AN INVESTIGATION OF THE EFFECTIVENESS OF FOAMED-CRUDE DISPLACEMENT IN POROUS MEDIA

by

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12703-86

ACKNOWLEDGEMENTS

Appreciation is expressed to Dr. Daniel M. Bass, Head, Department of Petroleum Engineering, for acting as thesis advisor and Dr. Ching Huang Wu for his valuable suggestions.

The author wishes to thank the Ministerio de Minas y Energia of Colombia and the Empresa Colombiana de Petroleos for their financial support.

Very sincere appreciation is expressed to my wife, Myriam for her patience and understanding during the period of my graduate study.

A Thesis submitted to the Faculty and the Board of Trustees of the Colorado School of Mines in partial fulfillment of the requirements for the degree of Master of Science in Petroleum Engineering.

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ABSTRACT

An experimental study was made to investigate the effectiveness of using oil-foam (generated from nitrogen, and a .2% solution of kerosine and a surface-active agent, Fluorad (FC-432) to displace in place oil from two consolidated Berea cores. Cores used were 61 cm. long and 5.04 cm. in diameter, with permeabilities of 22 and 81 millidarcies. Test injection pressures ranged from 715 to 1170 psig.

Three main types of displacement tests were performed. These include: (1) conventional waterflooding, (2) tertiary and secondary oil recovery with externally generated oil-foam, and (3) three tests of secondary oil recovery with internally generated oil-foam.

Results indicated that: (1) at 1.0 PV cumulative gas injection, internally generated oil-foam had an average oil recovery increase of 3.5% PV over that obtained by externally generated oil-foam, (2) conventional waterflooding injection recovered 15.4% PV and 11.9% PV more oil (at 1.0 PV gas injection) than externally and internally generated oil-foam, respectively, (3) the change in slug sizes from 11% PV to 30% PV had no influence on the total oil recovery and oil recovery at gas breakthrough, and (4) both internally and externally generated oil-foam showed stability within the cores when used to displace oils.

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1. INTRODUCTION

With the increasing demand for hydrocarbon energy resources and with the high cost of finding new oil reserves, efficient recovery techniques will have to be developed to enhance the oil production from existing reservoirs.

Investigations have been made in consolidated and unconsolidated porous media on the use of water-foam for oil recovery. Fried[9], Holm[10] and Raza[15] found that these foams improved a waterflood or gas drive oil recovery by decreasing the mobility of the displacing phase. Bernard[6] and Minssieux[13] determined that internally or externally generated foams within or without the porous media were more efficient than gas drive, but less efficient than waterflood. Minssieux also found that oil recovery increased as foam quality decreased. The oil recovery by foams was found to be dependent on the ability of the surface-active agent to sustain foam inside the porous media. Other investigators[11,12] studied the mechanisms of foam flow in porous media.

Since water-base solutions were exclusively used for water-foam generation in the above mentioned studies, oil-base solutions have not yet been investigated. This study investigated the use of oil-foams formed by a mixture of nitrogen, an oil-based solution and an oil soluble surfactant, to displace oil from consolidated cores.

2. LITERATURE REVIEW

2.1 Basic Properties of Foams

2.1.1 Physical-Chemical Aspects. Foams are fundamentally colloidal systems of agglomeration of interconnected films which exhibit non-Newtonian fluid properties.[7,9] These interconnected films surrounding the foam bubbles are formed by a dispersion of a gas phase into a liquid phase. When surface-active agents are not present the resulting foams are called "pseudo-foams". When a surface-active agent(s) is present, the foams are called "true foams". True foams are divided into two classes: unstable and metastable. Unstable foams are very short-lived foams, sustained by a weak surface force and their stability is dependent on the surface-active agent concentration. The metastable foams have a good stability characteristic which is mainly controlled by the structure of their surface layers.

The main physical-chemical aspects of foams that are important to oil displacement performance are foam stability and viscosity. These main aspects will be discussed in the following sections.

2.1.2 Foam Stability. The stability of foams depends primarily on the redistribution of the bubble sizes, and the conditions of film thinning. The first effect is caused by the pressure differential across the films. Film thinning is caused by foam drainage which is induced by gravitation and suction along the Plateau Borders (PB)[1]. As drainage takes place the foam properties are drastically affected. Film ruptures cause foam instability. Since this rupturing of films is mainly controlled by the radius of the bubble and film surface tension, it is intimately related to the changes in bubble size and film thinning. When the bubble sizes are subjected to reduction of film thickness and surface tension, the bubbles are likely to rupture. A theory was proposed by Gibbs and Marangoni[1] to explain how the migration and redistribution of surfactant in films during bubble size changes, help to maintain the stability of the foam.

Foam stability also depends, to a lesser extent, on the following factors: Quality and viscosity of the foam, and type and concentration of surface-active agents.

2.1.3 Foam Viscosity. Marsdsen, et al[12] measured the foam viscosity by a Fann VG Meter viscometer and found that foams have a tendency to develop high viscosity values, which are dependent on the surface-active agent concentration and foam quality. They also found that for water-foam systems, viscosity values ranged from 50 to 500 centipoises. Minssieux[13], using a Fawn and Eppretch coaxial cylinder viscometer, observed that foam viscosity increases with the increase in foam quality and decreases as shear rate increases; in this manner he demonstrated the pseudoplastic nature of foams. By applying Darcy's law to the entire foam flow in the core, Minssieux also found that, in the presence of oil, water-foam viscosity decreased linearly as foam quality increased.

Mitchell[14] studying foam viscosity in capillary tubes stated that foam viscosity was independent of shear rate for qualities between zero and 54% where foams show a Newtonian behavior; foam viscosity was found to be independent of quality at values of shear rate approaching infinity.

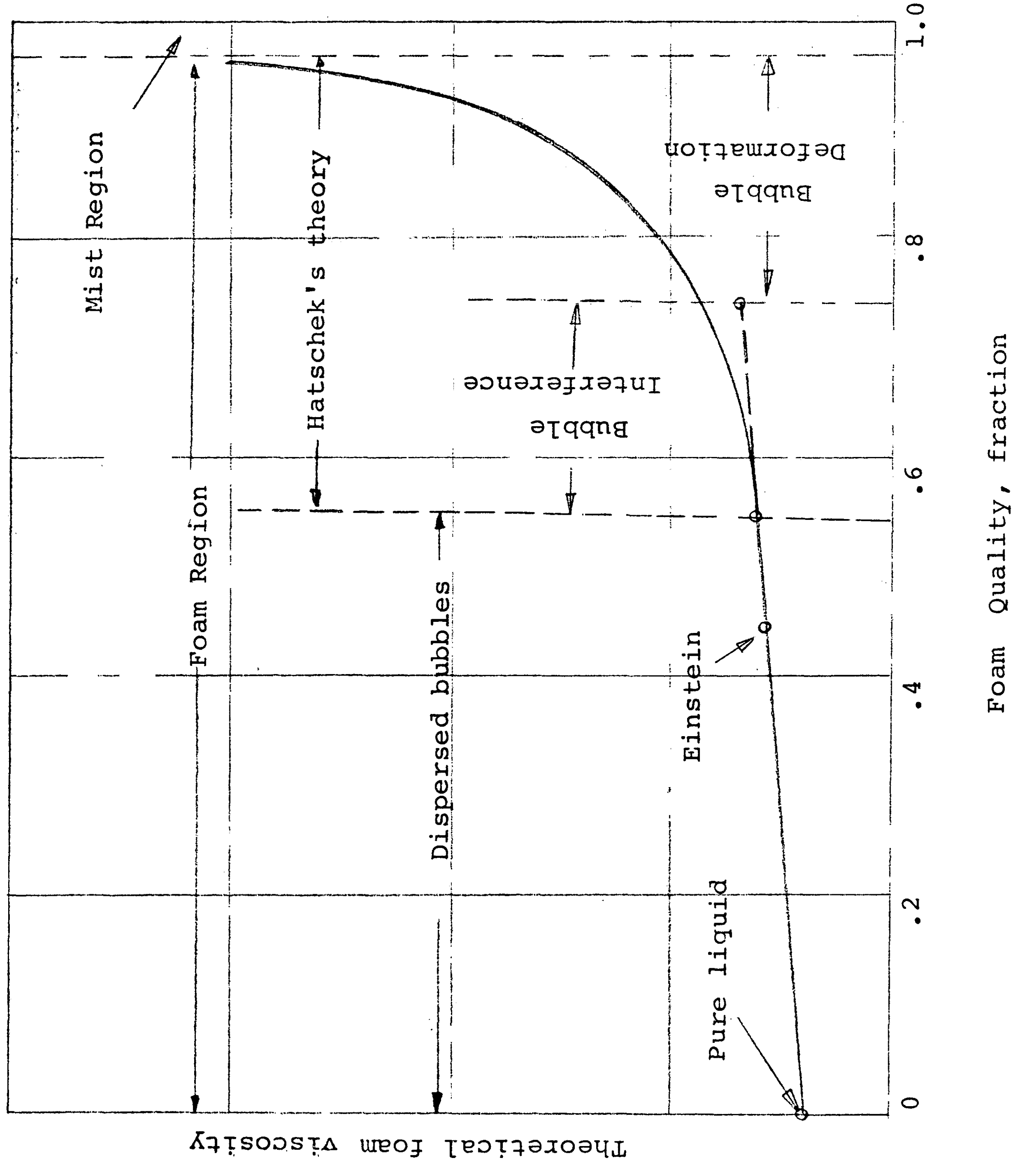
2.2 Foam Displacement in Porous Media

The use of foam as a displacing phase and its flow behavior have been the subject of several investigations. It should be stressed that all the works done in previous studies used water-foam.

2.2.1 Foam as a Displacing Phase. The use of foam as a displacing phase in a porous medium was first reported by Fried[9] He used water-foams to displace oil from consolidated and unconsolidated cores and studied the factors affecting oil and water recovery. Later, Holm[10] and Raza[15] also studied water-foam displacement in porous media. All these investigators found that the permeability of the reservoir rock to a displacing liquid

Figure 1

Theoretical Foam Viscosity 17



or gas was decreased, thus, the mobility ratio and the conformance of the flood were improved.

Bernard[6] and Minssieux[13] tested water-foam displacements in core samples and found that displacement with internally generated foams was more efficient than simple gas drive but less efficient than waterflood. Bernard also reported that oil recovery by foams at gas breakthrough was three times that recovered by a gas drive. Minssieux studied the effect of foam quality on oil recovery by using a foamed-water system to generate the foam. He found that by varying the quality of the foam entering the core, the oil recoveries varied from 25% for gas drives to 65% for straight water drive; thus, he concluded the recovery of oil in place increased as the quality of the foam decreased. Minssieux also reported higher oil recoveries from a core with 130 md. than from a core of 2200 md.

In an externally generated foam flood, Fried[9] reduced oil saturations from 55% to 14% in a 5 darcies sandpack. He also found that this reduction was a direct function of the viscosity of oil originally in place, and that the success of the foam drive process was due primarily to the stability of the foam in the porous media.

2.2.2 <u>Foam Flow Behavior</u>. Several foam-drive mechanisms have been discussed in literature. Holm[10] has summarized these flow mechanisms which are stated as follows:

1) A small portion of gas flows as a free phase following Darcy's law, while a large portion is trapped in the porous medium[11]
2) The foam structure moves as a body; the rate of advance of gas flow is the same as the rate of liquid flow.[9,12]
3) Gas flows as a discontinuous phase by breaking and reforming films, while the liquid flows as a free phase.[5]
4) A portion of the liquid and gas moves as a foam body, while the excess of surfactant solution moves as a free phase.

Fried[9] considered the flow of foam as a plug type and non-Newtonian, and observed the subdividing trend of foam bubbles as entering the core and passing through the constrictions of the flow path. He observed that as foam is injected, an oil bank builds up; the oil recovery was then controlled by (1) flow in previously unaffected pores, (2) high viscosity of the displacing phase, and (3) high pressure gradient at the flood front. Other factors affecting oil recovery appeared to be: (1) the radial movement causing thinning of the film, (2) collapse of the bubbles, and (3) adsorption of the surface-active agent onto the sand. He also observed that some regeneration of foam is required; this regeneration occurs when the foam causes the displacing phase to flow through previously unaffected channels and bubble through the coalesced solution.

2.3 Statement of the Problem

The purpose of the present research is to investigate the recovery effectiveness of foam displacements using a solution of oil and surfactant (oil-foams) rather than an aqueous solution (water-foam). Both internally and externally generated oil-foams are used to displace oil from two consolidated cores under a test pressure gradient of approximately 100 psi/ft. Oil recoveries from these tests are compared to show the effectiveness of oil-foam displacement.

3. EXPERIMENTAL

The following sections describe the equipment and materials, test preparations and test procedure employed in this laboratory study.

3.1 Equipment and Materials

A schematic diagram of the apparatus used in the experiments is shown in Figure 2. Since corrosive liquids such as salt water and high pressures were involved, all the equipment was built of high grade stainless steel.

Berea sandstone cores were provided by Cleveland Quarries, Ohio. The core dimensions were 60.96 and 60.82 cm. long, and 5.04 and 5.05 cm. diameter, respectively.

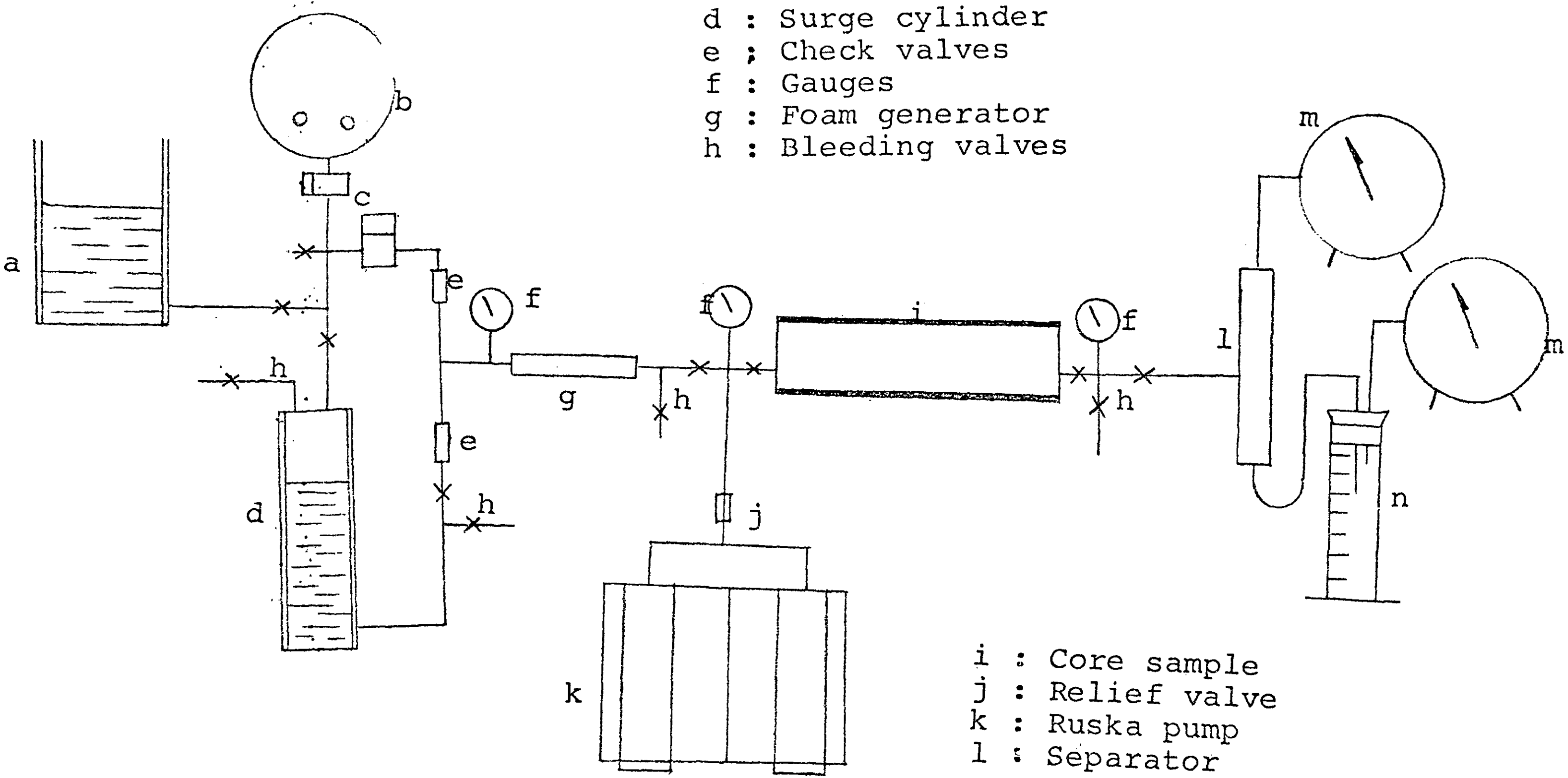
A ruska proportioning pump with two displacing cylinders was used to inject the water and other liquids during tests and to saturate and clean the core during test preparation.

As shown in Figure 2, a closed system was used to carry out the displacements. The system consisted of a high pressure nitrogen bottle used as a source of driving force, a surge cylinder for injecting gas or liquid, and a back pressure regulator for controlling the rate of gas and liquid flow through the foam generator. Bleeding valves, check valves and gauges were also used to provide safety and insure accurate measurements. The surge cylinder

Figure 2

Schematic Diagram of Test Apparatus

a : Reservoir
b : Nitrogen bottle
c : Pressure regulators
d : Surge cylinder
e ; Check valves
f : Gauges
g : Foam generator
h : Bleeding valves



i : Core sample
j : Relief valve
k : Ruska pump
l : Separator
m : Wet Test Meters
n : Graduate cylinder

provided a constant injection pressure and injection rate to control the quality of the generated foams.

The brine used in the saturation process consisted of a 1% sodium chloride in distilled water, having a viscosity of .59 cp. and a specific gravity of 1.02. Kerosine of 33.0° API at 60°F and 1.11 cp. was used to saturate the core to get the connate water saturation and also as solvent to prepare the surfactant solution to generate the foam.

The surface-active agent consisted of a commercial surfactant called FLUORAD or FC-432*, sold as a 25% solution in Heptane; this compound has the ability to sustain a foam on various organic liquids. Tables 3 and 4 present some of its most important properties and surface tensions of its solutions.

3.2 Test Preparation

3.2.1 Core Preparation.

To encase the core into the pup joint, it was first coated with a thin layer of two premixed epoxy resins and then centered in the pipe. After plugging one end, the annulus was filled with a melted alloy. Two holes of 1/8-in. diameter were drilled on both ends to reach the core.

The Klinkenberg air permeability was found to be 22 and 81 millidarcies in cores 1 and 2, respectively;

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* A trademark of Union Carbide Company

Table 1

Data for Klinkenberg Air Permeability Determinations
(Core 1 and 2)

Core 2				Core 1			
$1/\bar{P}$ (atm^{-1})	ka (md)	Q_{avg}/A (cm/sec.)	$\Delta P/L$ (atm/cm)	Q_{avg}/A (cm/sec.)	$\Delta P/L$ (atm/cm)	ka (md)	$1/\bar{P}$ (atm^{-1})
.69	104.2	8.40×10^{-2}	14.34×10^{-3}	5.50×10^{-2}	13.90×10^{-3}	49.3	.70
.71	109.2	8.09	13.20	4.30	12.10	46.2	.73
.73	111.6	7.54	12.02	3.90	10.95	47.6	.75
.74	102.6	6.69	11.26	3.60	9.80	50.3	.77
.77	109.8	6.17	10.00	3.10	8.75	49.8	.79
.78	113.8	5.67	8.87	2.60	7.70	48.8	.81
.81	114.1	4.97	7.75	2.40	6.55	54.1	.83
.83	114.8	4.32	6.70	2.00	5.45	56.2	.86
.88	114.0	2.81	4.39	1.40	4.38	52.6	.88

$K_{Klinkenberg}$ = 81 md.

$K_{Klinkenberg}$ = 22 md.

$$ka = 17.8\ \frac{Q_{avg}/A}{\Delta P/L}$$

Air viscosity (μa) = .0178 cp

See Figure 3 for Klinkenberg permeability calculations

Figure 3

Plot for Klinkenberg Air Permeability Determination

Core 1 and 2

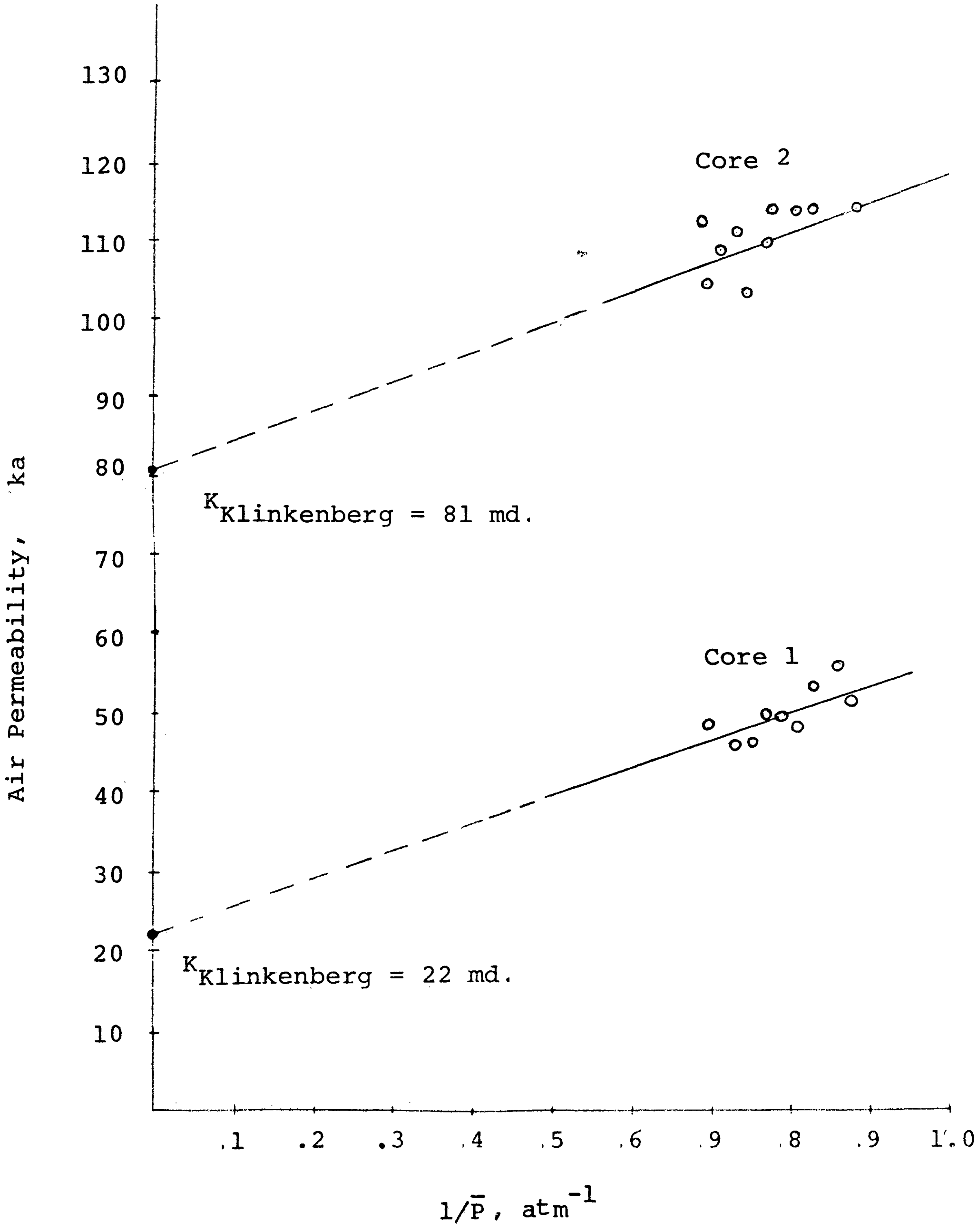


Table 2

Data for Average Specific Oil and Water Permeabilities Determinations
(Core 1 and 2)

Core 2							Core 1				
Q/A (cm/sec)	ΔP/L (asm/cm) (100%Sw)	Kw (md)	ΔP/L (atm/cm) (Sor)	kw (md)	ΔP/L (atm/cm) (Swi)	ko (md)	Q/A (cm/sec)	ΔP/L (atm/cm) (100%Sw)	kw md	ΔP/L (atm/cm) (Swi)	ko (md)
6.29×10^{-3}	.758	4.89	.62	5.98	1.200	5.81	6.1×10^{-3}	.91	3.95		
5.34	.560	5.62	.57	5.53	1.120	5.29	5.26	.80	3.88		
4.45	.464	5.66	.40	6.56	.850	5.81	4.38	.68	3.80		
3.56	.313	6.71	.30	7.00	.640	6.20	3.50	.52	3.97	.991	3.9
2.67	.195	8.08	.22	7.16	.430	6.89	2.63	.43	3.61	781	3.7
2.22	.178	7.36	.18	7.27	.350	7.04	2.19	.37	3.49	714	3.4
1.78	.160	5.56	.14	7.50	.260	7.60	1.75	.32	3.23	.655	2.9
1.56			.12	7.67	.220	7.87	1.53	.29	3.11		
1.34			.11	7.18	.180	7.77	1.31	.26	2.97		
1.11			.09	7.27	.140	8.80	1.09	.24	2.68		
.89			.07	7.50	.110	8.98	.87	.21	2.44		
.67			.06	6.58	.080	9.29					
.56			.05	6.60	.078	7.97					
.44					.061	8.00					
.39					.056	7.73					
.33					.045	8.14					

w avg = 6.6 md.

*kw avg = 6.5 md

**ko = 7.64 md.

*kw avg = 3.7 md

*ko avg = 3.4 after foam injection

$*kw = 590 \times \frac{Q/A}{\Delta P/L}$ (md) ; $**ko = 1110 \times \frac{Q/A}{\Delta P/L}$ (md)

See Figure 4 for permeability calculations

Figure 4

Plots for Specific Oil and Water Permeability Calculations.

Cores 1 and 2

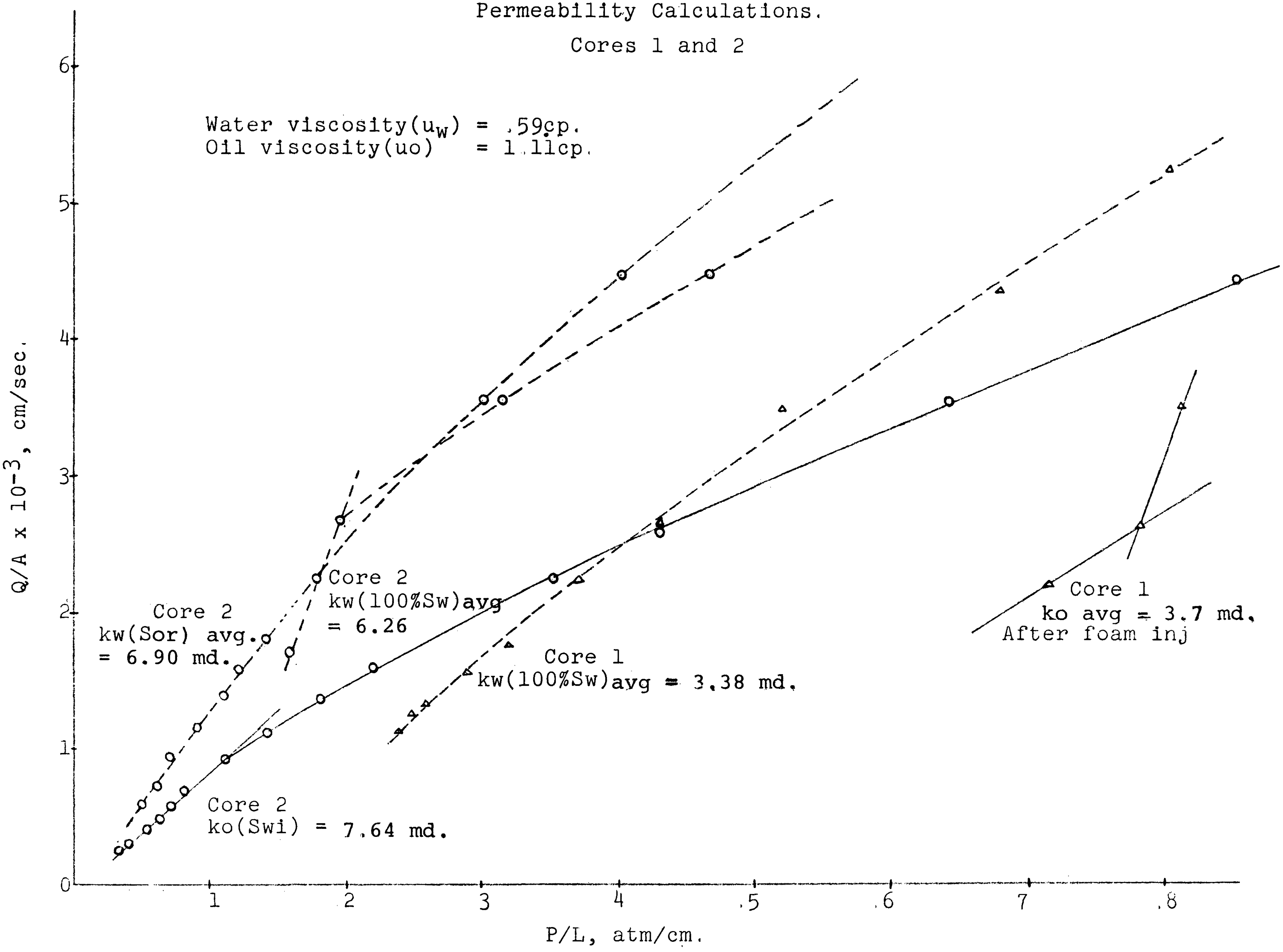


Table 3

Properties of the Surface-Active Agent,

FLUORAD FC-432*

Typical Properties:

Form	25% Active in Heptane
Color	Colorless to Pale Yellow
Viscosity	5.0 cp.
Density	.78 gr/cc. at 25 °C
Refractive Index	1.40

Solubility: (Grams of solute/100 grams of solvent)

Water	<.2	Methyl Ethyl Ketone	.2 -.5
Methyl Alcohol	<.2	1,1,1-Trichloroetane	>20
Dimethylfoamide	<.2	Perchloroethylene	>20
Isopropyl Alcohol	<.2	Toluene	>20
Ethyl Acetate	2 -.5	Benzene	>20
Cellosolve Acetate	.2 -.5	Heptane	>20

*Data from 3M Company

Table 4

Surface Tensions of FC-432 Solutions*

Solvent	Surface Tension, Dynes/cm at 25°C			
	Blank	Conc. of FC-432 Solids		
		.5%	.2%	.05%
Ethyl Acetate	23.1	20.5	20.6	20.6
Cellosolve Acetate	28.1	24.1	24.6	27.9
50/50 Ethyl Alcohol Toluene	23.9	20.3	20.3	20.6
Methyl Ethyl Ketone	23.9	20.0	20.4	20.7
1,1,1-Trichloroetane	25.7	21.4	22.4	22.9
Perchloroethylene	31.6	22.3	22.2	25.4
Toluene	27.7	21.0	22.0	22.3
Benzene	28.1	20.3	21.1	22.0
Heptane	19.7	19.2	19.4	-

*Data from 3M Company

these values were obtained by air injection at low pressures and low injection rates. Table 1 and Figure 3 show the experimental results for air permeability determinations. The pore volume for each core was calculated by weighing the core sample before and after water saturation. Pore volumes determined were 258 and 256 cc. for cores 1 and 2, respectively. The corresponding porosity was 21% for both cores.

To saturate the core with water, vacuum was applied on both sides to evacuate all the air contained in the pore spaces; then, brine was injected at a rate of 7.5 cc/min. About 6 pore volumes of water were passed through the core to a complete saturation under pressures ranging between 500 psi and 2000 psi.

Connate water saturations reached values of 28 and 27% in cores 1 and 2, respectively. To obtain those water saturations, about 24 pore volumes of kerosine were injected.

The average specific permeability to water was found to be 3.4 and 6.3 millidarcies for cores 1 and 2, respectively: kerosine specific permeabilities obtained at the residual water saturation were 3.7 and 7.6 md., respectively. Figure 4 shows results obtained during the displacements used to calculate oil and water permeabilities.

To clean the core after each run, heptane was injected to get rid of all residual surfactant solution, and then liquid propane was further injected to displace the remaining heptane.

To resaturate the core with kerosine, approximately 8 pore volumes were injected from both ends and left overnight to let the residual surfactant solution dissolve in kerosine; the procedure was the same as before.

3.2.2 Foam Generation and Testing. The foam generator consisted of a 17- by 1/8-in. stainless steel pipe filled with sand from 80 to 200 mesh; the larger grain size was placed at the outlet with metal screen and glass wool preventing the migration of sand from the generator. A bleeding valve at the outlet of the foam generator was used to test the foam quality before entering the core.

To generate foam, a solution of .2% surface-active agent in kerosine was injected through the foam generator at a given rate; the volume of gas needed to make up the foam was controlled by means of a Grove small volume regulator.

Figure 5 shows the results of the surfactant concentration effect on foam generation; it was found that a concentration of .2% kerosine was the optimum concentration to generate oil-foam in 100 ml. sample. This method was suggested by Kolb.[11] In this method 100 ml.

of solution of different concentration was allowed to free-fall into a graduate cylinder from a given distance. The initial volume of foam was measured.

Figure 6 presents the surface tension of solutions vs. the surfactant concentration. The surface tensions were measured with a Du Nouy ring type tensiometer at 70°F. Using these correlations, the concentration of surfactant in the effluent was determined.

As previously described, foam quality was tested at atmospheric pressure before entering the core and then corrected to the injection conditions. Since foam quality is dependent on pressure, the quality at injection pressure Pi, being tested at atmospheric pressure Pa, is given by:[12]

$$\Gamma_i = \frac{1}{1+\frac{Pi}{Pa}\left[\frac{1}{\Gamma_a} - 1\right]}$$

where, Γ_i = Foam quality at injection pressure

Γ_a = Foam quality at atmospheric pressure

Foam Quality is defined as the ratio of the volume of the gas phase to the volume of the foam generated.

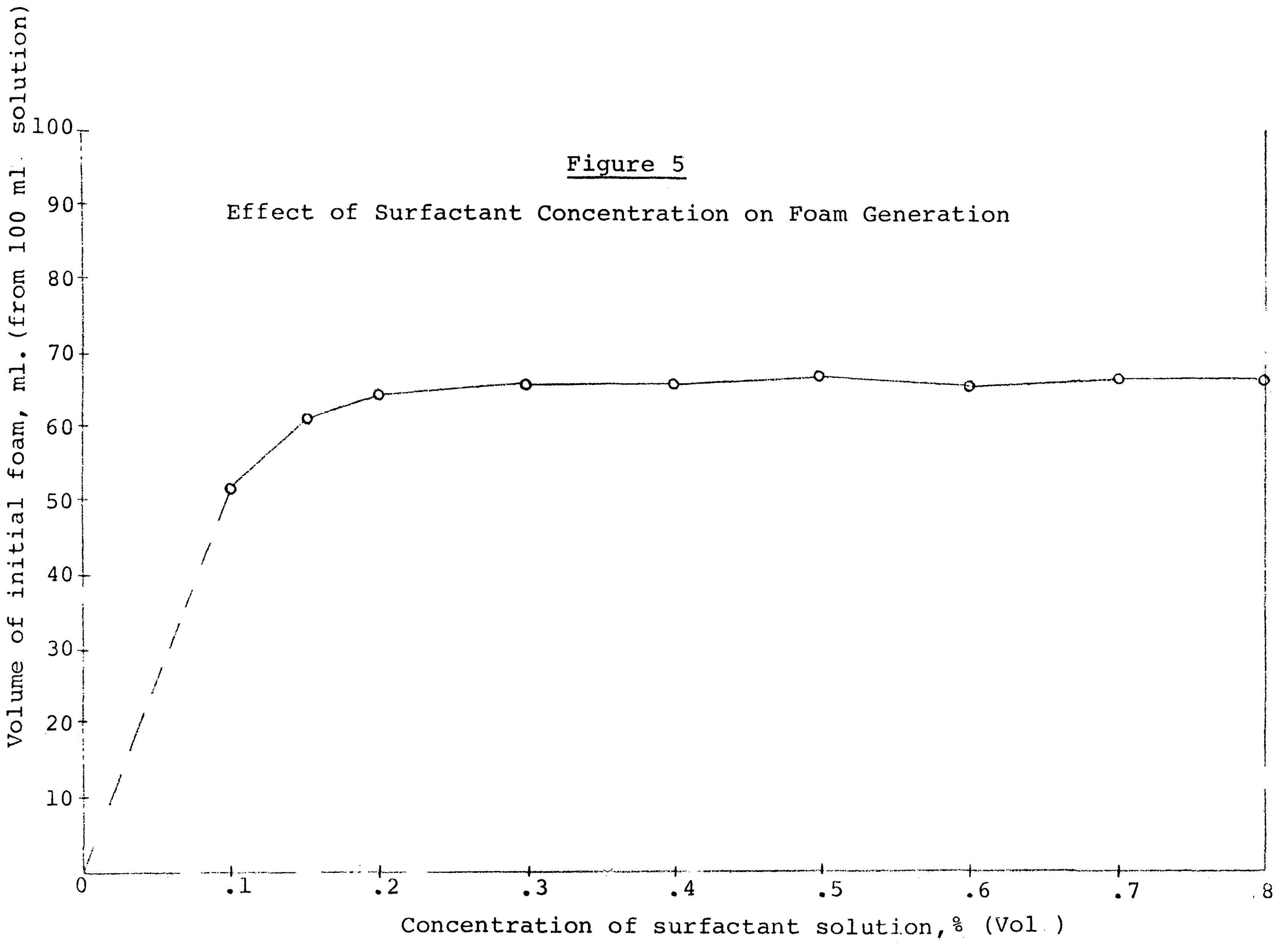
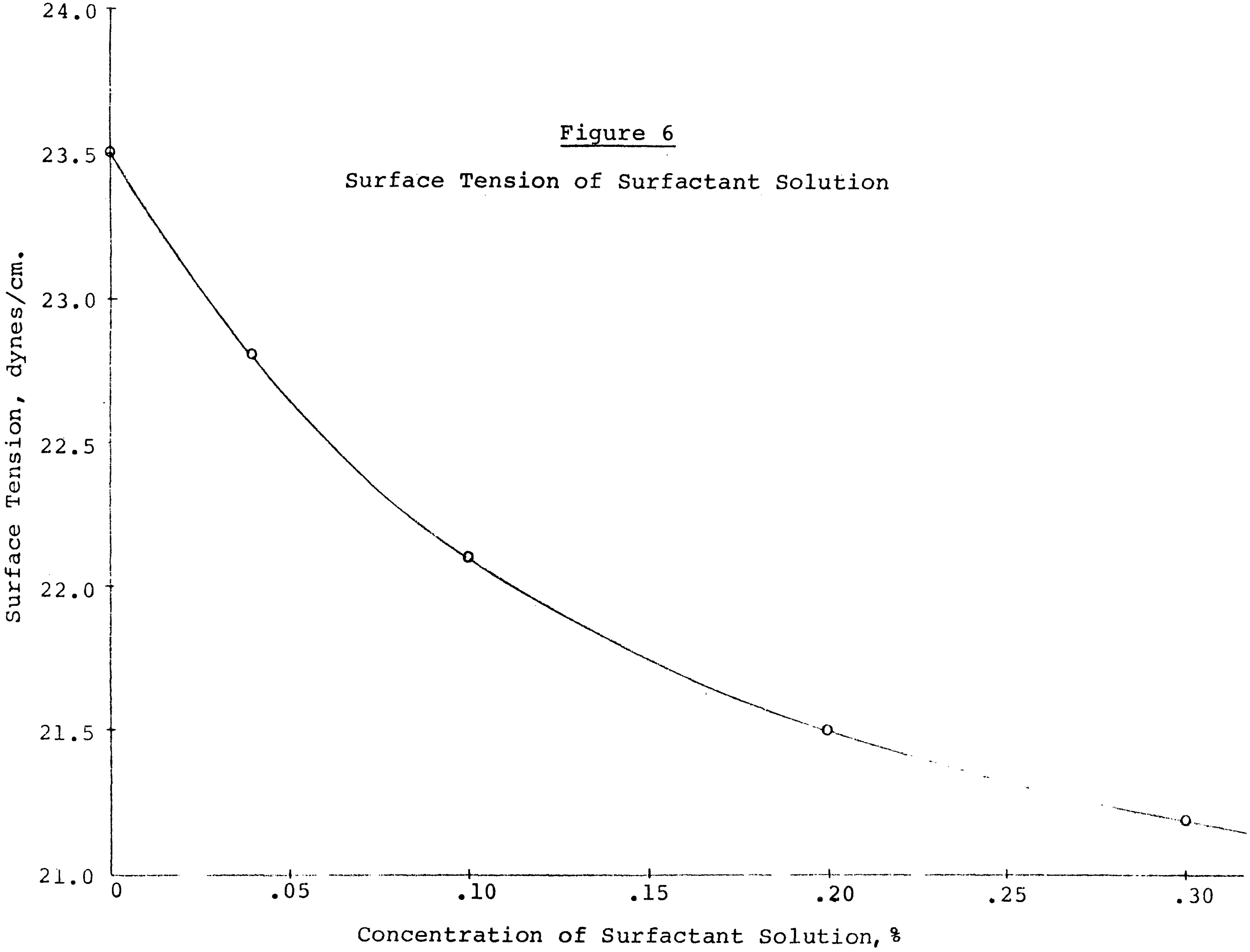


Figure 5

Effect of Surfactant Concentration on Foam Generation

Figure 6

Surface Tension of Surfactant Solution



3.3 Test Procedure

A total of six tests were performed. The tests were run at high injection pressures ranging from 715 to 875 psig. The conventional waterflooding run at 1150 psig served as a base for comparison of oil recovery obtained on the displacement tests.

3.3.1 Conventional Waterflooding. The first experiment was a conventional waterflooding which used core 2

Brine water, 1% NaCR was injected under a stabilized injection pressure of 1150 psi (See Figure 7) The initial saturation conditions of the core sample were 73% of oil saturation and 27% of water saturation. The test was run until 3.51 pore volumes of water were injected. Table 5 shows the displacement data indicating that 54% of the original oil in place was recovered (39.4% PV).

Figure 4 shows the data for average permeability calculations for the water phase. A value of 6.7md was recorded being lowered from 6.3md, which was the permeability for 100% water saturation. Oil and water saturation obtained after the water displacement were 34 and 66% respectively.

3.3.2 Tertiary Recovery with Externally Generated Oil-Foam. The core after conventional waterflooding was used for secondary recovery tests using externally generated oil-foam. The amount of gas and liquid being injected through the foam generator was regulated to obtain a given foam quality. The foam quality was tested at .95. Table 6 shows the displacement data.

At about 24 minutes after starting the test (See Figure 8 for more details), oil appeared at the production end and the injection pressure reached a stabilized value of 850 psi; at this point approximately .028 pore volumes of net oil had been produced. Gas breakthrough occurred under stabilized conditions when .10 pore volumes of net oil had been produced. Gas breakthrough occurred under stabilized conditions when .10 pore volumes of net oil had been produced. The experiment was run for about 150 minutes until the oil and gas production rate stabilized. Figure 14 shows the effluent surfactant concentration. Net oil recovery was found to be .157 PV.

3.3.3 Secondary Recovery with Externally Generated Oil-Foam. The third type of test consisted of a secondary oil recovery displacement with oil-foam also generated outside of the core. Core 1 was used in which foam quality was tested before injected to the core. Initial oil and water saturation of the core were 72 and 28%, respectively. The injection pressure was maintained almost constant at 775 psig, and a stabilized pressure drop of 85 psi across the core was observed after approximately 10 minutes of foam injection (See Figure 14) The displacement was continued until approximately .55 pore volumes of oil were produced at the outlet, and 20,200 cc of gas were measured at the wet gas meter. Gas breakthrough occurred 5 minutes after starting the injection of surfactant solution and gas; at this point approximately .14 pore volumes of total oil had been produced; at this point a constant pressure drop began to stabilize. Figure 9 shows the displacement performance, and Figure 14 presents the surfactant concentration of the produced oil. Table 7 presents the displacement data, showing a total net oil recovery of .238 PV.

3.3.4 Internally Generated Oil-Foam. To study the displacement performance of internally generated oil-foam, and flow behavior in the porous medium three experiments were run in both cores. The tests consisted of the injection of three different slug sizes of surfactant solution into the core, followed by nitrogen injection at a given pressure. The injection pressures were maintained constant ranging from 715 to 800 psig. The pressure drop of the injection of three different slug sizes of surfactant solution into the core, followed by nitrogen injected at a given pressure. The injection pressures were maintained at constant values ranging between 715 and 800 psi. The pressure drop across the core was observed to get a stabilized value right after gas breakthrough. Gas injection was maintained until a constant gas production was recorded and no oil was produced. Oil and gas effluents were collected in graduate cylinders connected to gas meters; these data were utilized to compute fractional flow, surfactant concentration and oil recovery. Figures 10, 11 and 12, and Tables 8, 9, and 10 present the data and displacement performance obtained from the experiments. Figures 16, 17 and 18 show fractional flow, pressure behavior and net oil recoveries, respectively.

4. RESULTS

Following is a summary of the experimental results obtained from the oil displacements, corresponding to the conventional waterflooding and the externally and internally generated oil-foams tests.

4.1 Conventional Waterflooding

Table 5: Summary of Oil Displacement Data, Including Fractional Flow - Core 2.

Figure 7: Production Performance - Oil Recovery vs. Cumulative Water Injected.

Figure 13: Water Fractional Flow vs. Water Saturation.

4.2 Externally Generated Oil-Foam

Table 6: Displacement Data for Tertiary Recovery in Core 2.

Figure 8: Performance of the Tertiary Recovery Test. Oil and Gas Production, and Differential Pressure vs. Time.

Table 7: Displacement Data for Secondary Recovery in Core 1.

Figure 9: Performance of the Secondary Recovery Test. Oil and Gas Production, and Differential Pressure vs. Time.

Figure 17: Pressure Behavior vs. Time

Figure 18: Net Oil Recovery vs. Cumulative Gas Injected.

Figure 14: Surfactant Concentration vs. Cumulative Oil Recovery for Both Tertiary and Secondary Recovery Tests.

4.3 Internally Generated Oil-Foam

Table 8: Displacement Data for 11% PV Slug Size - Core 2.

Figure 10: Displacement Performance for 11% PV Slug Size - Oil and Gas Production and Differential Pressure vs. Time.

Table 8: Displacement Data for 20% PV Slug Size.

Figure 11: Displacement Performance for 20% PV Slug Size - Oil and Gas Production, and Differential Pressure vs. Time.

Table 9: Displacement Data for 20% PV Slug Size.

Figure 12: Displacement Performance for 30% PV Slug Size - Oil and Gas Production, and Differential Pressure vs. Time.

Figure 15: Gas - Oil Ratios vs. Cumulative Oil Production.

Figure 14: Surfactant Concentration vs. Cumulative Oil Produced.

Figure 16: Fractional Flow vs. Gas Saturation.

Table 5

Displacement Data of Conventional Waterflooding, Core 2 (PV = 256cc)

Differential Pressure (psi)	Time (min)	Total Production Water (ml.)	Total Production Oil (ml.)	Oil Recovery (PV)	Water Injected (PV)	f_w	$\bar{S}_w$
900	.70		5	.02	.02		
1075	.80		10	.04	.04		
1175	2.70		24	.09	.09		
1150	3.50		30	.12	.12		
1025	6.00		44	.17	.17		
1150	8.00		64	.25	.25		
1150	10.70		84	.32	.32		
1150	12.30	Trace	92	.35	.35		
1150	14.00	7	93	.363	.38	.875	.584
1150	14.60	10	93	.363	.40		
1150	16.50	27	93	.363	.47		
1150	18.50	37	93	.363	.50	.940	.617
1150	20.0	47	93	.363	.55		
1150	34.00	152	98	.384	.97	.9545	.6288
1150	67.00	401	99	.387	1.95	.9990	.6568
1150	107.00	799	101	.394	3.51	.9995	.6622

Table 6

Displacement Data for Tertiary Recovery with Externally Generated Oil-Foam, +
Core 2 (PV = 256 cc)

Differential Pressure (psi)	Time (min)	Total Water Production (PV)	Total Oil Production (PV)	*Total Gas Production (PV)	Effluent Concentration of Surfactant (%)	Net Oil Recovery (PV)
810	5					
820	7	.031				
850	13	.058				
865	15	.070				
870	20	.082				
875	23	.089				
850	30	.105	.007			
850	50	.152	.042		.068	.028
850	66	.167	.144		.085	.086
850	70	.175	.183	Trace	.120	.102
850	87	.183	.230	.17	.135	.117
850	90	.191	.316	.19	.160	.134
850	100	.207	.402	.31	.185	.141
850	120	.218	.578	.48	.190	.149
850	150	.243	.867	.78	.195	.157

* At atmospheric pressure

\+ Foam quality=.95

Table 7

Displacement Data for Secondary Recovery with Externally Generated Oil-Foam; +

Core 1 (PV = 258 cc)

Injection Pressure (psig)	Differential Pressure (psi)	Time (min.)	Total Oil Production (PV)	Total Gas Prod.* (PV)	Effluent Concentration of Surfactant (%)	fg at Outlet Pressure	Gas** Injected (PV)	Net Oil Recovery (PV)
725	175	2.5	.058		.004			.054
740	170	4						
750	150	5	.1162		.011			.091
	140	6		Trace				
	95	7						
775	75	8	.1589	.76	.025	.2712	.1406	.129
775	85	10						
760	95	16	.1937	4.5	.030	.6605	.2300	.1586
775	85	30	.2286	9.6	.070	.7595	.3300	.1812
775	85	45	.2790	17.6	.120	.7650	.4716	.2012
775	85	70	.3410	31.0	.140	.8217	.6962	.2198
775	85	82	.3798	38.7	.160	.8087	.8222	.2275
775	85	122	.4689	58.1	.180	.8230	1.1290	.2364
775	85	160	.5581	78.2	.195	.8270	1.4400	.2386

* At atmospheric pressure

** At injection pressure

\+ Foam quality = .995

Table 8

Displacement Data for Secondary Recovery with Internally Generated Oil-Foam,

11% PV Slug Size; Core 2 (PV = 256 cc)

Injection Pressure (psig)	Differential Pressure (psi)	Time (min.)	Total Oil Production (PV)	Total Gas Production* (PV)	Effluent Concentration of Surfactant %	GOR**	fg ***	Gas*** Injected (PV)	Net Oil Recovery (PV)	$\overline{S_g}$.
720	70	3								
720	60	4	.0585							.0585
	40	5								
720	30	6	.0976	Showed	.001				.0971	.098
720	50	10	.1328	.88	.002	41	.431	.1483	.1319	.133
710	20	12	.1406	1.23		54	.500	.1623		.141
715	25	17	.1601	2.59		90	.623	.2060		.160
715	25	22	.1720	3.86	.003	110	.760	.2410	.1704	.172
715	25	30	.1953	8.58	.003	250	.822	.3472	.1935	.200
715	25	42	.2109	13.26	.003	420	.886	.4460	.2166	.211
715	25	61	.2500	31.63	.004	1,100	.948	.8100	.2472	.250
715	25	13 hrs	.3203	303.00	.006	50,000	.998	5.6860	.3154	.320

* At atmospheric pressure

**Read from smoothed plot

*** At core mean pressure

Table 9

Displacement Data for Secondary Recovery with Internally Generated Oil-Foam,

20% PV Slug Size; Core 1 (PV = 258 cc)

Injection Pressure (psig)	Differential Pressure (psi)	Time (min.)	Total Oil Production (PV)	Total Gas Production* (PV)	Effluent Concentration of Surfactant (%)	GOR**	f_g ***	Gas*** Injected (PV)	Net Oil Recovery (PV)	$\overline{S_g}$.
800	180	3								
800	210	4	.0310					.0310		.031
800	175	5	.0380					.0380		.038
800	160	6	.0542					.0542		.054
800	150	9	.0930		.0100			.0930	.0883	.093
800	150	11	.1317	Trace	.0075	0		.1320	.1256	.132
800	150	22	.1667	1.02	.0050	30	.371	.1947	.1596	.167
800	150	39	.2054	3.17	.0100	60	.579	.2602	.1960	.205
800	150	53	.2519	6.97	.0180	150	.746	.3723	.2384	.252
800	150	73	.2868	15.20	.0180	700	.932	.5494	.2701	.287
800	150	90	.3023	29.26	.0180	1,500	.975	.8078	.2842	.302
800	150	5 hrs.	.3256	342.60	.0180	30,000	.998	6.2450	.3054	.326

* At atmospheric pressure

** Read from smooth plot

*** At core mean pressure

Table 10

Displacement Data for Secondary Recovery with Internally Generated Oil-Foam,

30% PV Slug Size; Core 2 (PV = 256 cc)

Injection Pressure (psig)	Differential Pressure (psi)	Time (min.)	Total Oil Production (PV)	Total Gas Production* (PV)	Effluent Concentration of Surfactant (%)	GOR**	fg ***	Gas*** Injected (PV)	Net Oil Recovery (PV)	$\overline{S}_g$
800	200	2	.0585		.0050				.0571	.058
800	40	4	.0976		.0180				.0927	.097
800	45	8	.1015	Trace						.102
800	45	11	.1093	1.14		10	.376	.1277		.109
800	45	15	.1250	1.44	.0180	28	.458	.1482	.1208	.125
800	45	17	.1367	1.83	.0180	35	.504	.1667	.1315	.137
800	45	20	.1562	2.77	.0180	55	.575	.2017	.1493	.156
800	45	24	.1757	4.68	.0180	90	.650	.2526	.1671	.176
800	45	30	.2109	8.20	.0270	180	.752	.3456	.1975	.211
800	45	35	.2382	14.80	.0310	340	.852	.4815	.2205	.238
800	45	38	.2460	19.53	.0320	400	.871	.5670	.2271	.246
800	45	50	.2929	41.70	.0400	2,000	.971	.9783	.2581	.293
800	45	5 hrs.	.3242	246.50	.0400	25,000	.995	4.3760	.2830	.324

* At atmospheric pressure

** Read from smoothed plot

*** At core mean pressure

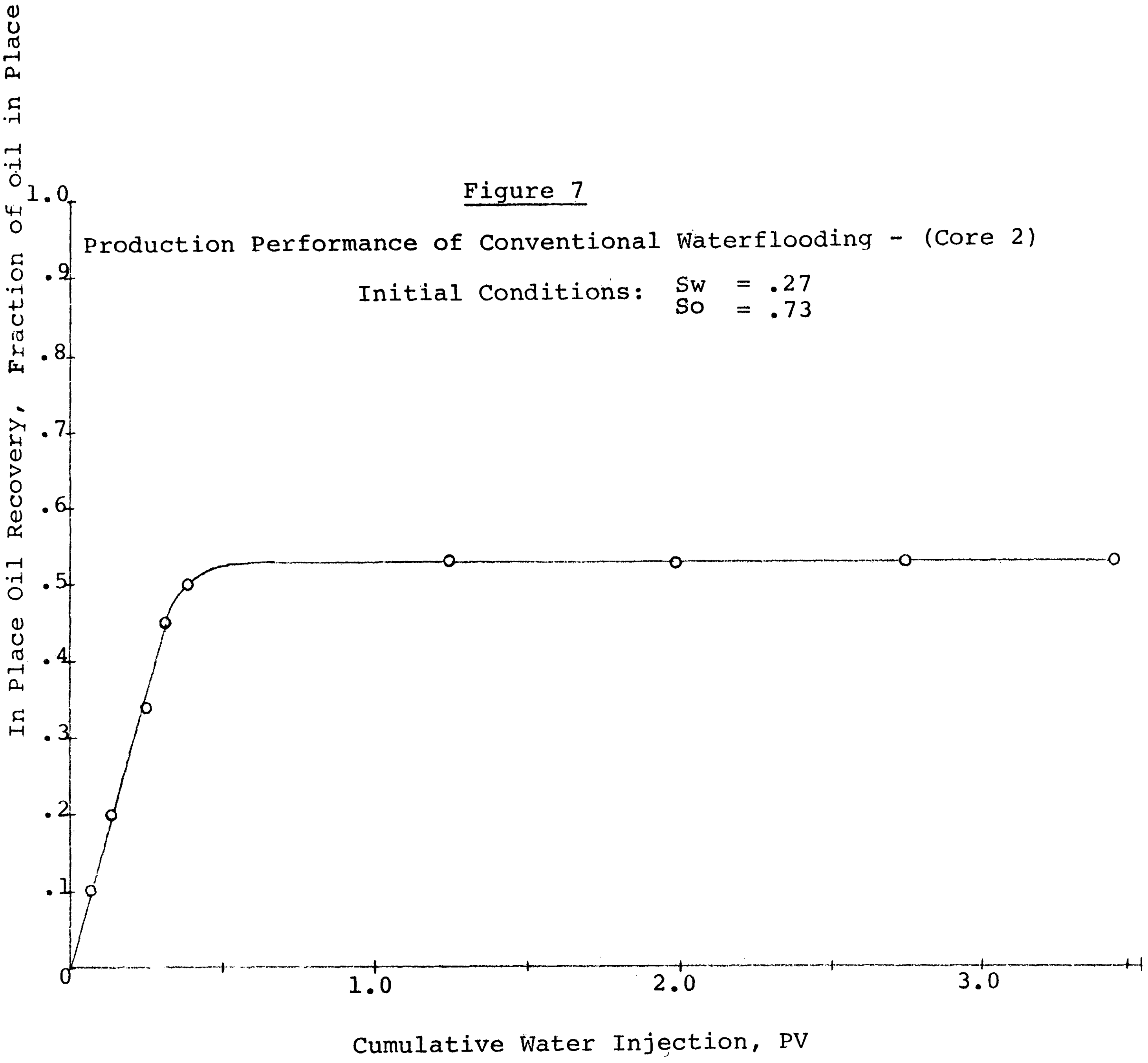


Figure 7

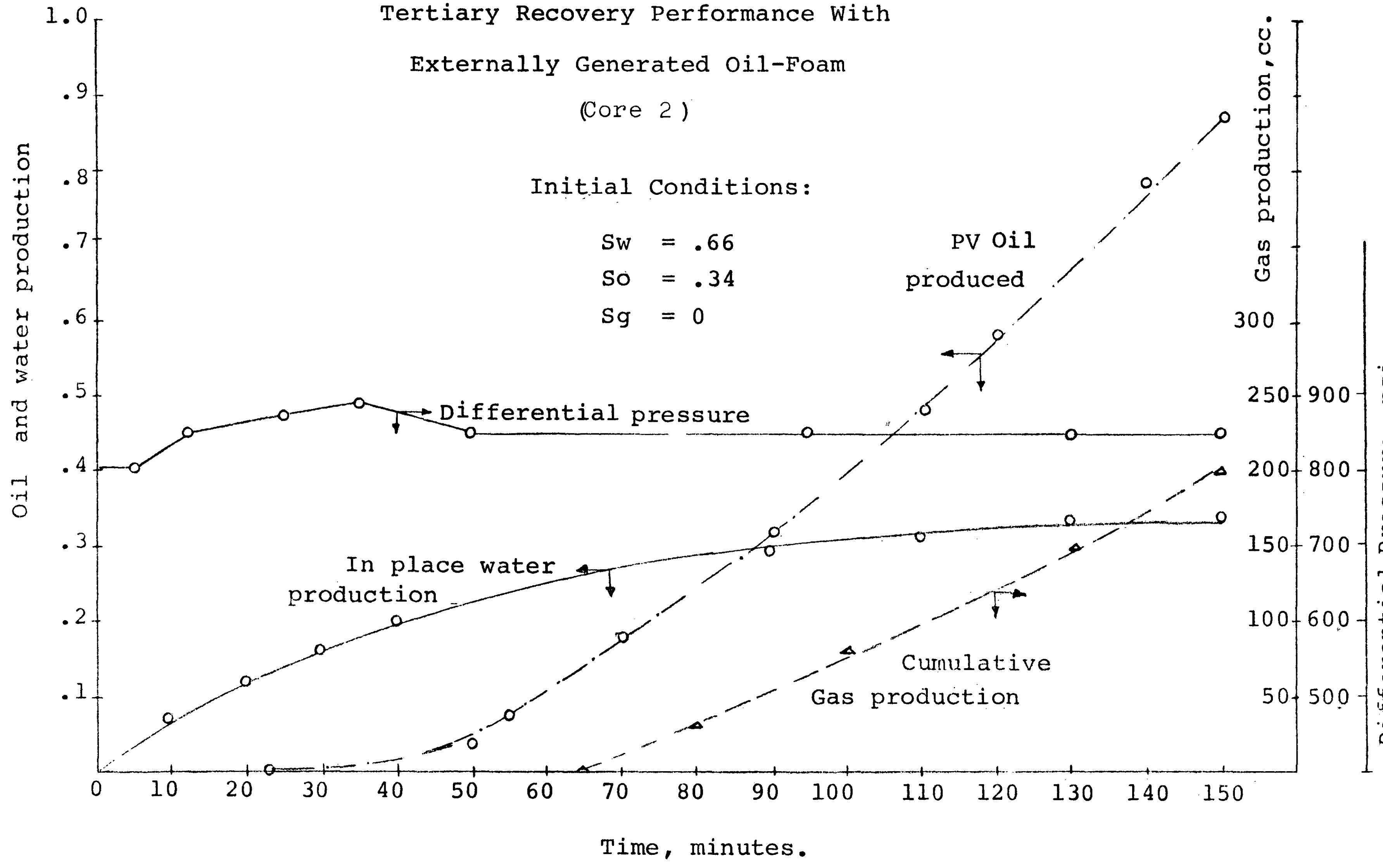
Production Performance of Conventional Waterflooding - (Core 2)

Initial Conditions: Sw = .27
So = .73

Figure 8

Tertiary Recovery Performance With Externally Generated Oil-Foam

(Core 2)



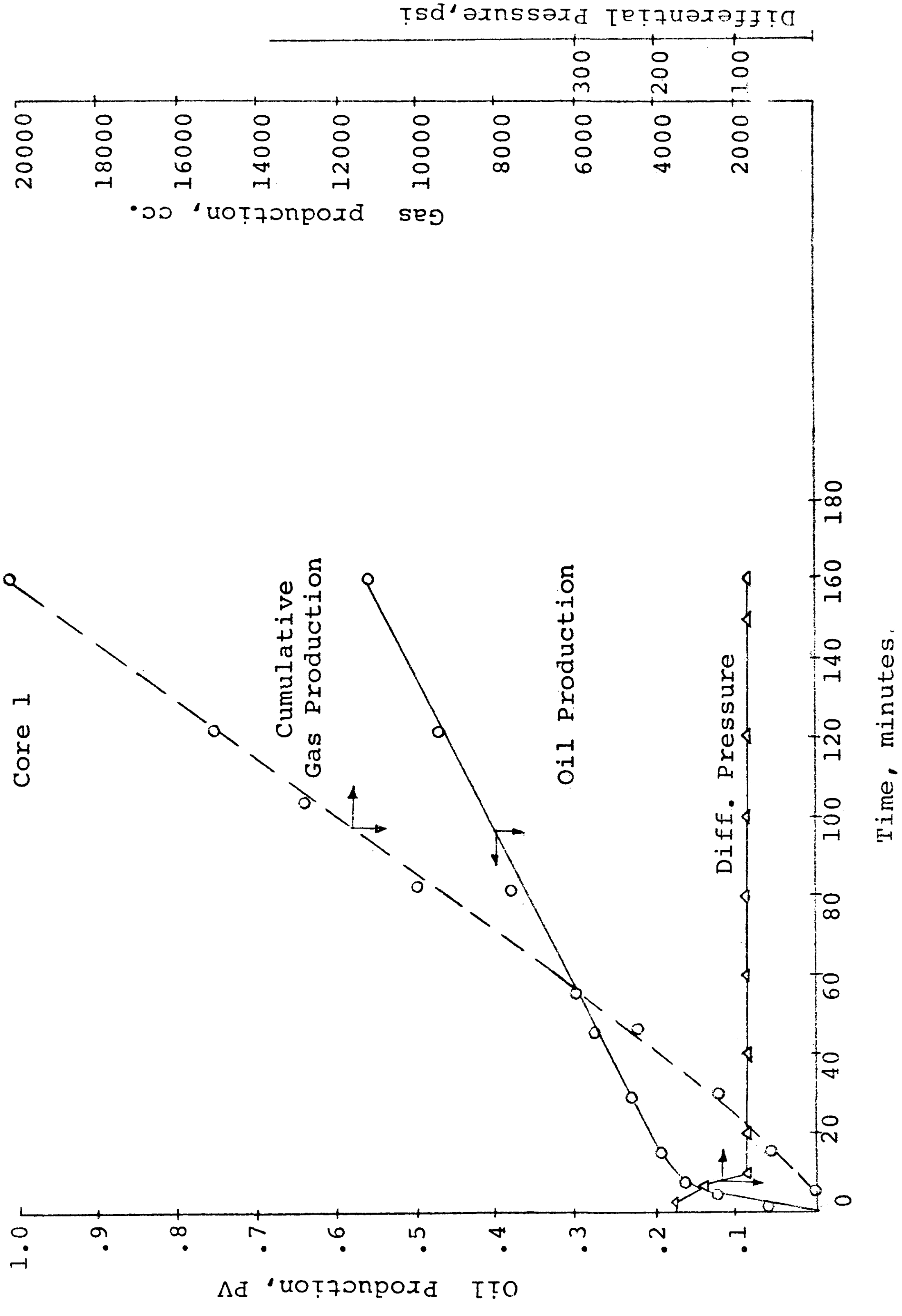


Figure 9

Secondary Recovery Performance

With Externally Generated Oil-Foam

Core 1

Figure 10

Displacement Performance with Internally Generated Oil-Foam

(11% PV Slug Size -Core 2)

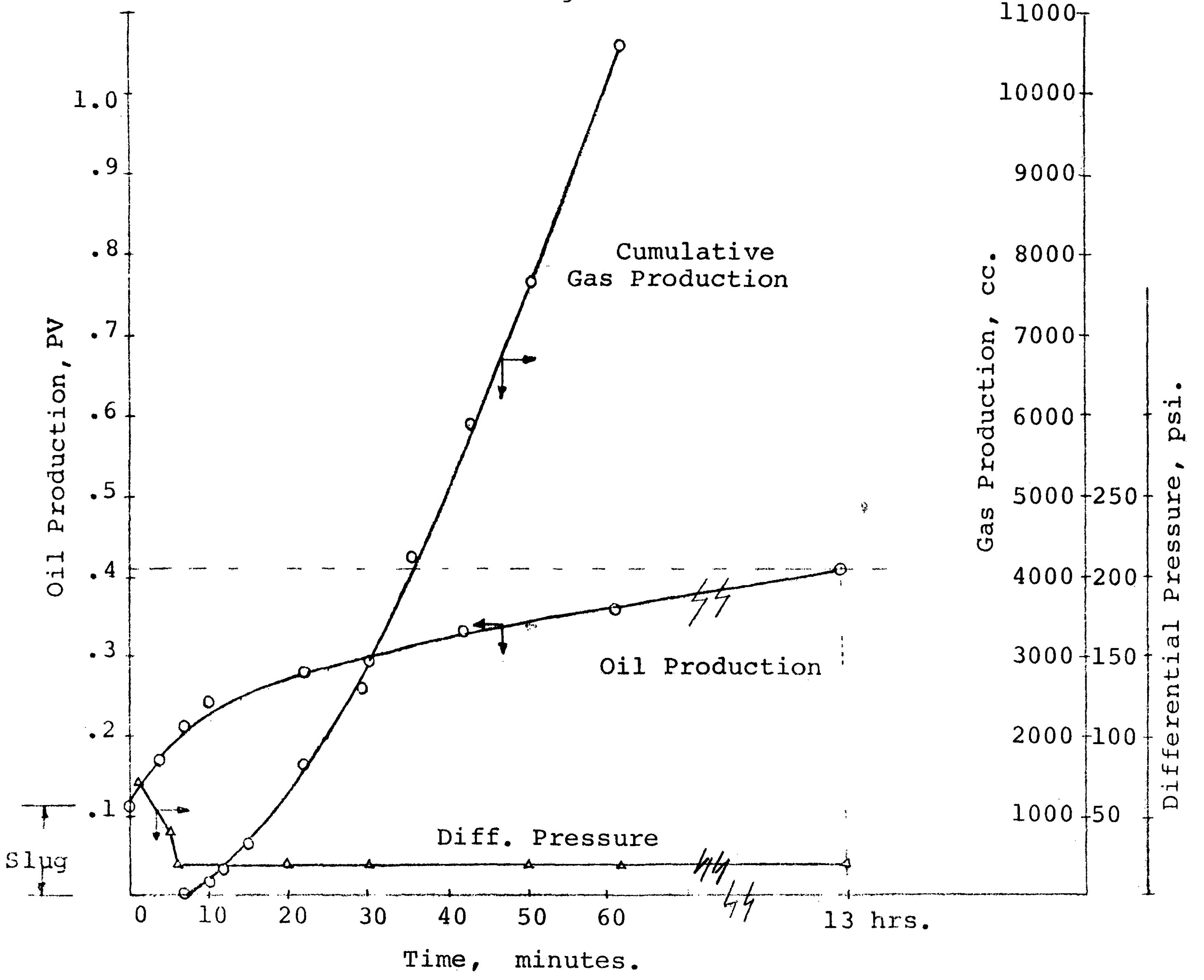


Figure 11

Displacement Performance with Internally Generated Oil-Foam

(20% PV Slug Size -Core 1)

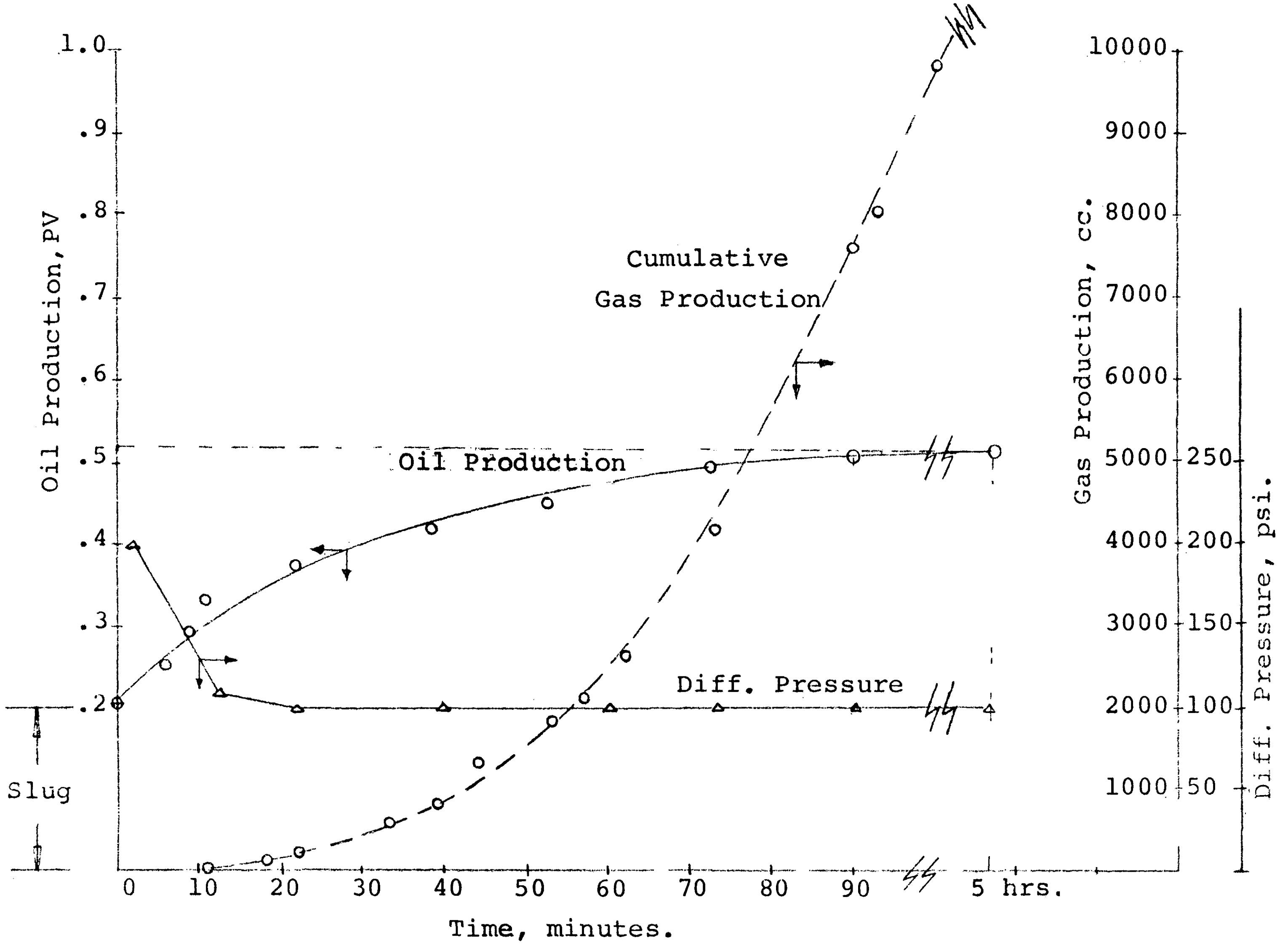
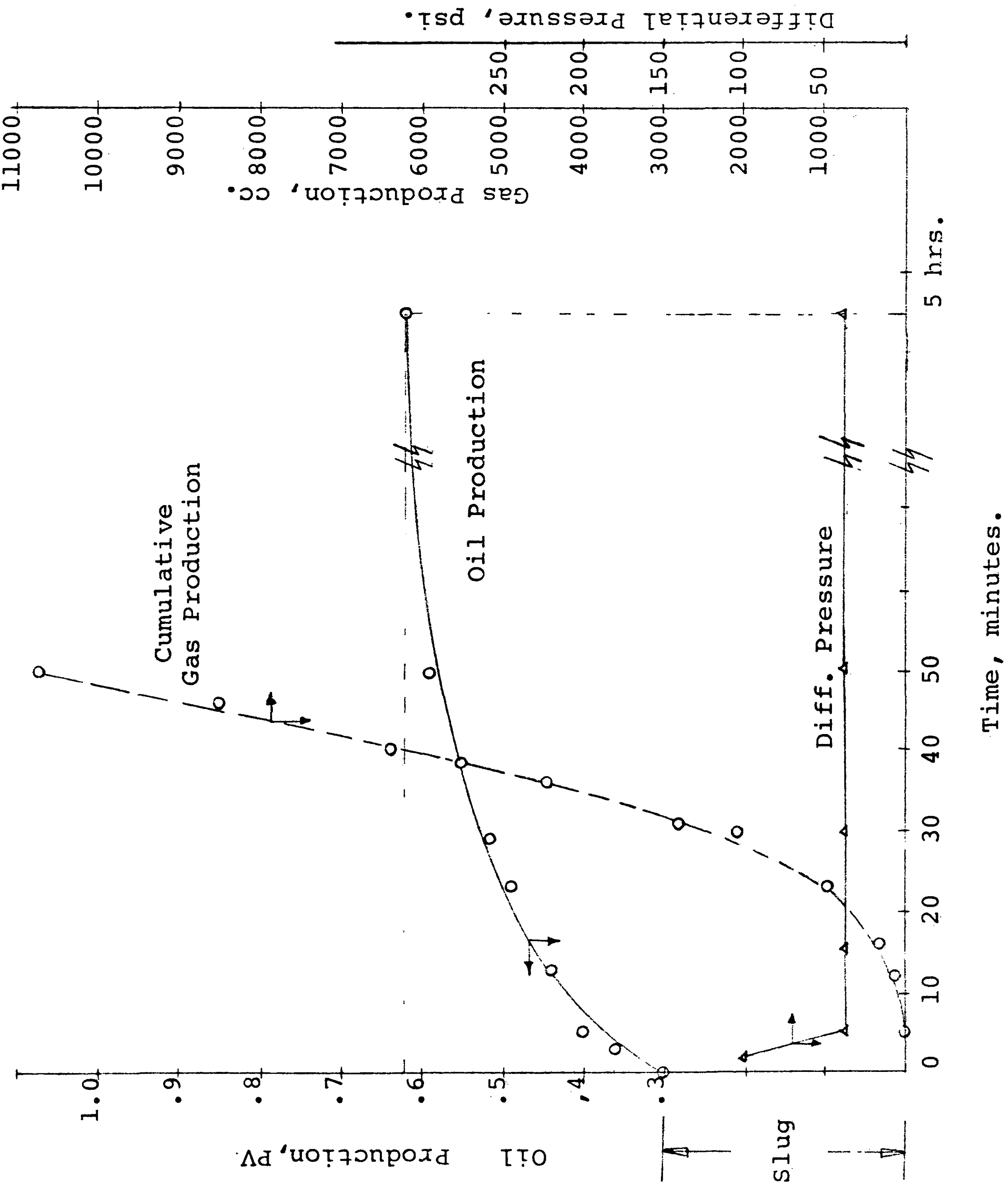


Figure 12

Displacement Performance with Internally Generated Oil-Foam

(30% PV Slug Size -Core 2)



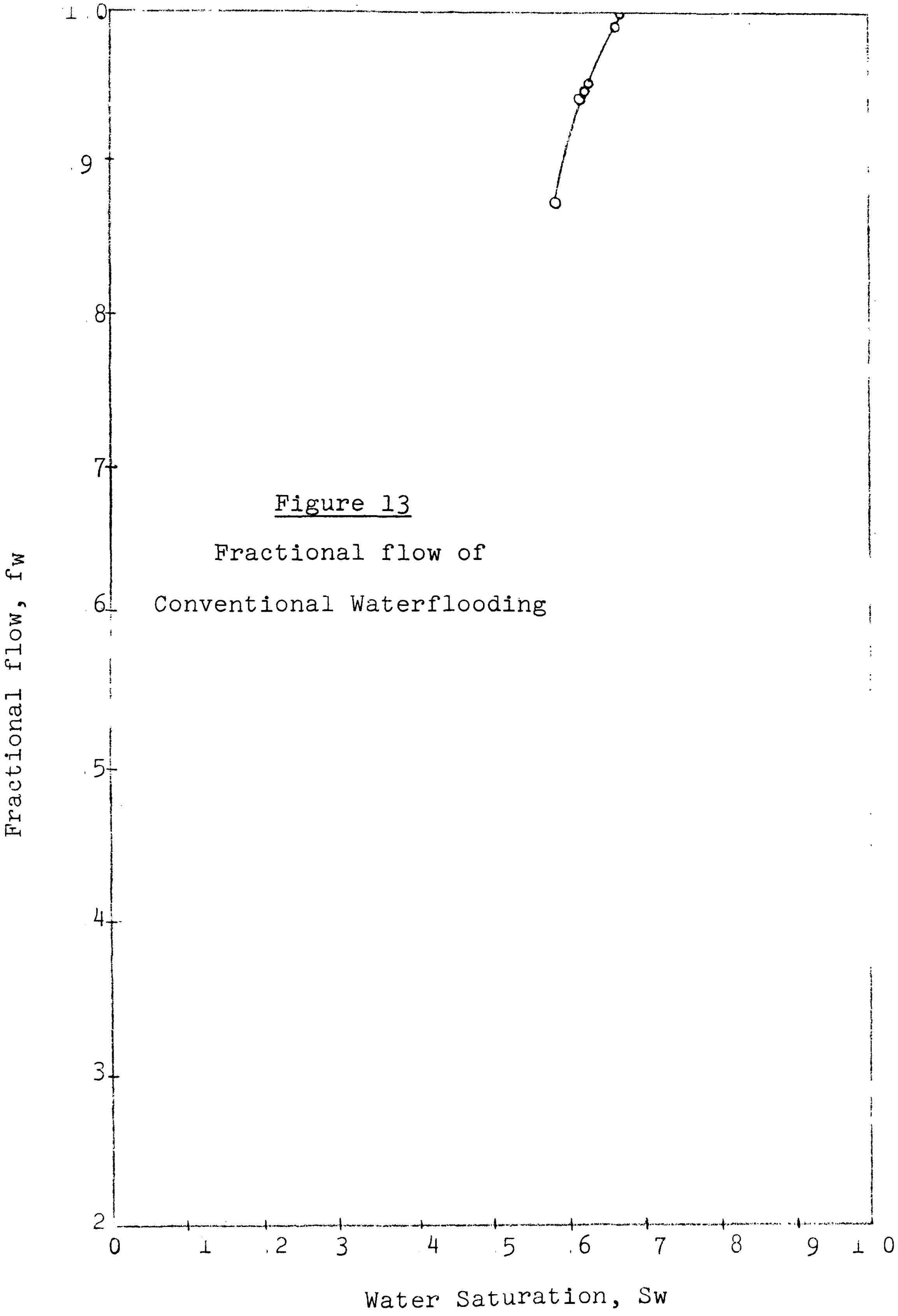


Figure 13

Fractional flow of Conventional Waterflooding

Figure 14

Surfactant Concentration of Produced Oil

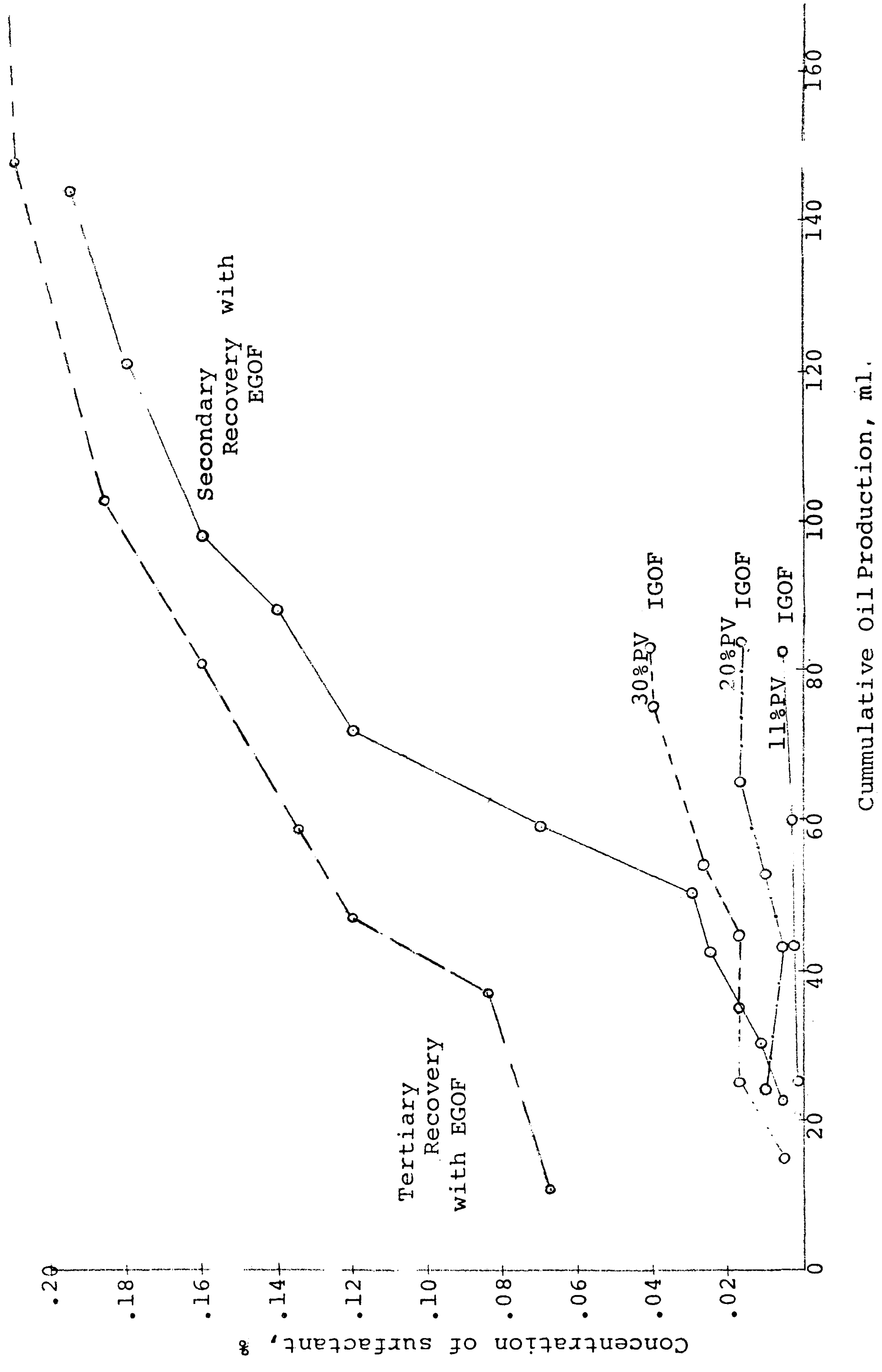
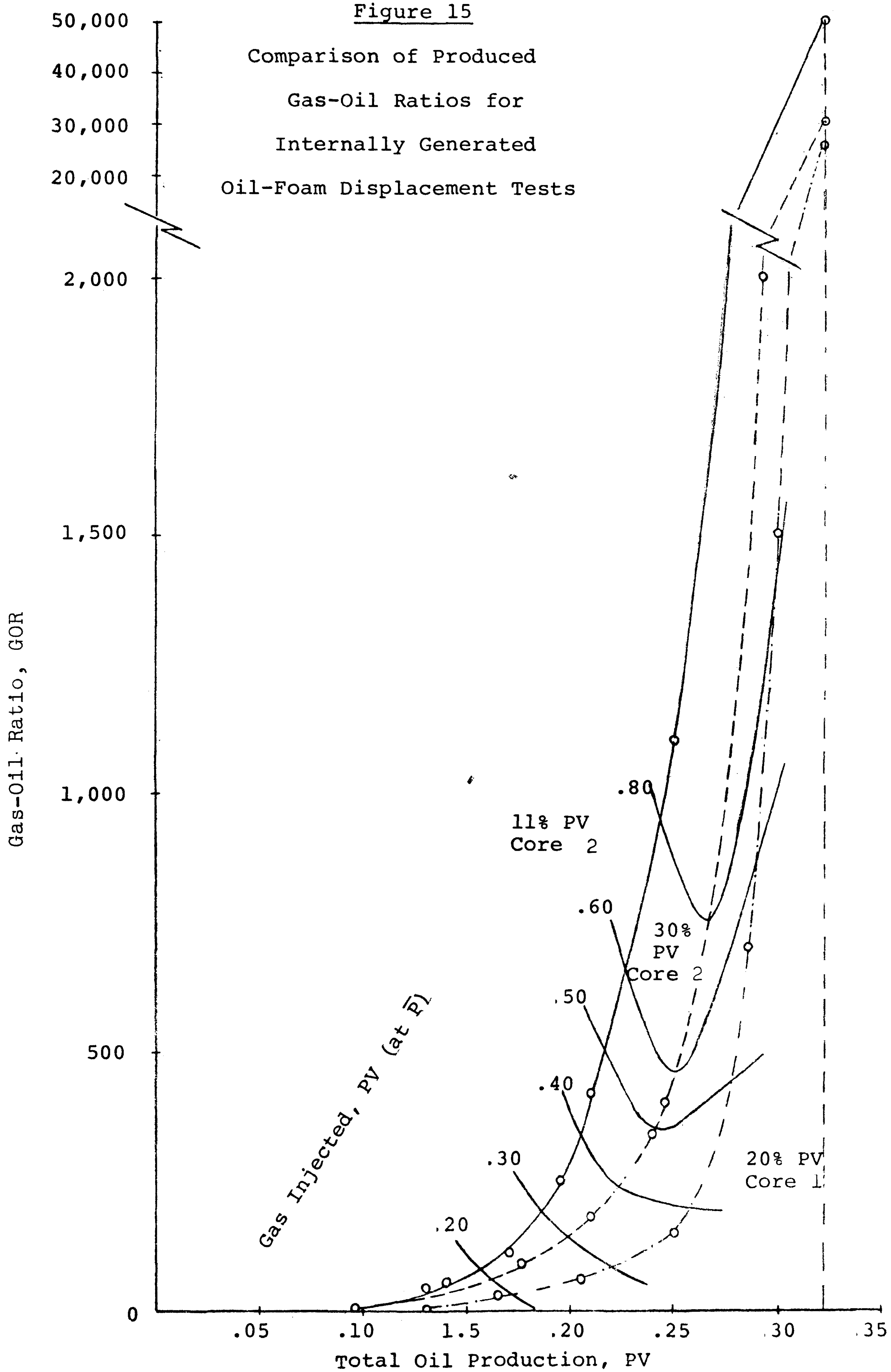


Figure 15

Comparison of Produced Gas-Oil Ratios for Internally Generated Oil-Foam Displacement Tests



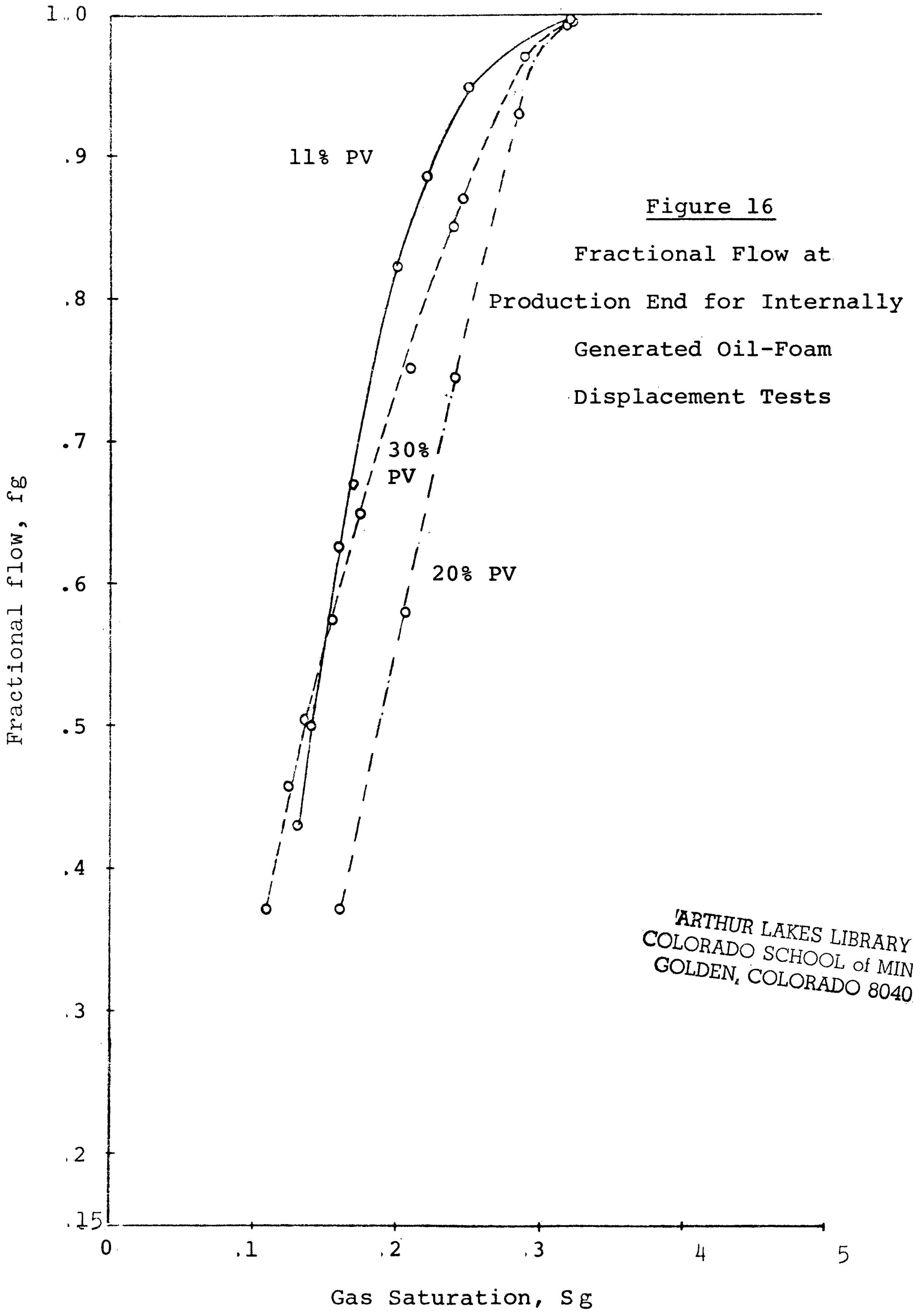


Figure 16

Fractional Flow at Production End for Internally Generated Oil-Foam Displacement Tests

Figure 17

Pressure Behavior for Oil-Foam Displacement Tests

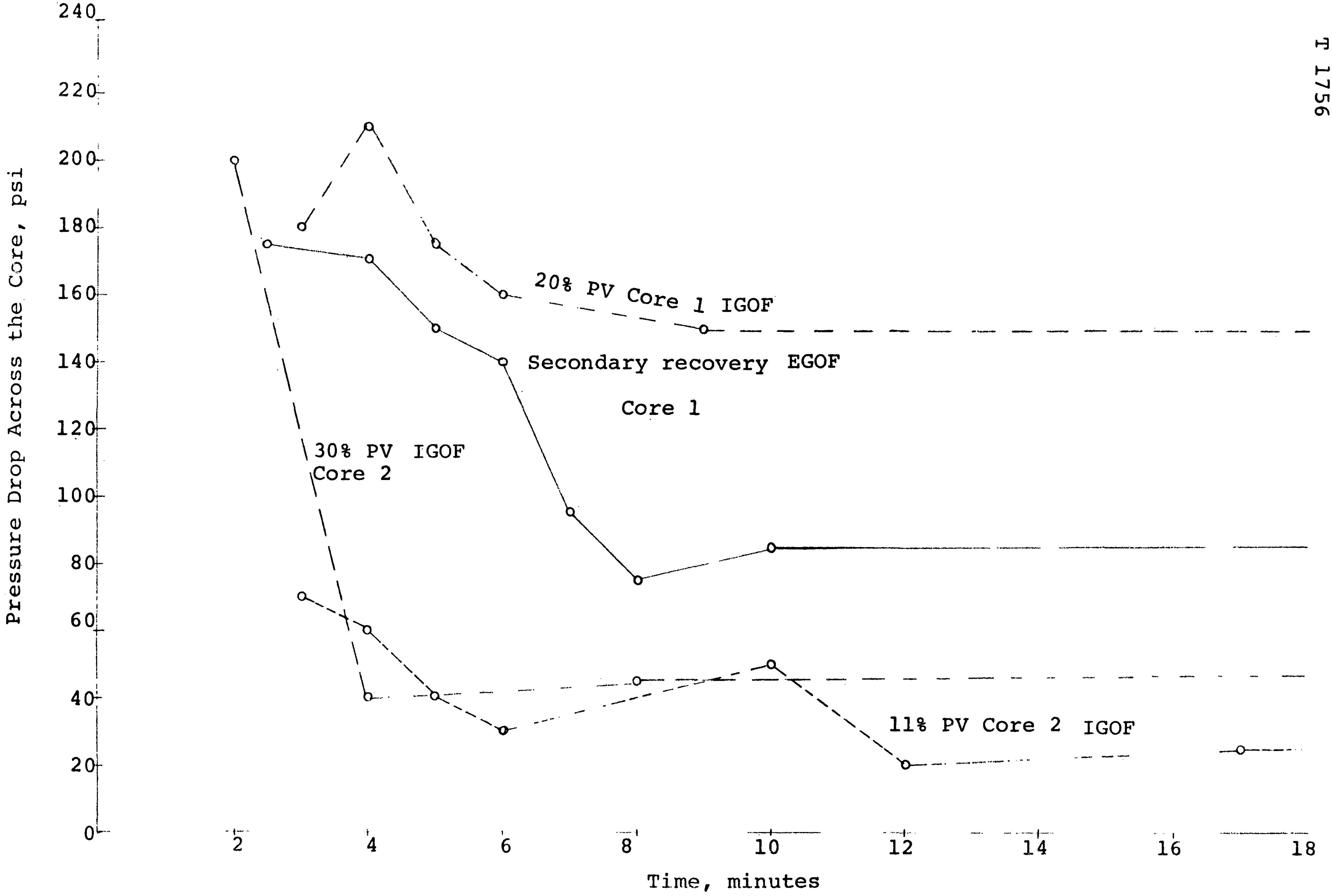
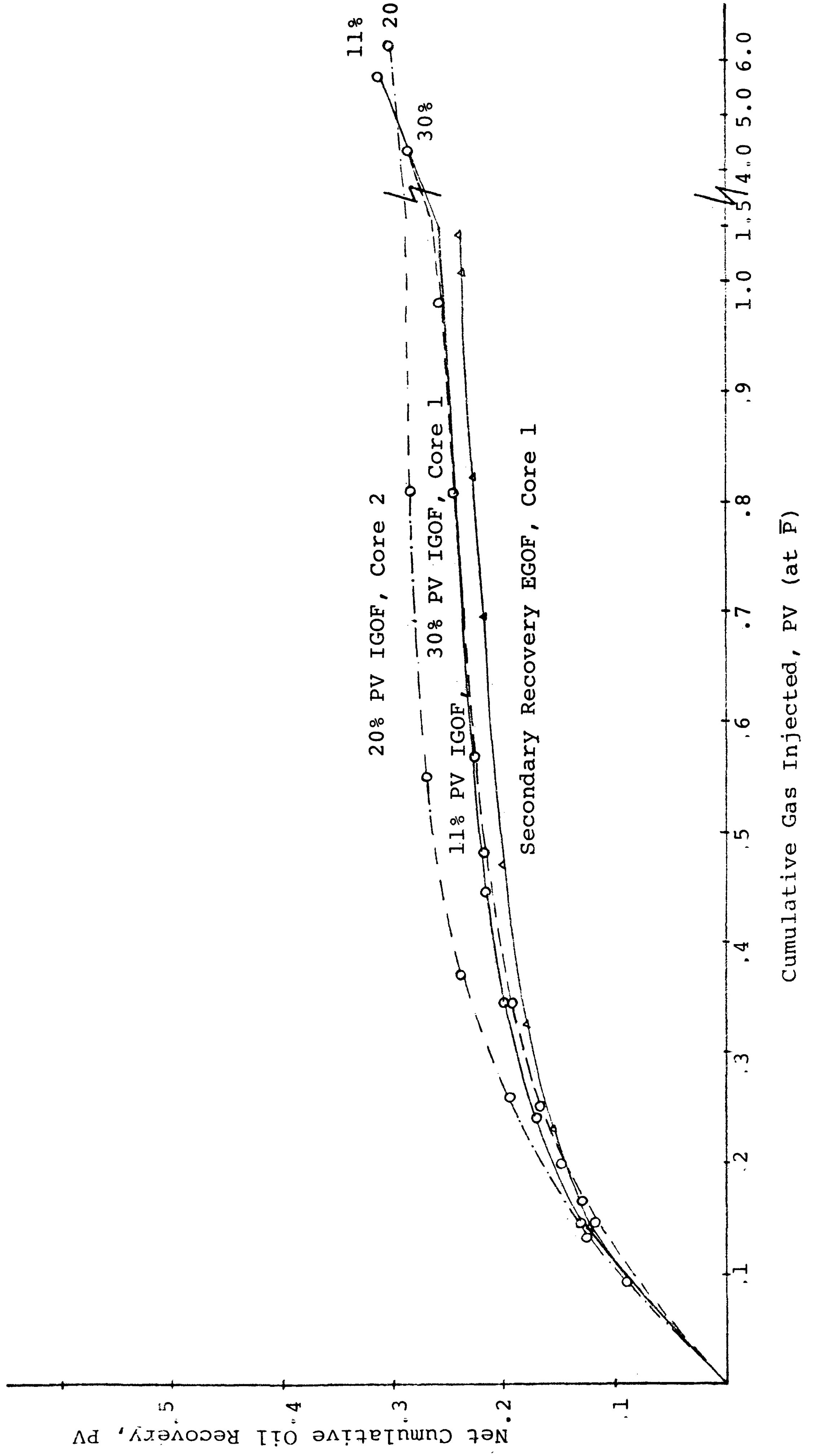


Figure 18

Comparison of Net Oil Recoveries for

Externally and Internally Generated Oil-Foam



5. DISCUSSION AND CONCLUSIONS

5.1 Oil Recovery

The conventional waterflooding carried out in Core 2, See Table 5 and Figure 7, showed an oil recovery of 101 ml., which represents 54% of the oil in place at the beginning of the water injection, or 39.4% of the pore volume. Figure 15 shows the fractional flow in which the final saturation conditions after the test were 66 and 34% for water and oil, respectively.

Table 6 and Figure 8 summarize the results and performance for the tertiary oil recovery test using externally generated oil-foam. It was found that the total net oil recovered amounted to 15.7% of the pore volume. Table 7 and Figure 9 represent the data and recovery performance for the secondary oil recovery with externally generated oil-foam. Total net oil recovery was 23.8% PV.

According to these data, it appears that under those conditions, oil-foam generated outside the porous rock is less effective for recovering oil than by conventional waterflooding. The difference was 23.7% and 15.6% PV for tertiary and secondary recovery, respectively.

Tables 8, 9 and 10, and Figures 10, 11, 12 and 18, show the recovery data and displacement performances of all tests using internally generated oil-foam. It was found that total oil production reached values of 32.03, 32.56 and 32.42% of the pore volume for slug sizes of 11, 20 and 30% PV, respectively. Net oil recovery was 31.5, 30.5 and 28.30% PV, respectively. According to these results, the slug size does not appear to affect ultimate oil recovery. It is shown in Figure 13 that regardless of slug size, and for the same core, equal volumes of oil were recovered at gas breakthrough. Oil recovery with oil-foam generated inside the porous rock was about 9.3% PV less efficient than conventional waterflooding.

In the above experiments, net oil recovery was computed from the effluent surfactant concentrations and the amount of oil recovered. By neglecting the small volume of pure surfactant contained in the oil solution, net oil recovery is calculated with the following equation:

$$\text{Net Oil Recovery (PV)} = \left[1 - \frac{C}{.2\%}\right] \frac{Vop}{PV}$$

Where, PV = Pore volume of the core

C = Surfactant concentration in effluent

.2% = Surfactant concentration of original solution

Vop = Volume of oil produced

5.2 Pressure Behavior

Figure 17 shows the pressure behavior during the displacement tests using both externally and internally generated oil-foam. Up to gas breakthrough, the pressure drop distribution followed an irregular but decreasing trend. The inability to maintain a constant pressure drop in the core indicated that oil and gas were present as foams in the core, and that either the increased viscosity of the foam or a pore-jamming of the foam caused the pressure drop. Once gas broke through, gas had a continuous flow path available and could flow as a separate phase.

5.3 Oil and Gas Flow

Table 7 presents the gas-cut (fg) calculations at outlet pressure for the secondary recovery with externally generated oil-foam. The oil and gas rates were determined at atmospheric pressure, then, fg was calculated using the following equation:

$$f_{gd} = \frac{1}{1 + \frac{Qo}{Qg} \frac{P_o}{P_a}}$$

Where, f_{gd} = Gas-cut at outlet pressure

Qo = Oil production rate

Qg = Gas production rate

Po = Outlet pressure

Pa = Atmospheric pressure

When the fg approached a constant value (and also the GOR's) and was equal to the injection gas-cut, then a steady-state flow condition was obtained and the relative permeability could be calculated. At this steady-state no change in saturation takes place inside the core. With this in mind, it appears that externally generated oil-foam remains as foam inside the core, probably destroying and rebuilding themselves until a continuous gas phase developed, then they entered the core as two distinct phases instead of as foams.

Figure 16 shows the plot of gas-cut vs. average gas saturation for tests using internally generated foam. The gas and oil flow behavior was quite different for the different slug sizes, but fg approaches the same gas saturation as oil recovery decreases. Gas-cut (fg) was calculated at a given gas saturation from the smoothed plot of gas-oil ratios. According to this plot, 20% PV slug size had a better displacement performance than the other two slug sizes. From the smooth plots, gas-cut at mean pressure was calculated from the equation:

$$f_{gm} = \frac{1}{1 + \frac{1}{GOR} \cdot \frac{Bg}{Bo}}$$

Where, f_{gm} = Gas-cut at mean pressure

GOR = Gas-oil ratio

Bg = Gas volumetric factor

Bo = Oil volumetric factor

Figure 15 shows the relationship between gas-oil ratios and gas injection as a function of oil recovery. Although the same oil recovery was obtained at high GOR for all slug sizes, better performance was observed for 20% PV slug size. These results demonstrated that core characteristics have some definite influences on the oil-foam flow in porous media.

5.4 Conclusions

1. Oil-foams generated outside the porous medium could be injected into the core. They remained as foams probably by destroying and rebuilding themselves until a continuous gas phase exists; then they entered the core as two distinct phases.

2. Oil-foams could be generated inside the porous medium and remained as foams until a continuous path is generated by the gas; then it was a straight gas-drive.
3. Conventional waterflooding showed 15.4% PV and 11.9% PV more oil recovery than externally and internally generated oil-foam (at 1.0 PV gas injection), respectively.
4. Internally generated oil-foams recovered approximately 3.5% PV more oil than the externally generated (at 1.0 PV gas injection)
5. Using the same core, and slug sizes of surfactant solution between 11% PV and 30% PV, there was no change in ultimate oil recovery and in oil recovery at gas breakthrough.

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