundary Condition given in Fig. 1)

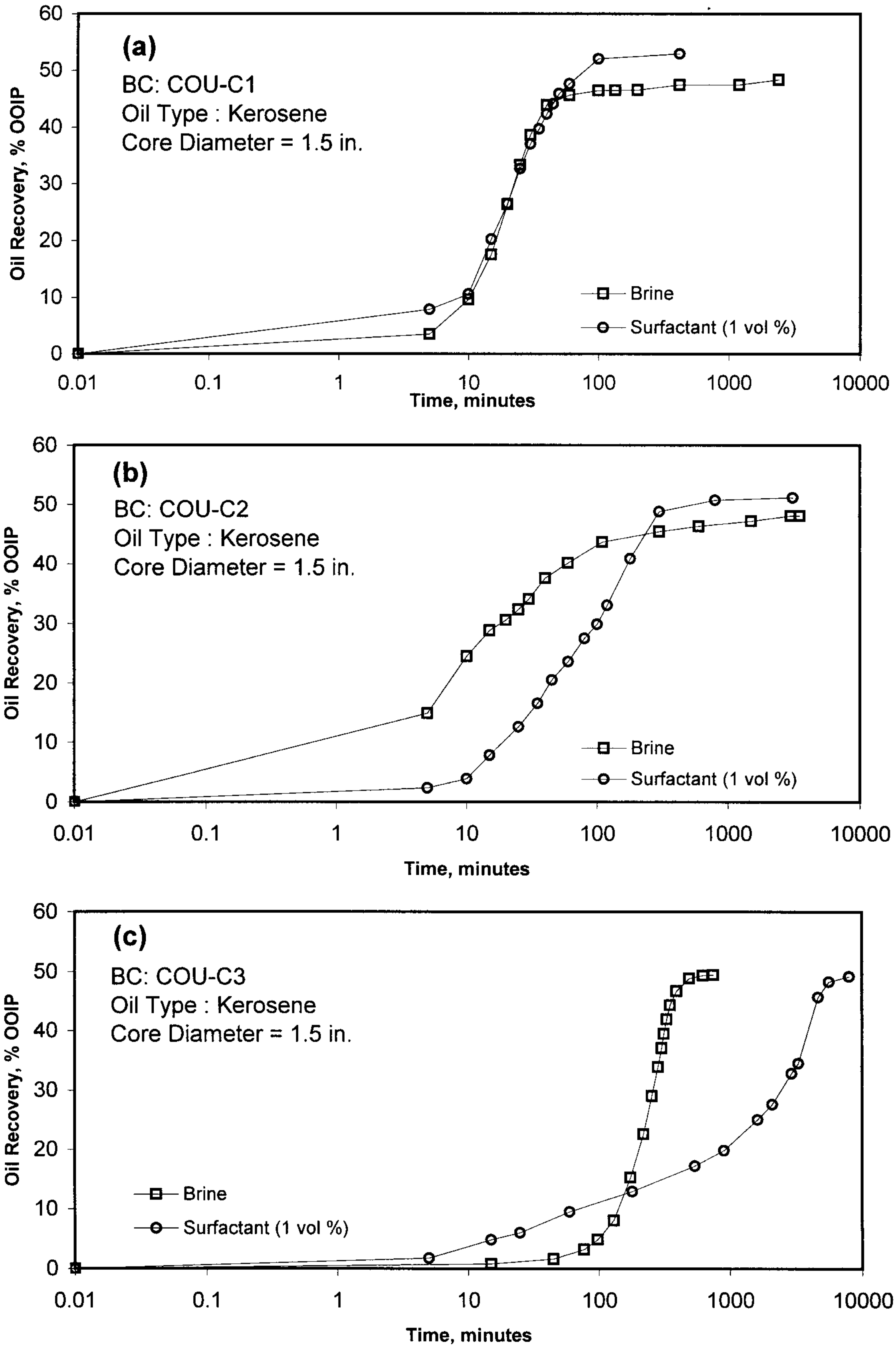

Fig. 6. Counter-current imbibition recovery curves for different types of boundary conditions. (Rock Type: Berea Sandstone, Oil Type : Kerosene, BC: Boundary Condition given in Fig. 1)

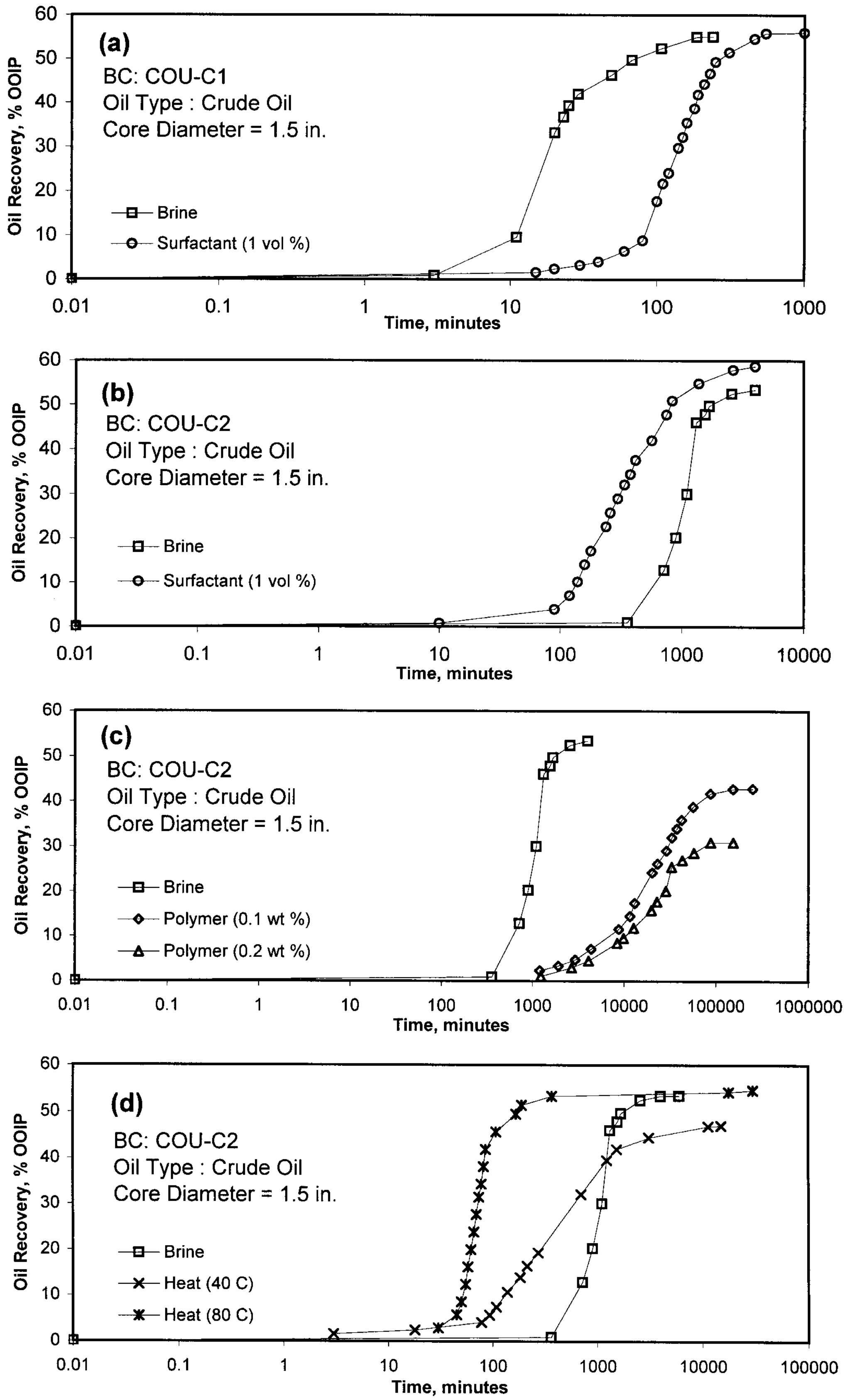

Fig. 7. Counter-current imbibition recovery curves for different types of boundary conditions. (Rock Type: Berea Sandstone, Oil Type : Crude Oil, BC: Boundary Condition given in Fig. 1)