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# A Feasible Experimental Evaluation of Surfactant Polymer Coupled with Direct Foam Flooding on the Oil Recovery Factor

**Afshin Davarpanah***

*Department of Petroleum Engineering, Science and Research Branch, Islamic Azad University, Tehran, Iran*

*Corresponding Email; Afshin.Davarpanah@srbiau.ac.ir

Phone number; +989178546466

Orcid ID; 0000-0002-3697-1808

## Abstract

Optimum selectivity of enhanced oil recovery techniques would play a substantial role in the economic prosperity of petroleum industries which might be virtually eliminated unnecessary expenditures. In this paper, the simultaneous utilization of foaming agent, surfactant polymer (SP), and supercritical carbon dioxide were taken into the investigation under the miscible condition to evaluate the efficiency of each scenario on the cumulative recovery factor, water cut and pressure drop. According to the results of this experimental evaluation, SP-foam flooding had witnessed the highest blockage which is caused to have the maximum recovery factor due to the mobilization of more oil volume in the low permeable pores and cracks. Furthermore, the utilization of surfactant with supercritical carbon dioxide had experienced the least recovery factor regarding the insufficient foam generation which is led to less mobilization of oil phase in the pore throats.

**Keywords:** Surfactant Polymer, Supercritical Carbon Dioxide, Foaming agent, Blockage, Recovery factor

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## 1. Introduction

Primary recovery mechanisms are called natural driving methodologies. In this stage energy that is supplied by the natural drives of the reservoir such as water pressurization and gas cap drive push the hydrocarbons up to the surface of a production well. There are five principle natural driving mechanisms that mentioned as Solution gas drive mechanism, Gas cap drive mechanism, Water drive mechanism, Gravity drainage mechanism and Combination of these methods. In these methodologies, the reservoir pressure would be maintained relatively constant[1-5]. Water drive mechanism is one of the most important natural driving mechanism and also 70 to 80 percent of oil and gas production is a result of this natural mechanism. In the formations that include oil in the uniform porous media continuously cover a large area, major volume of aquifer (especially salty water) surrounded this formation. Increasing and maintaining the reservoir pressure is a common method to increase reservoir oil recovery and it happens in different ways by injecting a miscible or immiscible fluid[6-16]. Selection of this injected fluid is usually depends on availability, price (economy) and geological reservoir characteristics. Furthermore, routine wells are generally used for injection and production reasons also, facilities are used in recovery phase that is helped to perform this technique in terms of time and expenditure. In addition, $CO_2$-EOR techniques give petroleum industries the chance to have an extensive knowledge of improving $CO_2$ capturing and storage methods (CCS) to lessen the greenhouse gas emissions by storing $CO_2$ in geological reservoirs, that is to say that, $CO_2$ injection scenarios in terms of high volume of oil which is returned to the production facilities, greenhouse gas emissions through future geological storage of $CO_2$ has been reduced. All of the enhanced oil recovery techniques would not be a good adaptation in every reservoir characteristics regarding the poor value of sweep efficiency which is caused by premature breakthrough, the override of gravitational forces, and viscous fingering. Therefore, waterflooding and gas injection would not be a selective technique to achieve the maximum recovery[17-24]**.** The ability of gas in injection processes is contained its high potential to have a lower viscosity and density which is microscopically displaced with the oil phase and subsequently improve the recovery factor. The widespread utilization of foam technology as a gas dispersion in the continuous phase (liquid phase) and to form a lamella thin film which is made by a discontinuous gas phase. Moreover, the introduction of foamed gas in the reservoir, vertical and aerial sweep efficiency has fundamentally improved which is the reason of gas relative permeability reduction and increase of apparent viscosity for the gas phase to make lamellae films. Therefore, the adequate efficiency of foam flooding recovery processes would seriously obstacle by the retention of surfactant agent and the stability of foaming agent which is widely reported in literature[25-36]. Another chemical EOR methods which is considerably influenced the oil recovery enhancement especially heavy oil reservoirs is related to simultaneous injection of surfactant-polymer (henceforth; it is called as SP flooding) in the combination with water which is flooded into the reservoir[37, 38]. The procedure of efficient displacement in this technique entail the following steps. Firstly, the surfactants have the potential ability to react with crude oil and the formation brine to generate in situ micro-emulsion. Thereby, the capillary number is reached the maximum value and the remained oil would be easily mobilized according to the capillary desaturation curve (CDC). In the second phase, the polymer particles have modified the mobility ratio within the displacing phase thickening and to alleviate the impact of permeability alteration which is profoundly enhance the total sweep efficiency. Furthermore, the considerable influence of polymer particles presentation in the injected fluids would assist in the reduction of surfactant adsorption on the reservoir rocks. To grasp the importance of minimum miscibility pressure (MMP), a vast majority of laboratory experimental evaluations are widely reported in the literature

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to investigate the principles of these methods to provide such measurements for calculating the oil recovery factor, that is to say that, the administration of empirical correlations and equations of state are also possible for MMP calculations as well. Because rising the injected fluid interface with those regions which they are un-sweep and clear enough (those regions which are not severely affected by upward gas mobilization especially in the gas injection procedures and downward water mobilization in the time of waterflooding). According to the administered techniques to improve the efficiency of foam flooding, adding the polymer particles in the foam solution would be considered as the preferable techniques in terms of technical and economical purposes. By the addition of HPAM in the foam solution which is known as Polymer Enhanced Foam (PEF), the lamella strength in the surface could be enhanced and subsequently the membrane liquid drainage is weakened and the diffusion of gas phase would reduce[19, 39-46].

## 2. *Materials and Methods*

### *2.1. Materials*

Core plug; the provided core samples which is used in this experimental evaluation are extracted from the one of the sandstone reservoirs in the Pazanan oilfield of Iran with the approximate length of 8.24 cm and 4.1 of outer diameters. The permeability and porosity distribution of the utilized corefloods for this study are statistically depicted in Table 1.

Performed Gas; carbon dioxide which is used in this experiment was purified to the percent of 99.99% to be administered in the flooding procedures.

Brine; the brine A which is used in the combination of surfactant polymer supply has the salinity of 6000 ppm of NaCl salts and Brine B that is used for the coreflood experimental investigation are prepared with the 22000 ppm salinity.

Operated crude oil; the administered oil in this study is provided from Pazanan oilfield with the following properties that is mentioned in Table 1.

### *2.2. Core Flooding Experiment*

The components of coreflood equipment contained core holder which is supplied with the fluids variation by displacement pumps that is located in horizontal section and the core plug is placed in to allow the fluids as the input or output forms to the core plug at determined pressure and temperature, foam generator, and fluid accumulators. The pressure differentiations are measured adequately by the pressure transmitters which are placed at the input and output of core holder. The operational temperature which is used in this experiment is 315 K to be more adapted with the reservoir circumstances. Since then, the following steps are done sequentially to commence the experimental evaluation;

- ✓ The extracted core plugs are dried at the temperature of 350 K for three days and then the permeability of gas phase and the porosity of core plug are measured by the Permeameter-Porodimeter device. Next, the core plug under the confining pressure of 3000 psi is placed into the core holder and then it is vacuumed to eliminate the air for about one day.
- ✓ To have a steady state flow in the core plug, it is saturated with brine B and the permeability of liquid phase is determined by the application of Darcy's law in the single phase situation.
- ✓ To attain the saturation of residual water, the crude oil with the rate of 0.5 mL/min is injected to the core holder to reach the water cut of 1%. Since then, the core plug is remained for about one day to be stabilized.

- ✓ The water flooding procedures are done with the flow rate of 0.6 mL/min of brine B to establish the saturation of residual oil.
- ✓ The specified volume of chemical and carbon dioxide is injected to the core samples on the both conditions of immiscible and miscible at the flow rate of 0.6 mL/min to reach the water cut of 99%.

## *3. Results and Discussion*

### *3.1. Coreflooding Experimental Evaluation on the Miscible Circumstances*

To conduct an investigation on the extracted core plugs on the miscible circumstances to consider the profound impact of carbon dioxide, surfactant polymer and its combination with foaming agent, three core plugs were utilized as a separate mode. The results of this investigation and the recovery percentage in each core plug are statistically demonstrated in Table 1.

**Table 1.** Coreflooding experimental evaluation on the miscible circumstances

| **Experiment** | **#1** | **#2** | **#3** |
|---|---|---|---|
| **Porosity (%)** | 16.24 | 16.83 | 16.57 |
| **Gas Permeability (mD)** | 389 | 423 | 417 |
| **Brine Permeability (mD)** | 354 | 328 | 335 |
| **Tertiary Mode** | A | B | C |
| **Volume of gas and chemicals** | Supercritical $CO_2$+ 0.45 PV of SP | Supercritical $CO_2$+ 0.45 PV of SP | Supercritical $CO_2$+ 0.45 PV of SP |
| **Injection schemes** | 1 PV foam | (0.2 PV $CO_2$+ 0.25 PV SP) | (0.4 PV foam+ 0.2 PV SP) |
| **Initial oil saturation (%)** | 54.7 | 56.3 | 53.8 |
| **Waterfloods recovery (%)** | 31.5 | 32.4 | 31.9 |
| **Tertiary oil recovery (%)** | 24.8 | 23.6 | 20.1 |
| **Maximum Pressure drop (psi)** | 92.4 | 67.9 | 105.6 |
| **Total oil recovery (%)** | 56.3 | 56 | 52 |

### *3.2. Pressure Drop Measurement*

To measure the pressure drop in the obtained core plugs from the studied field, the pore volume injection was divided into two different stages as secondary and tertiary recovery performances for three investigated scenarios on the three core samples. As can be seen for three core samples in Figures 1-3, the pressure drop had increased dramatically in the first period of brine injection which is clearly depicted the mobilization of more oil volume from the core plug to the outlet of the core holder. On the contrary, according the pressure drop figures, at the pore volume injection of 0.1 the pressure drop had decreased slightly up to the end of waterflooding which is elaborated by the breakthrough phenomenon that is related to the differentiations between the viscosity and density of the crude oil and brine. In respect of the way, in this stage the oil could not be efficiently displaced until the saturation of residual oil was became steadily and this is why the urgent need of tertiary techniques are being sensitized. In the first part of the investigation, the $CO_2$ foam (in the period of 1.4 - 2.1 pore volume injection) was directly injected to the core samples which has performed as a dramatic rise in the pressure drop to its maximum value of about 90 psi. Two possible reasons for this drastic pressure drop increase might be considered; firstly, the extreme high value of apparent viscosity which performed as a push force for the oil phase to be more mobilized. Secondly, the high potential of foaming agent to enter the large pores to operate as a blocking agent which helps to the approximately small throats and pores to be more producible in the recovery processes and subsequently increase the sweep efficiency and recovery displacement. Moreover, as it is clarified in the foaming processes, it had experienced a fluctuation in pressure drop trend and this issue was related to the regeneration and collapse of $CO_2$ foam in the porous media. To achieve the complementary utilization of $CO_2$, and chemical materials the chase brine injectivity has performed. Thereby, at the first stages of chase waterflooding, the pressure drop

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had risen for a short period regarding the throat blocking which is caused by the polymer adsorption and recreation of foams in the pores. Due to the much more volume of chase brine injection, the blockage phenomenon was being decreased owing to the rise of chemical losses in the pore throats which is caused to gradual decrease of pressure drop. The pressure drop profile for the $CO_2$ foam injectivity has been schematically plotted in Figure 1.

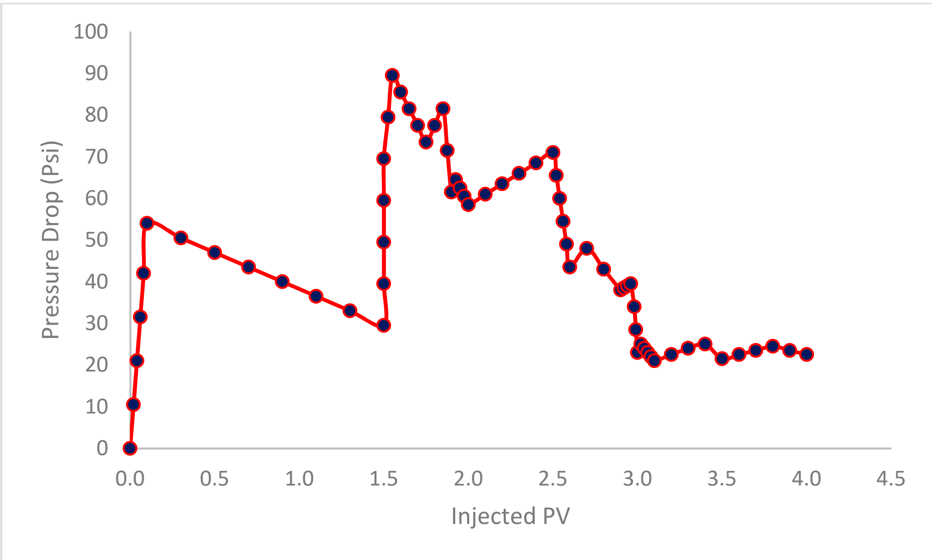


**Figure 1.** Pressure drop profile for the $CO_2$-foam injectivity.

In the second stage of investigation, core sample B which is based on the analysis of simultaneous injection of SP and $CO_2$ in the core plug which is shown that the pressure drop profile had a different pattern than core sample A. In comparison with core sample A, in the first period of water injection, the pressure drop alteration rose slowly with the relative slower fluctuation, and the maximum value of pressure drop in this scenario was measured about 68 psi that is related to the inadequate and improper generation of foam in the procedures. In respect of the way, the inappropriate performances of this scenario was considered as the improper interaction of SP and $CO_2$ regarding the differences of mobility ratios. Another primary differentiation between $CO_2$-

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foam and SP_foam injectivity is that $CO_2$ injectivity after foam generation had led to pressure drop increase while the injection of SP solution caused to pressure drop decrease. As same as core sample A, the pressure drop decline had been experienced in chase brine injectivity for core sample B which is clearly demonstrated that the lower efficiency of foaming production. Therefore, the existence of foaming agent, and polymer adsorption would be a proposed issue to facilitate the regeneration of foaming agent and subsequently caused not to have pressure drop decline which is experienced an approximate steady pressure drop after the 0.2 of pore volume injection. This phenomenon is schematically depicted in Figure 2.

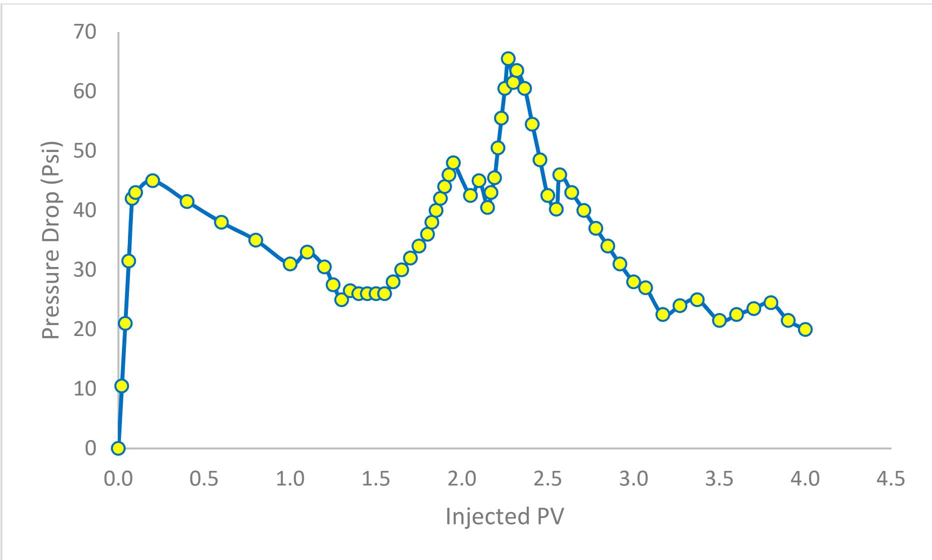


**Figure 2.** Pressure drop profile for the SP-$CO_2$ injectivity.

At the last part of the investigation, the sequential injection of SP and foam are utilized in the injectivity procedures. This injectivity scenario was completely different from core samples A and B due to the significant increase of pressure drop after the injection of foam in the first periods. As the SP would be operated as an unstable phenomenon to decrease pressure drop, the maximum pressure drop after the injection of foaming agent had reached to about 105 psi and its fluctuation

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rate was around 85 psi which was more than other two samples. In respect of the way, this high value of pressure drop clarify that the movement of oil phase is increased dramatically in the injection processes which is caused by the following reasons; (1) regarding the presence of SP solution which had helped in maintaining the foamability phenomenon, the stability of foaming agent had enhanced drastically. (2) the simultaneous existence of foam and SP would cause to alleviate the issue of chromatographic SP separation. (3) mass transfer between SP solution and foaming agent had caused to alleviate the losses of chemicals in a large extent. 4; the unique property of foaming agent to reduce the mobility of supercritical $CO_2$ and subsequent enhancement of displacement efficiency was another privileges of this scenario than other scenarios. On the contrary, after the chase brine injectivity, it was expected to witness a sharp decrease as same as core samples A and B, however, this reduction according to the Figure 3 was seemed to be more slowly. As it is discussed in previous sections, the high potential interaction between SP and $CO_2$-foam due to the residual resistance which is prohibited the quick pressure drop. Moreover, the pressure drop would have stabilized after the pore volume injection of 2.2 which was clearly depicted the attain of residual oil in the reservoir.

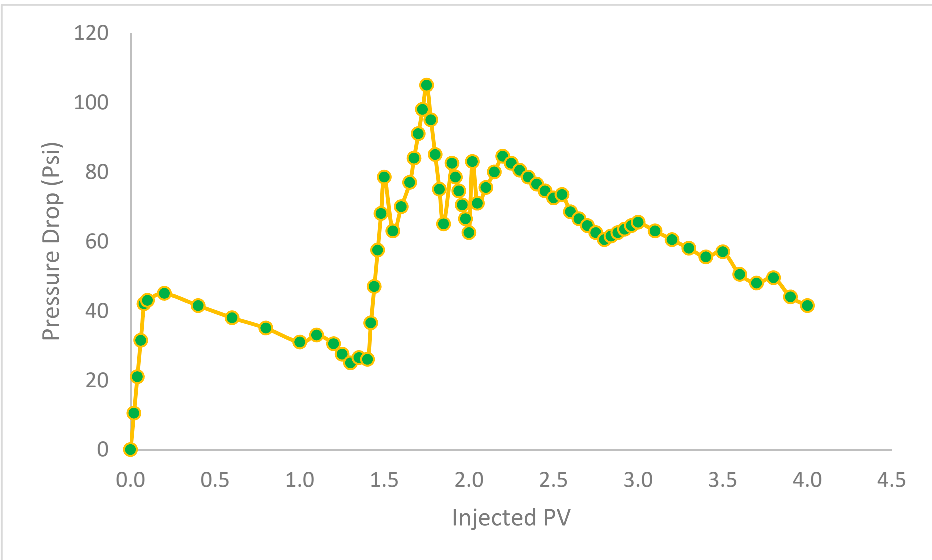

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**Figure 3.** Pressure drop profile for the SP-Foam injectivity.

### *3.3. Cumulative Oil Recovery Measurements*

In this part of investigation, the cumulative oil recovery percentage was evaluated for each injectivity scenario which is clearly depicted in Figure 4. Before the commencing of the injectivity scenarios, water flooding recovery for three core samples are measured about 34 % in average at the water cut of 99%. According to the results of this experimental evaluation which is based on the comparison of each injectivity scenario are stated that the most production of incremental oil was for core sample B (it is about 32.4%) and after that core samples C and A with 31.9 % and 31.5 % are in the next stages respectively. Since then, the tertiary recovery techniques were taken into the investigation to measure the overall recovery factor. As it is evident from Table 1, for core sample A which is utilized the foam directly injected into the core plug and further reduction of oil-water mobility ratio. Therefore, the displacement efficiency of miscible $CO_2$ flooding had reached its maximum value. That is to say that regarding the collapse of foam which is caused by the invasion of oil phase, lamellae breakdown, and the presence of chemicals adsorption in rock surface of pore throats, the foaming stability had drastically decreased especially at the last period of injectivity in the chase brine injection that is severely impact the efficiency of tertiary recovery. Although, foaming agent has the highest performances among all the chemical materials, due to the inadequate interaction between SP and $CO_2$ which had led to producing the insufficient volume of foam, core sample B had the lowest tertiary oil recovery. In respect of the way, under the miscible condition, SP has imposed detrimental effect on the value of total recovery factor. On the other hand, regarding the high potential of SP and foam performances in the reservoir characteristics, core ample 3 has provided the highest value of tertiary recovery factor. Consequently, according to the concepts of SP-foam, it is of elaborated that combination of these

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chemicals would virtually eliminate the existed problems of other techniques and it became as a prioritized method rather than utilization foam spontaneously.

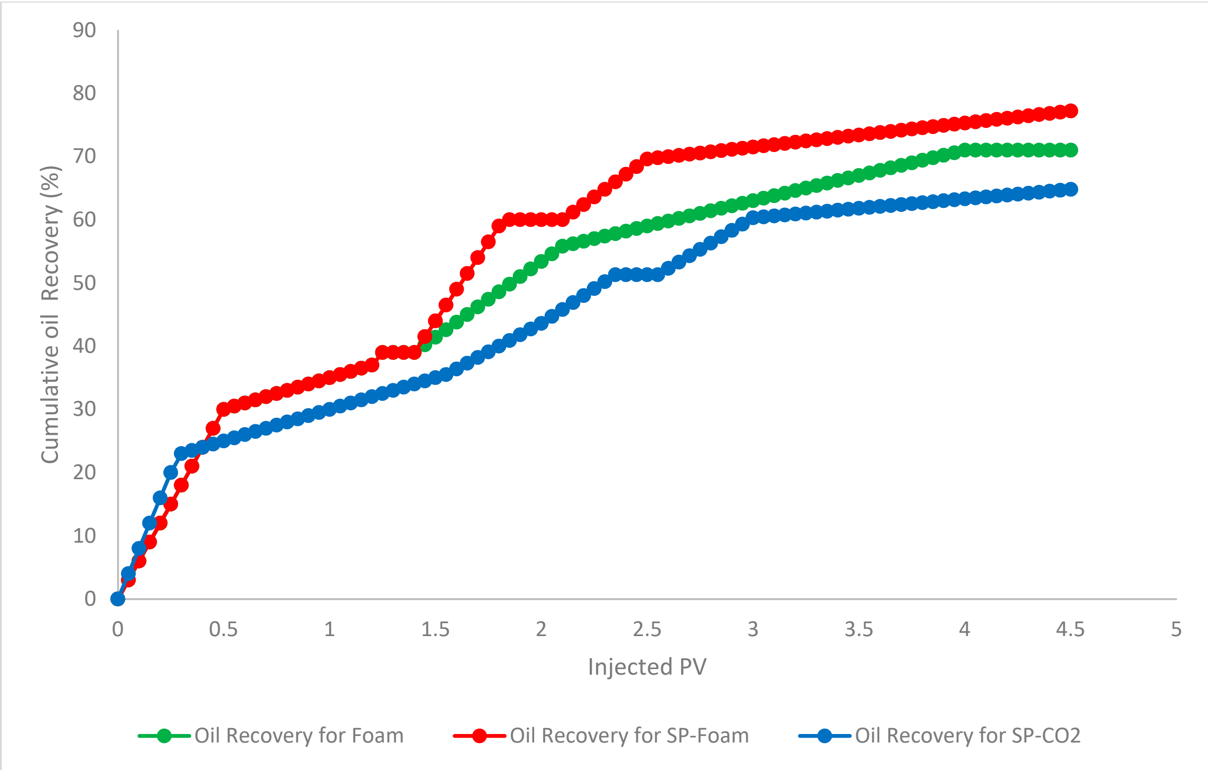


**Figure 4.** Cumulative oil recovery for three investigated injectivity scenarios.

### *3.4. Water Cut Measurements*

In this part of study, the water cut measurement were taken into the evaluation to compare for each injectivity scenario. As can be seen in Figure 5, the breakthrough of water phase had occurred after the 0.35 and 0.25 pore volume of brine injection which is explicitly described by the viscosity differentiations between crude oil and brine. After the breakthrough, the water cut was risen slightly that had led to produce of residual oil and at this stage the water cut percentage is remained about 99 %. According to the core sample A, the water cut had reduced drastically in the first period of direct injection of foam to the core plug; it was about 58% which is elaborated as the more value of oil recovery factor due to the existence of lower water supply. After the injection of foaming agent on the core plug in the pore volume injection of about 0.25, the water cut had increased unceasingly and subsequently had led to oil production decline which is considered as the collapse of foam and further pore throat blockage. Thereby, the maximum percentage of water cut in this scenario had reached to around 93 %. Since then, core flood B has taken into the investigation to measure the value of water cut. As it is evident, the water cut pattern for this core sample was similar to core sample A with a far less trend. Due to the alternative injection of $CO_2$ and SP on the core plug which is caused the lower efficiency of generated foam, the water cut pattern had experienced a fluctuation trend. Moreover, the lowest water cut percentage is related to the core sample A that is about 57% and it had increased dramatically at the end of chemical and $CO_2$ flooding which was remained approximately 96%. Since then, this value had been experienced a stabilized percent about 98.5 % on the chase brine injectivity. For the core sample C, the water cut percentage had altered and in spite of core sample B, the production of water in the presence of SP and foam was declined to reach its minimum value of 51%. Moreover, in this injectivity scenario, regarding the highest blockage in the pore throats, it experienced the lowest water cut among three injectivity scenarios.

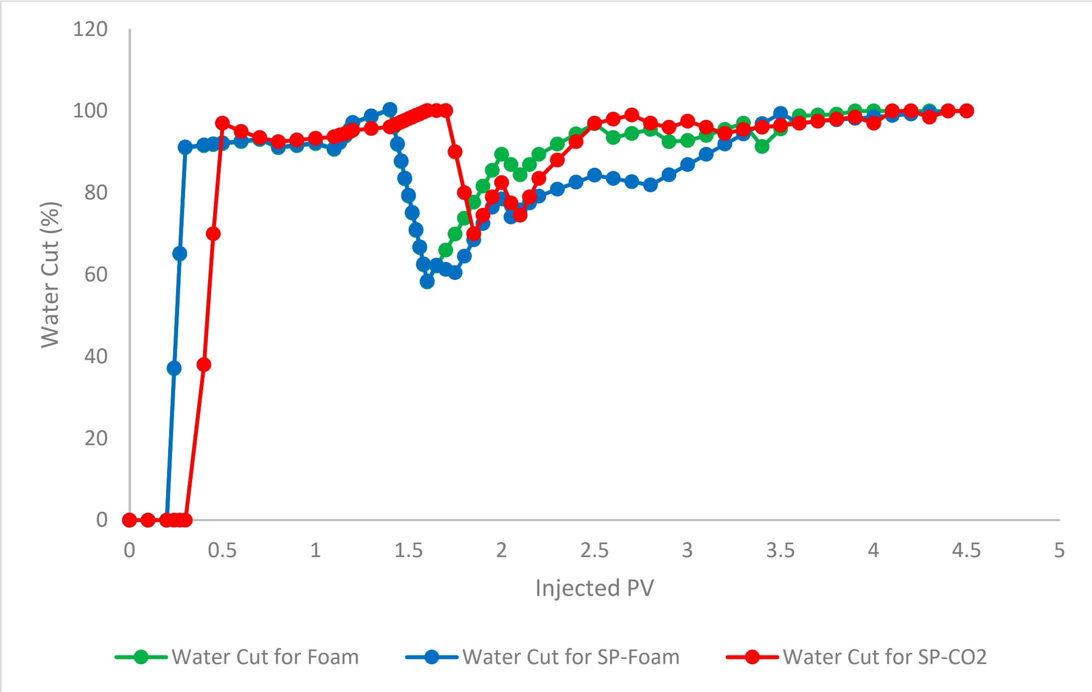


**Figure 5.** Water Cut Percentage for three investigated injectivity scenarios.

## 4. Conclusion

In the miscible condition which is used for this experimental evaluation, the following conclusions are mainly proposed;

- ✓ SP-Foam flooding had witnessed the highest recovery factor due to the highest pore throats blockage which enables the fluids of low permeable layers to be more mobilized.
- ✓ Direct foam flooding and SP-$CO_2$ flooding had performed the lower recovery factor due to the lower foam generation and subsequently lower blockage in high permeable layers.
- ✓ SP-Foam scenario had provided the highest pressure drop which is caused by the more volume of oil movement.

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