Heavy Oil Recovery from Sandstone Reservoirs in the Mid-Continent Region Using Preformed Particle Gel Enhanced Surfactant*

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Abstract

Fractured sandstone reservoirs in the Mid-Continent Region (Kansas, Oklahoma, and Missouri) contribute to heavy oil production in the USA. The fractures in these reservoirs can create significant permeability anisotropy, which cause any water or chemical flooding to move preferentially into void space conduits or higher permeability streaks zones, leaving behind a considerable amount of oil in the rock matrix. In this article, we propose the combined method of preformed particle gel (PPG) treatment with surfactant flooding.

We studied this technique using a series of core flooding experiments. In the first set of experiments, surfactant and PPG were injected together into fractured Berea Sandstone slabs. In another set of experiments, PPG was injected through the fracture followed by slug of surfactant. Before the experiment, the wettability of the Berea slab was altered to oil-wet using chemically grafting silane molecules treatment to simulate reservoir conditions. Results showed that PPGs propagated through the millimeter size fracture and partially plugged it causing a reduction in fracture permeability. The surfactant solution has been filtrated into the sandstone slab matrix and possibly reduced the interfacial tension between oil and water, thus reducing the capillary forces and increasing the fluid flow in the low permeability matrix. Oil recovery of 33-43% of the residual oil bypassed by initial water flooding was recorded

This combined method can provide a practical and cost-effective solution to small operators in the Mid-Continent Region where heavy oil production is hindered by the complex geology and wrongful practice of aggressive water-flooding, which caused the early breakthrough of water. We believe that this method could be suitable where millimeter size fractures and channels can be plugged by PPG.

Introduction

The ultimate recovery of oil from fractured sandstone reservoirs in the Mid-Continent Region is affected by facies-type, small-scale sedimentary structures, bedding boundaries, intergranular small-scale permeability barriers, and diagenetic changes (internal architecture) commonly identified as "heterogeneities" within the sandstone body (Olsen and Johnson, 1993). These heterogeneous bodies restrict the recovery of oil from hydrocarbon-rich matrices because the flooded water or chemicals will bypass these matrices and travel along the easier paths towards the producer well. Over the years several enhanced oil recovery (EOR) projects have been implemented in the area with nominal or no success. The main reason for most of these failed EOR projects is conformance problems which prevent the displacement fluids from contacting the oil in the reservoir. To mitigate these problems we present a combined method of PPG treatment and surfactant flooding.

Surfactant reduces residual oil in the swept area and improves the displacement efficiency (ED) by reducing the capillary and interfacial tension (IFT) between oil and water. The major problem with surfactant injection is that the surfactant primarily enters fractures or super-permeable zones/streaks, which will cause it to break through early or have little opportunity to enter low-permeability matrix to contact the large amount of oil remaining there.

PPGs are cross-linked polymeric 3D networks that can absorb several hundred times their original weight. Commercial PPGs are normally millimeter-sized sugar-like hydrophilic hygroscopic substances that are white-light yellow or brown color (Bai et al., 2013). PPGs, in oilfield terms, are gel particles formed on the surface prior to injection underground. When immersed in water or aqueous solution, gel particles absorb to their equilibrium volume and do not dissolve. Because PPGs are relatively low cost, operationally easy, and environmentally friendly, they are gaining attention and popularity for use in conformance-improvement treatments and have been applied successfully for nearly 15 years (Coste et al., 2000; Bai et al., 2007a; Bai et al., 2013).

Surfactant flooding can increase the ED but has little or no effect on the sweep efficiency (ES). PPGs treatment has been applied successfully to control conformance in more than 4,000 wells in China (Bai et al., 2013); however, the technology can only be used to plug fractures or super-K channels to improve the ES and has little effect on the ED. We propose investigating the idea of coupling PPG treatment and surfactant flooding into one process, thus bypassing the limitations of each method when used individually. The combined method will improve both the ED and the ES and thus the overall cost-effectiveness of EOR.

Experimental Methods

Materials

1) 1.0 wt. % NaCl was used for flooding and to prepare swollen PPG.

2) A commercial PPG called Cerogel PPG-746 was used for the experiments. The dry PPG samples had a mesh size of 60 to 70.

3) Igepal$^®$ CO-530, a commercial nonionic surfactant, was used for the experiments.

4) A heavy mineral oil (Paraffin oil) with a viscosity of 165 cp was used to represent heavy oil.

5) Berea Sandstone cores with an average porosity of 21.8 % and a permeability of 154 mD were used for the experiments, Figure 1. Table 1 summarizes the parameters of 10 core slabs. The cores were treated with toluene and silane to change their wettability from water to oil wet

Experiment Apparatus Design

Semi-transparent fracture model Figure 2 shows the schematics and picture of the model used in the experiments. The model is constructed of two acrylic plates with a rubber O-ring between them. Bolts and nuts are used to fix the two plates and shims to control the fracture width.

A long square pocket (2.0 inches wide, 9.0 inches long, and 1.0 inch deep) was drilled in the center of one side of one of the acrylic plates; a piece of Berea Sandstone core was fixed into this pocket using epoxy. The model is transparent on one side to make the movement of the PPG and surfactant clearly visible. In the plate on the fracture side, four equally spaced holes were drilled for pressure recording and injection/discharge.

A pressure sensor was mounted at each of the first three holes to acquire the pressure change during the experiments. On the other plate, one hole was drilled to serve as an outlet to discharge fluid. The effluent from the fracture and matrix (for open fracture mode) and from the matrix alone (for closed fracture mode) were recorded separately to calculate the oil recovery factor and water cut. A fracture width of 2.5 mm (0.098 inch) was used in the experiment.

Experimental Procedure

We separated the experiment into four segments as follows:

1) Initial water flooding
Brine (1.0 wt. % NaCl) was injected into the fracture inlet to simulate secondary recovery conditions and detect any oil production from the matrix outlet. The brine immediately flowed from the inlet to the outlet of the fracture with almost no resistance. This behavior recovered no oil, and the water cut from the fracture outlet was 100%. The brine was left in the fracture for 24 hours by closing both the inlet and outlet of the fracture; during this time, we saw no spontaneous imbibition of the brine into the matrix rock, thereby verifying that the rock matrix is strongly oil wet.

2) PPG treatment
Two sets of experiments were conducted to examine the PPG treatment process and its ability to improve oil recovery and reduce water production. In the first treatment, the PPG was swollen in 1.0 wt. % NaCl aqueous solution. The swollen PPG was injected through the fracture, followed by surfactant (1.0 wt. % Igepal® CO-530) injection. In the second treatment, PPG was swollen in an aqueous solution of surfactant (1.0 wt. % Igepal® CO-530). Then, the mixture of PPG and surfactant was injected, followed by brine injection.

3) Surfactant treatment

In the first set of experiments, the PPG was swollen in an aqueous solution of 1.0 wt. % NaCl. After placing this swollen PPG, 1.0 wt. % of Igepal® CO-530 surfactant was injected using the same flow rate (2.0 ml/min) to investigate the ability of surfactant to filter into and release the oil from the matrix by changing or modifying the wettability of the matrix rock. In the other set of experiments, the surfactant was utilized as the swelling media for PPG swelling and thus was injected into the model at the same time as the PPG.

4) Final brine flooding

A final batch of brine was injected into the model to test the PPG plugging efficiency and to recover any additional oil that might not have been recovered during the previous treatments. The same flow rate (2.0 ml/min) was used in all of the core-flooding stages.

The following procedures were used during the experiments:

1) An oil-wet core was vacuumed for 6 hours to purge all of the air, the core then was saturated with a heavy mineral oil and aged for 48 hours in an oven at 90 °C (194 °F).

2) 1.0 wt. % NaCl brine was injected through the inlet of the fracture to simulate a water-flooding process. The water cut (fw) and recovery factor (RF) were measured from the outlets of both the fracture and the matrix separately. Brine injection was stopped when the water cut reached 100%.

3) PPG, swollen in 1.0 wt. % NaCl brine solution, was extruded into the fracture. The propagation of the PPG through the fracture was monitored. The fw and RF were recorded from the fracture and matrix outlets, separately. To monitor the oil recovery during PPG extrusion, the PPG extrusion, the process was not stopped until no more oil was produced from the matrix outlet.

4) Surfactant solution, 1.0 wt. % of Igepal® CO-530 prepared in 1.0 wt. % NaCl, was injected through the fracture inlet. The fw and RF were recorded during the injection process.

5) The effluent from the fracture and matrix outlets was monitored.

Note: In the second set of experiments, PPG was swollen in 1.0 wt. % of Igepal® CO-530 and the mixture of PPG and surfactant was injected into the fracture model.

Results and Discussion

First Set of Experiments: PPG Swollen in 1.0 wt. % NaCl Solution

Figure 3 shows the injection pressure profile of the first set of experiments, in which swollen PPG and surfactant were injected separately. The pressure was acquired from the pressure taps mounted in the fracture side of the model. The plot indicates that there was no pressure build-up during the initial water flooding. This is due to the fact that the water channeled directly to the fracture outlet through the open fracture; also, the resistance to the water flow was insignificant. No water penetrated into the matrix.

In the second stage, when the swollen PPG was injected into the model, the injection pressure began to increase during the first PV injected. After that, the pressure fluctuated, with a peak of 60 psi. In the third stage, the surfactant was injected after PPG was placed in the fracture. The pressure dropped suddenly after a very short time because the surfactant solution created a channel in the PPG pack. The channel caused the same outcome seen after the initial water injection into the oil field fracture. In this case, the surfactant moved directly from the inlet to the outlet of the facture, and no surfactant solution was squeezed into the matrix rock. This indicates that this PPG cannot totally block the fracture. A stronger PPG might be required to force the surfactant solution into the matrix.

Figure 4 plots the oil recovery factor for the first set of experiments, in which oil was collected from the matrix outlet. During the initial water flooding, there was no effluent from the matrix outlet because all of the water was directed to the fracture outlet. Therefore, both the oil recovery and the water cut were zero. During PPG injection, the oil recovery from the matrix initially continued to increase to around 24%, and then no further oil was produced. However, after 2.5 PV PPG injection (at the point of 3.5 PV in the curve), more oil was produced. This may have been caused by the pressure increase at that point, as shown in Figure 3.

The mechanism of oil recovery from the matrix was attributed to the forced imbibition during PPG injection. The PPG did not form a non-permeable cake on the fracture surface, which allowed water to penetrate into the matrix. During PPG injection, the build-up of pressure caused by PPG packing in the fracture will increase the fluid flow resistance in the fracture, which can result in a more significant pressure drop from the fracture surface to the matrix outlet. Therefore, the water from the swollen PPG was forced to penetrate into the matrix.

Second Set of Experiments: PPG Swollen in Surfactant Aqueous Solution

Figure 5 shows the injection pressure profile for the second set of experiments, in which PPG and surfactant were co-injected into the model. As the figure indicates, during the initial brine flooding, the pressure profile was similar to that in the first set of experiments; no pressure build-up was recorded. After injecting a total of 0.72 PV water, we did not see any effluent from the matrix outlet, and all of the water flowed directly through the path of least resistance (fracture outlet). The injection was stopped when the water cut from the fracture outlet reached 100%. While injecting the mixture of PPG and surfactant, PPG broke through from the fracture outlet when 1.18 PV PPG was injected. The maximum pressure was approximately 43 psi, which was less than the pressure in the first set of experiments, as shown in Figure 3. This could be attributed to the surfactant working as a lubricant to reduce PPG friction and increase its injectivity.

Figure 6 plots the oil recovery factor during the treatment with PPG swollen in surfactant. Similar to the first set of experiments, during the initial water flooding there was no effluent from the matrix outlet because all of the water was directed to the fracture outlet. When the PPG and surfactant mixture was injected, the swollen PPG propagated through the fracture until reaching the outlet, and the effluent was found from the matrix outlet after 0.81 PV of the mixture was injected.

The maximum oil recovery was 43%, which was higher than that in the first set of experiments (~33%). This was attributed to the surfactant that was forced to filter into the matrix rock, which altered its wettability from oil to water or mixed-wet. Approximately 3.1% of the oil was recovered during the waterflood (after the injection of the PPG and surfactant mixture).

Summary

We ran two sets of fracture flooding tests using open fracture models. PPG and surfactant were injected into the fracture model separately in the first set, and in the second set PPG and surfactant were injected simultaneously into the model by injecting PPG swollen a surfactant solution. The preliminary results reveal the following information:

1) Millimeter-sized particle gel can only enter high-permeability zones/streaks or fractures and cannot form face plugging on the surface of low-permeability zones or fractures; thus, they cause little damage to unswept oil zones/areas.

2) The surfactant solution mixed with PPG is squeezed from gel particles into low-permeability zones/areas where crude oils are trapped by capillary force. The surfactant solution can dramatically reduce the capillary force (IFT between oil and water) and release the crude oil.

3) The combined injection of PPG and surfactant will result in a higher injection pressure gradient in the reservoir because of the high flow resistance resulting from the particles. This increased pressure will produce an additional force to drive surfactant into the matrix or low-permeability areas, thus making forced imbibition practical.

4) The successful development of this technology will provide a more cost-effective method for improving oil recovery and reducing water production for small producers.

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Coste, J.-P., Y. Liu, B. Bai, Y. Li, P. Shen, Z. Wang, and G. Zhu, 2000, In-depth fluid diversion by pre-gelled particles: Laboratory study and pilot testing: Paper SPE 59362 presented at SPE/DOE Symposium on Improved Oil Recovery, Tulsa, Oklahoma, 3-5 April.

Olsen, D.K., and W.I. Johnson, Feasibility Study of Heavy Oil Recovery in the Midcontinent Region (Kansas, Missouri, Oklahoma), Topical report performed under cooperative agreement, No. FC2243FE60149.
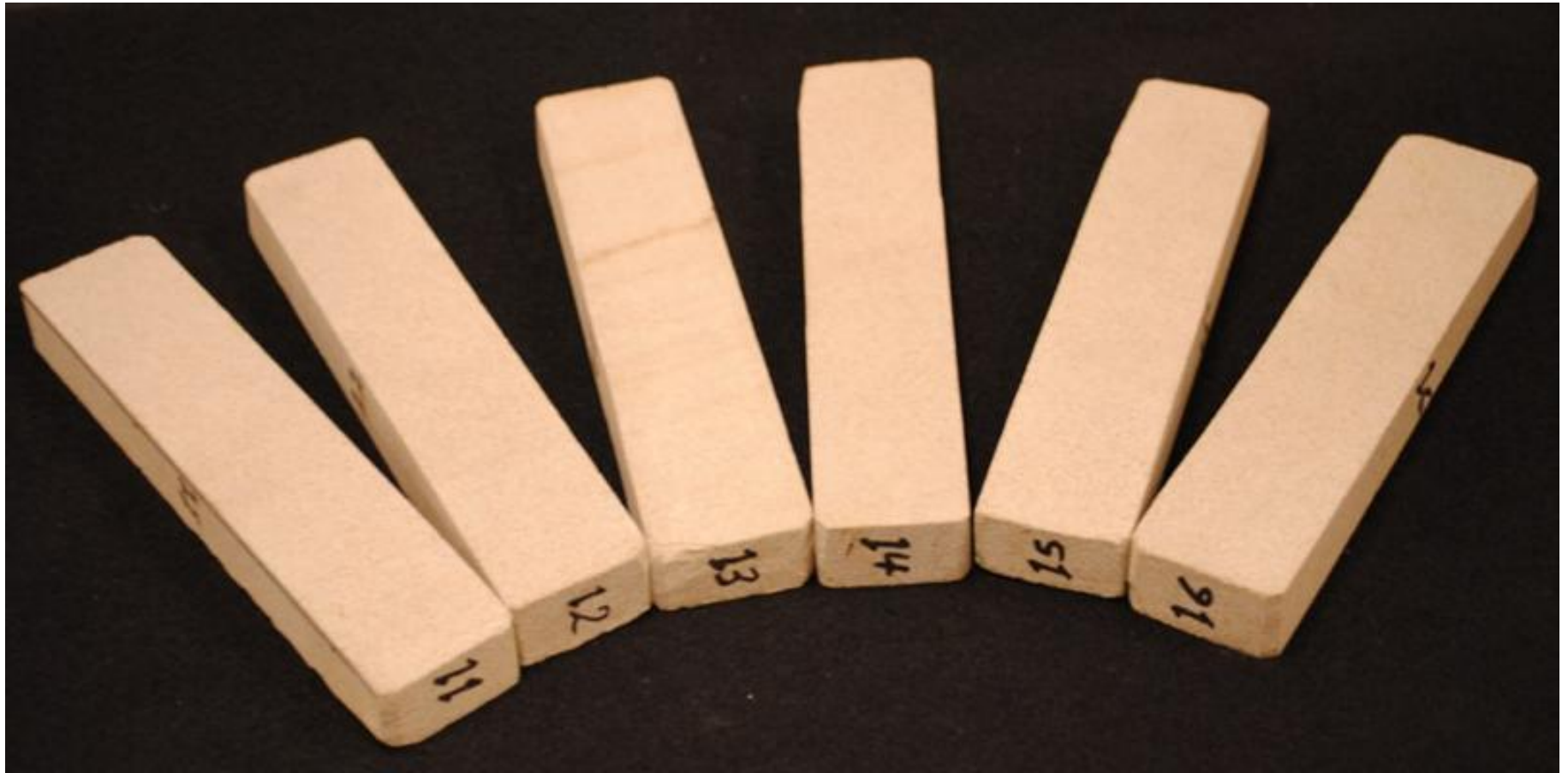
Figure 1. Sandstone slabs prepared for the experiments.
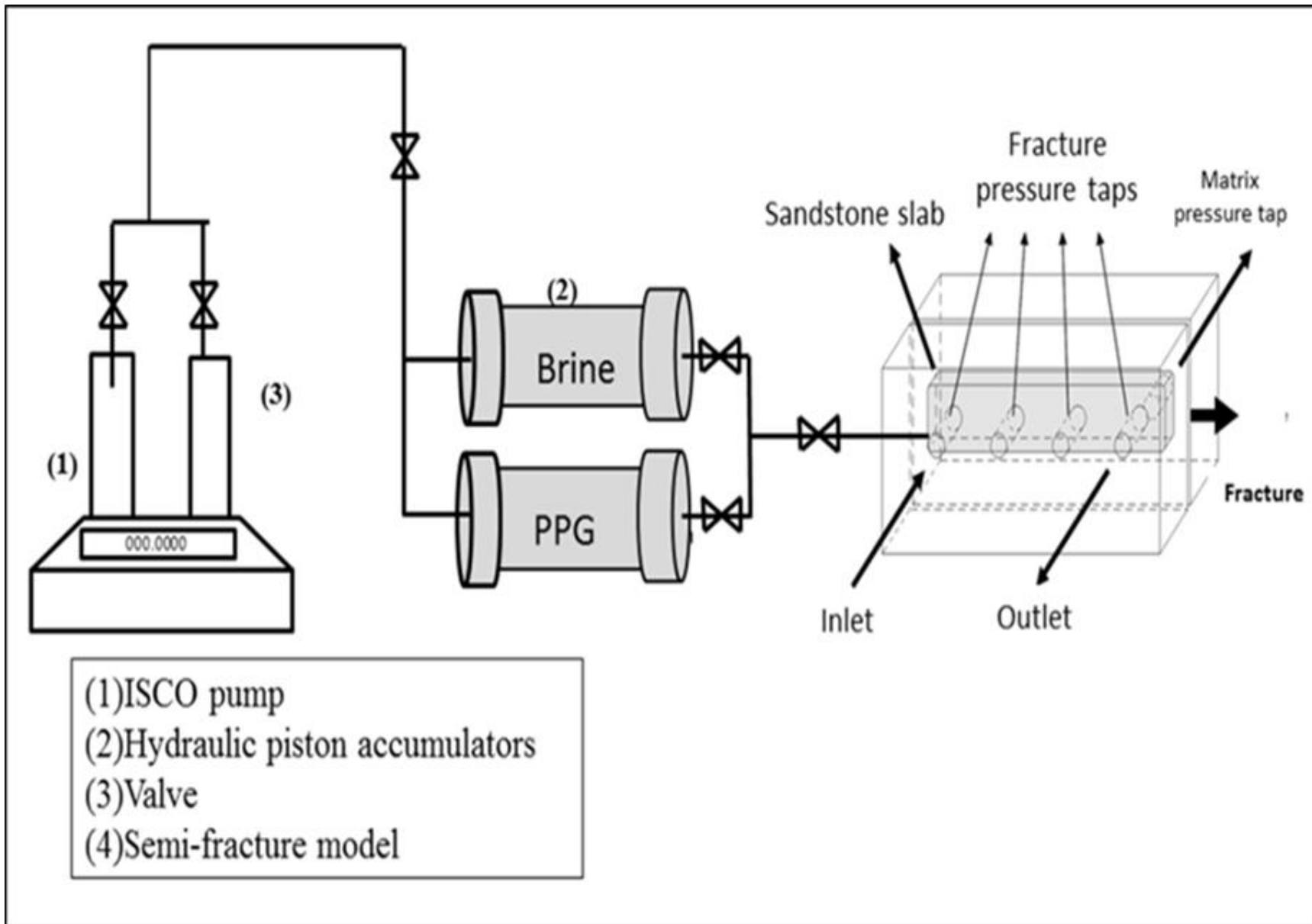
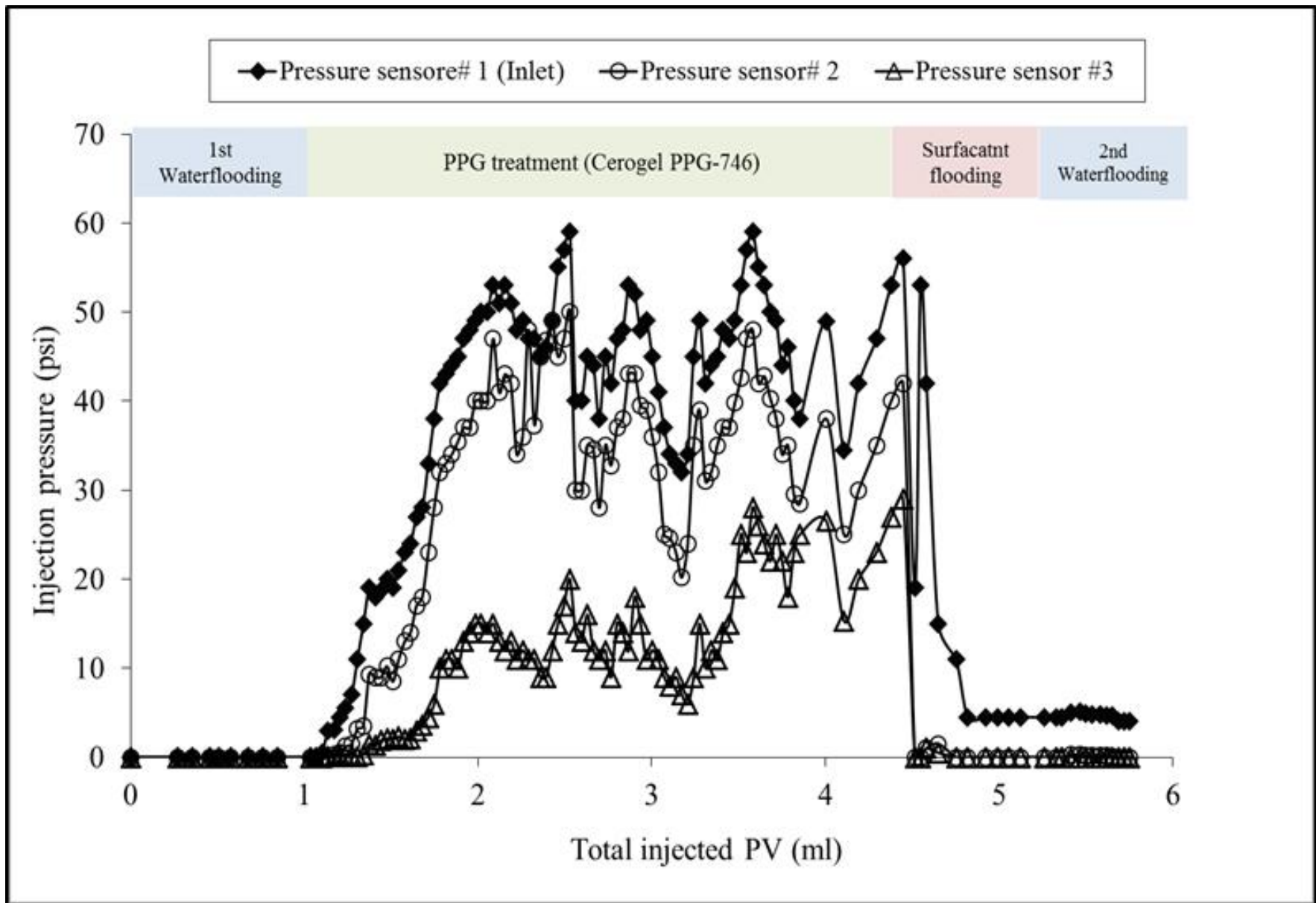Figure 2. Schematic diagram of the semi-fractured model.

Figure 3. Injection pressure profile at different stages of the fracture model.
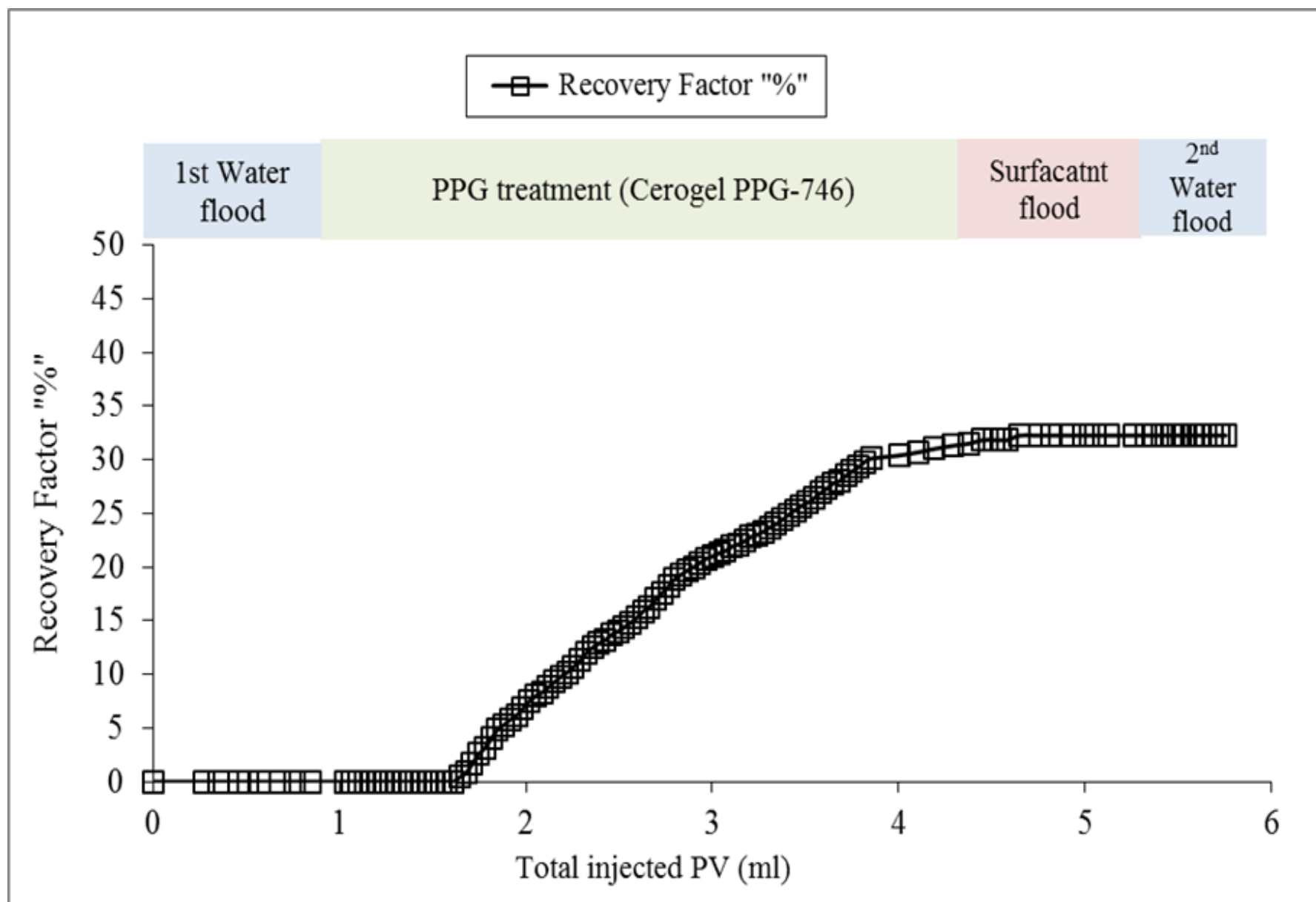
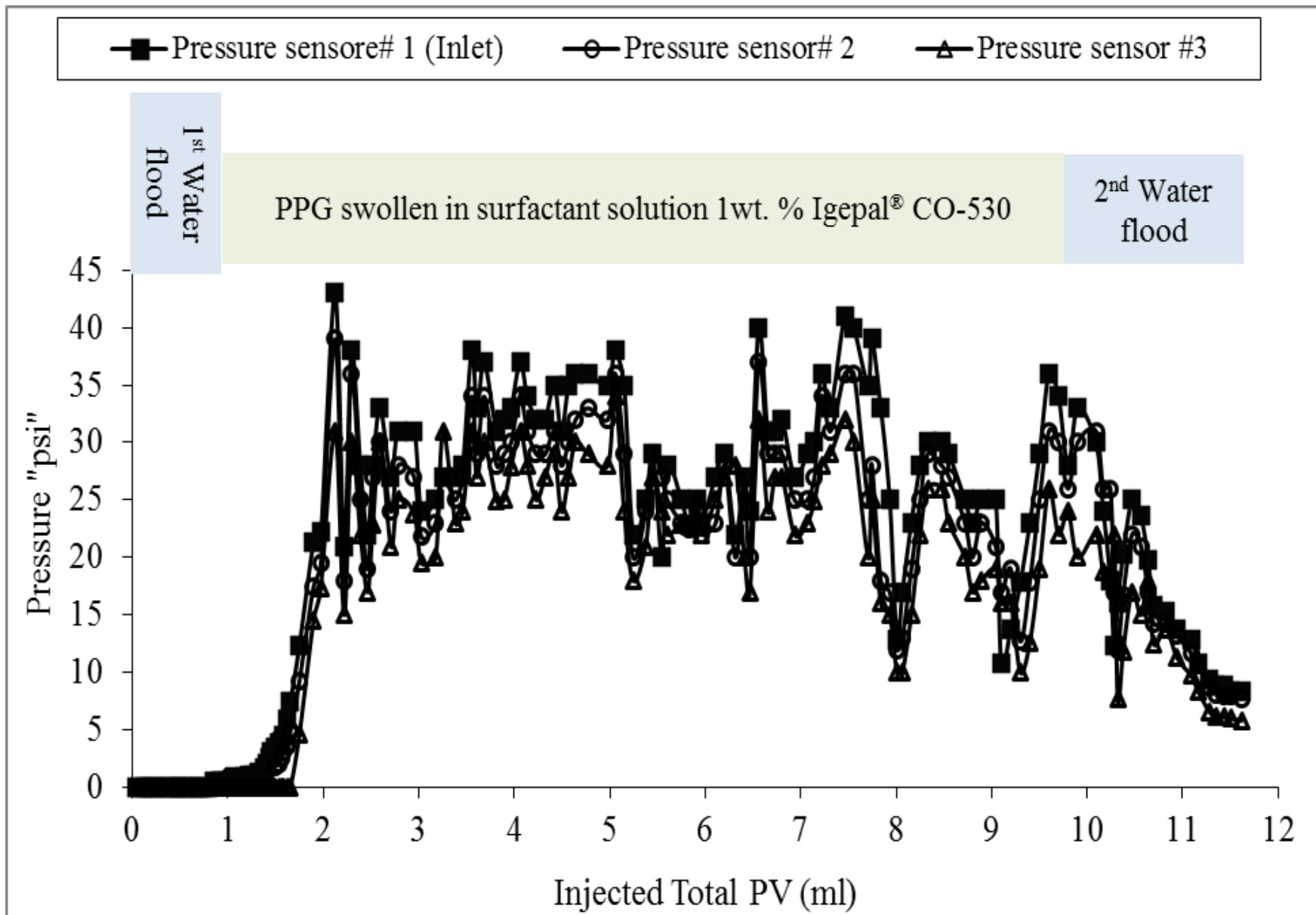Figure 4. Oil recovery factor during treatment with PPG swollen in 1.0 wt. % NaCl.

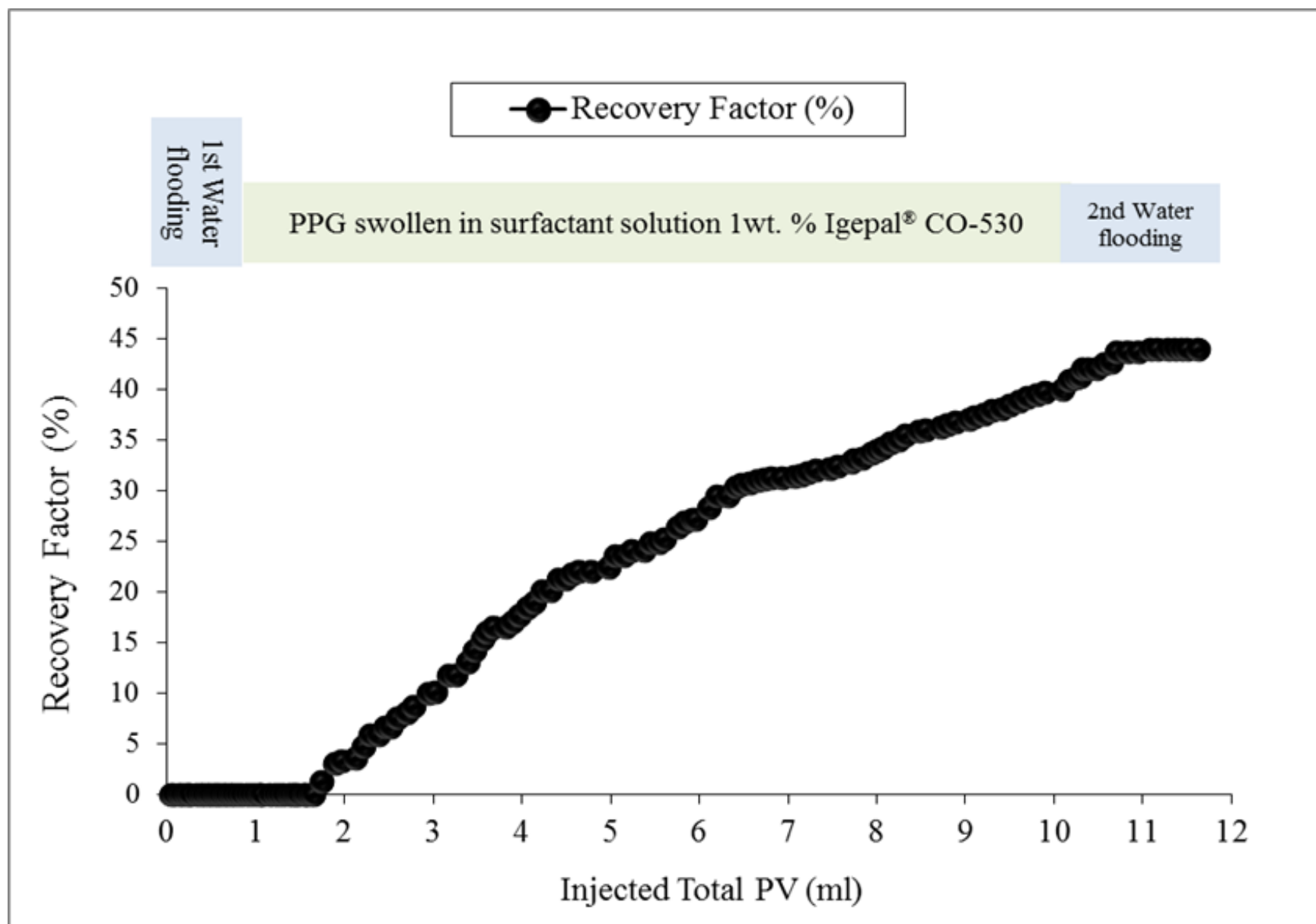Figure 5. Injection pressure profile at different stages of the fracture model.

Figure 6. Oil recovery factor during treatment with PPG swollen in Igepal® CO-530.

Sample #	Length (cm)	Width (cm)	Thickness (cm)	Bulk volume (cc)	Pore volume (cc)	Dry weight (gram)	Porosity (%)	Permeability (md)
1	22.6	4.735	2.133	228.3	49.76	478.08		
2	22.55	4.81	2.108	228.6	49.83	467.69	21.8	154
3	22.36	4.739	2.095	222.1	48.41	452.79		
4	22.45	4.7493	2.119	225.9	49.25	467.91		

Table 1. Dimensions and properties of Berea Sandstone slabs.