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LABORATORY STUDY OF NITROGEN MISCIBLE DISPLACEMENT OF LIGHT OIL--TOPICAL REPORT

By

Feliciano M. Llave

David Hudgins

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September 1989

Performed Under Cooperative Agreement No. FC22-83FE60149

IIT Research Institute

National Institute for Petroleum and Energy Research

Bartlesville, Oklahoma

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TABLE OF CONTENTS

ILLUSTRATIONS

TABLES

LABORATORY STUDY OF NITROGEN MISCIBLE DISPLACEMENT OF LIGHT OIL

By Feliciano M. Llave, David A. Hudgins, and Frank T.H. Chung

ABSTRACT

Systematic slim-tube displacement tests and coreflooding tests were performed to determine displacement mechanisms and the minimum miscibility pressure (MMP) for nitrogen with light oils. Emphasis of the study was on the injection of a slug of solution gas before nitrogen gas injection. Experimental results indicated a significant reduction in MMP when the slug injection technique was used. The effect of slug size and composition on the MMP was also studied. Candidate oils from Alaskan reservoirs (26° and 48° API) were also tested for the applicability of nitrogen miscible displacement and the slug injection technique. Straight nitrogen displacement of these oils yield MMP values greater than 8,000 psia. By using the slug injection technique, the MMP for these oils were reduced to about 5,000 psia. A series of nitrogen displacement experiments was performed on one of the Alaskan oils at varying gas-oil-ratios (GOR) to determine the effect of the intermediate components (C_2-C_5) of the oil on the MMP.

A correlation for the MMP has also been developed from literature data on pure nitrogen displacement and data obtained from this work. The proposed correlation shows good agreement with the prediction of the MMP of 14 oils tested. More realistic tests for the nitrogen miscible displacement method were performed in a 2-in. diameter, 2-ft long Berea sandstone core to investigate the effects of gravity segregation and mobility ratio on the recovery efficiency. Secondary and tertiary nitrogen injection tests as well as an initial evaluation of foam flooding as an improvement to nitrogen displacement were also performed.

INTRODUCTION

Nitrogen has been successfully used as the injection fluid for enhanced oil recovery (EOR).[1] It has also been widely used in oilfield operations for gas cycling, reservoir pressure maintenance, and gas lift.[2-6] Limitations on availability and cost of using natural gas and carbon dioxide have made nitrogen an economical alternative for gas miscible displacement.

Nitrogen is usually cheaper than carbon dioxide or hydrocarbon gas displacement and has no corrosive effects like carbon dioxide. Current reservoirs[6] in which miscible nitrogen injection are used include Jay field in Florida (EXXON) and Painter field in Wyoming (Chevron). Successful miscible nitrogen injection was also done for East Binger field in Oklahoma (Phillips) and Lake Barre field in Louisiana (Texaco). The conditions that favor miscibility of crude oils with nitrogen include relatively high reservoir pressures and light or volatile oils rich in light and intermediate hydrocarbon (C_2-C_5) components.[6] Reservoirs that fit these conditions must be deep enough for the reservoir formation to withstand the high pressures that are required to achieve miscibility.

An important screening factor for the use of nitrogen in enhanced oil recovery is the minimum pressure necessary for nitrogen to achieve miscibility with the crude oil through a multiple contact process in porous media. The determination of the minimum miscibility pressure (MMP) of nitrogen with the oil is helpful in ensuring miscibility at an operating pressure greater than the MMP, at a specified reservoir temperature. The available literature data on the MMP of nitrogen with crude oils and synthetic oils are very scarce; therefore, systematic slim tube tests were conducted to determine the MMP for nitrogen miscible displacement of candidate oils.[7-8]

The high pressure requirement for the use of nitrogen in miscible flooding restricts the application of the process; therefore, methods of reducing the MMP have been investigated. A preliminary study[7-8] on the use of the slug-injection technique showed considerable potential in reducing the pressure needed when using nitrogen. The results indicated that the nitrogen MMP was drastically reduced when a slug of hydrocarbon gas followed by pure nitrogen was injected. Considerable work was performed to study the effect of the composition and size of the slug on the reduction of the MMP.

This report presents the results of a comprehensive laboratory study of nitrogen miscible flooding for enhanced recovery of light oil. Slim-tube displacement tests using nitrogen and solution gas slug injection as well as coreflooding tests were performed to determine the displacement mechanisms with the oil. The MMP was determined for a series of experiments using 0.10, 0.075 and 0.05 PV of solution gas slug followed by nitrogen to displace a Lake Barre stock-tank oil (61.5° API gravity) at 279° F. These experiments provided an insight into the effects of the slug size on MMP reduction. The effect of the slug composition was also considered, and a slug of methane and a slug of a different gas mixture to displace the same oil were injected. The results indicated the important effect of the methane and intermediate components of the slug on the MMP. Slim tube experiments were also performed on two Alaskan reservoir oils to assess the applicability of nitrogen miscible displacement. The oil samples studied were an onshore Prudhoe Bay reservoir oil (26° API) and an offshore Beaufort Sea reservoir oil (48° API) recombined at different gas-oil-ratios (GOR).

Coreflooding tests of the nitrogen miscible EOR process were conducted at high pressures in a 2-inch-diameter, 24-inch-long Berea sandstone core. This provided a reservoir-like porous media for testing the effect of several variables. Little or no nitrogen miscible coreflooding experiments have been reported by others, so one objective of this work was to "prove" the process in experiments with laboratory cores. Another objective was to test the effects of gravity stability and secondary versus tertiary nitrogen injection. The viability of foam flooding as an improvement to nitrogen flooding was also studied by injecting a slug of surfactant solution ahead of the nitrogen to generate foam for mobility control. Another objective was to improve the laboratory process of flooding short cores by the addition of a long slim tube in front of the core. Nitrogen flowing through an oil-saturated slim tube generated a miscible transition zone before entering the core, ensuring a miscible flood over the entire length of the core; this was not possible with a short core alone. The nitrogen-Lake Barre reservoir oil system previously studied in slim tube MMP determinations, vapor-liquid equilibria tests, and equation-of-state (EOS) phase behavior simulations was chosen for the coreflood experiments. New work described in this report includes a simple pressure-volume-temperature (PVT) study of the Lake Barre reservoir oil itself. The PVT data were needed for calculating coreflood results. All floods were conducted at 6,000 psig backpressure, at 225° F. By using the same fluids, temperature, pressure, and displacement rate for all seven corefloods, we could determine the effects of different variables.

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NITROGEN MINIMUM MISCIBILITY PRESSURE DETERMINATION

Nitrogen MMP Measurements

Experimental Equipment and Procedure

The experimental apparatus used for the slim tube displacement tests is shown in figure 1. The 120-ft slim tube was constructed from stainless steel tubes of 3/8-inch O.D. and 0.203-inch I.D. The slim tube was packed with silica sand, yielding a porosity of 39 percent and nitrogen permeability of 7 darcies, with a pore volume of 290 cm^3. This unit was designed for a pressure range of up to 10,000 psig. The fluid was injected by means of a calibrated Temco positive-displacement pump, and the effluents were collected for determining the displacement efficiency and mass-balance. Details of the apparatus and the experimental procedure were previously described.[7]

Experimental Results and Discussion

The slim tube studies involved the comparison of the displacement efficiency of injecting pure nitrogen with that obtained by injecting a small slug of hydrocarbon gas followed by nitrogen. The injection of the slug was expected to yield a lower MMP than that of injection of pure nitrogen.

These studies were conducted to determine the changes in the MMP of nitrogen by using a small slug of hydrocarbon gas before nitrogen, with specific emphasis on the effect of the composition and size of the slug injected. A preliminary test was performed last fiscal year on the Lake Barre stock-tank oil (61.5° API gravity).[7-8] The results showed that the injection of a 0.1-PV slug of solution gas before nitrogen injection lowered the MMP drastically, from about 9,400 to 4,170 psia at 279° F.

Systematic tests of injecting 0.05, 0.075 and 0.10 PV solution gas (86.03 mol% C_1, 7.22 mol% C_2, 4.77 mol% C_3, 1.48 mol% C_4, and 0.50 mol% C_5) slugs driven by pure nitrogen to displace Lake Barre oil (STO) at 279° F were made. The results of the experiments using 0.05, 0.075 and 0.10 PV gas slugs showed that the MMP was reduced to 7,500, 5,800 and 4,170 psia, respectively. This showed a drastic reduction compared to the MMP of 9,600 psia required when pure nitrogen was the displacing fluid. Experiments using pure methane slugs of 0.10 PV followed by nitrogen to displace the same oil at 279° F were also performed. The results for the methane study showed that the MMP was about 5,900 psia, which was higher than the MMP when the solution gas slugs were used.

To determine the effect of miscible gas slug composition on the MMP, a second solution gas mixture was used. Experiments using a 0.10-PV slug of this solution gas (75.83 mol% C_1, 10.97 mol% CO_2, 8.25 mol% C_2, 4.95 mol% C_3) driven by pure nitrogen to displace the Lake Barre oil (STO) were performed. The results of the study showed that the MMP was about 4,000 psia at 279° F. Figure 2 shows the plot of the MMP determined versus the slug size for the Lake Barre crude oil at 279° F. The results of the methane slug and the second solution gas slug MMP study are also included.

The slim tube experiments were also focused on Alaska's crude oils to determine the applicability of nitrogen miscible displacement. An onshore reservoir oil sample from Prudhoe Bay, with a crude oil gravity of 26° API, was tested at 200° F with pressures of 4,000, 6,000 and 8,000 psia. The oil recovery by nitrogen displacement was less than 87% at 200° F with pressures below 8,000 psia. The method of injecting a slug (0.10 PV) of produced gas driven by nitrogen was also investigated. The injected solution gas mixture contained 21.60 mol% CO_2, 23.52 mol% C_1, 24.03 mol% C_2 , 28.43 mol% C_3, 1.22 mol% i-C_4 and 1.20 mol% n-C_4. The results indicated that the MMP was reduced to about 4,900 psia. The results of the MMP determination for the pure nitrogen displacement and slug injection techniques for the recovery of this oil are shown in figure 3.

The second oil sample was an offshore Beaufort Sea 48° API crude oil. The stock tank oil was recombined with a solution gas (0.91 mol% N_2, 5.64 mol% CO_2, 77.83 mol% C_1, 7.96 mol% C_2, 4.26 mol% C_3, 2.01 mol% C_4, 0.77 mol% C_5, 0.30 mol% C_6, 0.20 mol% C_7, 0.09 mol% C_8, 0.02 mol% C_9 and 0.01 mol% C_{10}) to a 500 scf/bbl gas-oil ratio (GOR). This recombined oil was then displaced by nitrogen in the slim tube at 250° F. The MMP was determined to be about 6,200 psia. The previous test for the recombined oil of 250 scf/bbl GOR showed that the MMP was greater than 9,000 psia.[7-8] Increasing the GOR from 250 to 500 scf/bbl, reduced the MMP from above 9,000 to 6,200 psia. Another oil batch, using the same stock tank oil, was recombined to yield a GOR of 800 scf/bbl. This oil was also displaced by nitrogen at 250° F. The results of slim tube experiments showed that the MMP is about 5,200 psia. Figure 4 shows the results of the slim tube tests of the Beaufort Sea oil.

MMP Correlation

The literature data for nitrogen miscibility pressures are very limited. Experimental data cited by Firoozabadi and Aziz[9] included only four reservoir oils with known compositions. Their study combined the MMP data of nitrogen with the MMP of lean gas and developed a correlation which is shown in figure 5. The figure also includes the results of the experiments completed in this work. The plot shows that the data from this work do not fall on the correlation they proposed. The concentrations of the intermediate components (C_2-C_5) in the recombined Lake Barre oils were less than those of the reported reservoir oils. Their work was developed primarily from the results of lean gas miscible displacement such that the concentration of methane in the system was not considered in their correlation. When nitrogen gas is used as the displacing fluid, the concentration of methane and the C_2-C_5 components in the reservoir fluid become very important factors in determining the miscibility pressure.

In this work, we developed the following correlation[8] based on the literature data reported for pure nitrogen displacement and the data obtained from this work,

$$MMP = A_1 e^{-R_1} + A_2 e^{-R_2}$$

$$R_1 = [A_3(C_2\text{-}C_5)]/[(C_{7+}M.W.)(T^{0.25})],\ R_2 = [A_4(C_1)^{A5}]/[(C_{7+}M.W.)(T^{0.25})]$$

where A_1 = 5568.3, A_2 = 3641.0, A_3 = 792.06, A_4 = 2.158 x 106 and A_5 = 5.632; MMP is in psia, T is in °F and (C_1) and (C_2-C_5) are mole fractions of methane and intermediate components of the oil, respectively. Table 1 shows a comparison of the calculated MMP versus the experimental MMP for the

TABLE 1. - Comparison between calculated and reported MMP

CO_2,H_2S (C_2-C_5) mol frac	C_{7+} MW	T, °F	C_1, mol frac	MMP, observed	MMP, calculated	Dev %	Oil
0.02470	140.00	279.00	0.0000	9400.0	9022.1	4.020	Lake Barre STO
0.03722	140.00	279.00	0.0937	8850.0	8907.5	-0.650	Lake Barre oil
0.03722	140.00	225.00	0.0937	8500.0	8891.3	-4.603	(recombined)
0.03722	140.00	300.00	0.0937	9000.0	8912.8	0.969	"
0.05503	140.00	279.00	0.2269	6700.0	6657.0	0.642	"
0.05503	140.00	225.00	0.2269	6400.0	6563.6	-2.556	"
0.05503	140.00	300.00	0.2269	6850.0	6688.2	2.362	"
0.07632	140.00	279.00	0.3862	4980.0	5010.0	-0.603	"
0.07632	140.00	225.00	0.3862	4850.0	4980.9	-2.698	"
0.07632	140.00	300.00	0.3862	5100.0	5019.5	1.578	"
0.23090	179.00	279.00	0.4523	4380.0	4336.6	0.990	Lake Como field
0.25170	193.30	164.00	0.5462	4280.0	4174.0	2.476	Painter field
0.32700	191.00	140.00	0.4270	3870.0	3754.2	2.993	Arco A
0.36900	195.00	250.00	0.3273	3660.0	3840.5	-4.932	Hassi-Messoud
					Avg.	±2.29	

recombined Lake Barre oils studied. The calculated MMP for Lake Como oil, Painter oil, ARCO-A oil, and Hassi-Messoud oil also agreed very well with the reported experimental data. The average of absolute deviation for the MMP prediction was less than 2% for the 14 oils tested. This correlation showed that the data obtained from this work were consistent with other reported data when the effect of the presence of methane was considered.

NITROGEN MISCIBLE COREFLOODING STUDIES

Using a core to conduct flow studies offered the opportunity to perform the laboratory tests under conditions as close to actual reservoir conditions as possible. Essentially no work had been published describing nitrogen miscible corefloods, and one objective of this study was to "prove" the EOR process of nitrogen miscible flooding in laboratory cores. This work was one small step closer to providing an insight into actual reservoir flow conditions, as opposed to the slim tube MMP determination testing. A linear core and a slim tube both offered only one-dimensional flow. However, the core came closer to representing two-dimensional flow by introducing more mobility, dispersion, and gravity effects, mainly due to its larger size (in this case, a 2-inch-diameter core as opposed to a 0.203-inch-diameter slim tube).

A second objective of the coreflooding study was to investigate the relative recovery efficiency of the different injection schemes for nitrogen miscible flooding, such as tertiary versus secondary recovery. The third objective was to investigate the phenomenon of foam flooding in a laboratory core. This served as an introductory study for future work in this area.

This study also had a fourth objective: improving the nitrogen coreflooding process by adding a slim tube to the inlet of the core. When using nitrogen, many component "contacts" (and thus, longer contact length) were necessary to generate multiple-contact miscibility (MCM) between the oil and nitrogen. We think that some results were being masked by the short (2-ft) core, wherein the flood was not a miscible flood for most of the core's length. This was remedied by passing the flood first through an 89-ft. long slim tube, in which miscibility was achieved, forming a miscible transition zone. This miscible transition zone was injected into the core, providing a miscible flood for the entire length of the core.

An oil system previously studied in the slim tube and in the PVT cell was chosen, so that the coreflood results could be compared and supported. All seven corefloods used this same oil, as well as the same operating conditions of 6,000 psig and 225° F.

Experimental Equipment

Two reasons that no nitrogen miscible corefloods have been reported were the high pressure and temperature required for most oil-nitrogen systems. The combination of high pressure and temperature made it difficult and expensive to design, build, and maintain a reliable experimental apparatus which would not leak and fail. NIPER successfully built and operated its high-pressure coreflooding system at 10,000 psig and 300° F.

A biaxial coreholder, model no. DCH2-10, was purchased from Temco, Inc. In this case, biaxial meant that the core was stressed by the overburden pressure in all three dimensions, but that the axial stress could not be varied independently from the other two dimensions. Its body was made of 316 stainless steel, while the wetted parts were made of Hastelloy C (for corrosion resistance). It was designed for a maximum pressure rating of 10,000 psi at 300° F. The coreholder was designed with five pressure taps, so that in future foam flooding tests, the core pressure can be monitored at different points. For the seven tests described herein, a tapless sleeve of Buna-N rubber was successfully used. To eliminate leaks due to gas diffusion through the rubber, liquid (water) was used in the annulus between the sleeve and the coreholder body. The water was pressurized by a nitrogen gas cap in a small external vessel to provide the compressibility needed. The overburden pressure was varied by plumbing the nitrogen gas cap to a small HIP positive displacement hand pump.

Another special piece of equipment was the low-dead-volume backpressure regulator (BPR) purchased from Temco, Inc. rated up to 10,000 psi at 300° F. It was a dome-loaded type, controlling the backpressure to equal the dome-load pressure. The dome-load pressure was provided by nitrogen and was adjusted with a small HIP hand pump. Proper BPR operation required a multiple-valve assembly and a pressure vessel containing water plus a nitrogen gas cap. A digital thermocouple readout monitored test temperature.

Figure 6 shows a schematic diagram of the nitrogen coreflooding system. It was successfully designed and tested for a maximum pressure of 10,000 psi at 300° F. The coreholder and the 89-ft slim tube were housed in a large forced-air oven. Experience with early valve failures at high temperature required placing all valves outside the oven. The BPR was also placed outside the oven for convenience. Its small flow volume being at room temperature was insignificant. All flow tubing used for the system was 1/8-in. O.D., 0.065-in. I.D. tubing rated at 12,000 psi. Monel tubing material was used inside the oven because of its superior corrosion resistance. Tubing made of 316 stainless steel was used for lines outside the oven. The system was plumbed with appropriate valves so that the core and the slim tube could be tested independently, or in combination. The coreholder was mounted on a rotating stand, so that its angle could be varied from horizontal to vertical. Also it was easily rotated by 180° so that it was possible to inject water into the bottom of the vertical core, in a gravity-stable manner, and then flipped over to inject nitrogen into the top of the core, under gravity-stable conditions. The slim tube and Berea sandstone core properties are presented in table 2.

A variable-speed, Ruska positive-displacement pump was filled with a displacement fluid (automotive transmission fluid). This fluid was injected at a constant rate into the bottom of floating piston pressure vessels containing the various test fluids. The produced fluids were monitored by means of a test separator, similar to the unit used for the slim tube MMP tests. It measured cumulative oil and water in a long, thin calibrated test tube, ±0.1 cm^3 accuracy. The produced gas was monitored using a gas buret system by measuring the water displaced by the gas, with ±2cm^3 resolution. The effluents were measured at atmospheric conditions, after being flashed through the BPR. Eight Sensotec 0 to 7,500 psig pressure transducers measured test pressure at different locations. They were high-temperature-compensated, high-accuracy transducers (±0.1%, ±7.5 psi) connected to a common eight channel digital readout.

Experimental Procedure

Each coreflood was conducted according to the procedure listed below:

1. Inject several pore volumes of Stoddard solvent into the core to remove remaining oil.

2. Inject several pore volumes of isopropyl alcohol to miscibly displace the Stoddard solvent and water.

3. Inject several pore volumes of methanol to miscibly displace the IPA and water.

TABLE 2. - Core, slim tube, and fluid properties at test conditions of 6,000 psig, 225° F

Berea sandstone core properties

O.D. = 2 in. (5.08 cm)
Length = 24 in. (60.96 cm)
Pore volume = 245 cm^3
Bulk volume = 1,236 cm^3
Porosity = 19.8%
Permeability = 460 md
Initial oil saturation = 60%

Sand-packed coiled slim tube properties

Material: 316 stainless steel, seamless tubing
O.D. = 0.375 in.
I.D. = 0.203 in. (0.5156 cm)
Length = 89 ft, 1 in. (2715.3 cm)
Cross-sectional flow area = 0.2088 cm^2
Pore volume = 214.8 cm^3
Bulk volume = 567.0 cm^3
Porosity = 37.9%
Permeability = 12.2 darcies
Packed with = 80-100 mesh silica sand

Fluid properties at test conditions (6,000 psig, 225° F)

Reservoir oil

Solution GOR = 564 scf/bbl
Bubble-point pressure = 2,160 psig
Density = 0.6120 g/cm^3
Viscosity = 0.27 cp
Formation volume factor = 1.4404
Thermal expansion factor = 1.1284 (from 80° F to 225° F)
Stock-tank oil gravity = 61° API at 60° F

Brine, 1% NaCl

Density = 0.9742 g/cm^3
Formation volume factor = 1.0316
Thermal expansion factor = 1.0469
Viscosity = 0.266 cp

Nitrogen

Density = 0.2801 g/cm^3
Thermal expansion factor = 1.2569
Viscosity = 0.0297 cp

4. Purge the remaining methanol and blow dry with nitrogen at 225° F.

5. Allow the system to cool down to room temperature and measure the nitrogen permeability with a soap-film flowmeter and a stopwatch.

6. Evacuate the core at 225° F.

7. Calibrate the pressure transducers at 225° F, using the built-in shunt calibration.

8. Adjust the BPR dome load to 6,000 psig by means of the HIP hand pump.

9. Saturate the core with brine and determine the pore volume at test conditions (as measured by the volume-calibrated Ruska pump). Keep the overburden pressure at least 1,000 psi above the core internal pressure.

10. Allow some brine to flow through the BPR to check for proper regulator operation.

11. Inject oil into the top of the core at a gravity-stable rate of 56 cc/hr to displace brine at 6,000 psig, 225° F.

12. Continue the oil injection to residual (connate) water saturation. This is the point where essentially no more brine is produced.

13. Determine the initial oil-in-place (initial oil saturation), which is equal to water produced during the oil injection.

14. Compress the nitrogen gas to 6,000 psig and inject into the core at approximately 8 cm^3/hr rate, which is a gravity-stable rate if injected into the top of a vertical core (we conducted the waterflood in test No. 1 by injecting brine into the bottom of the core at 56 cm^3/hr rate, which was a gravity-stable rate).

15. Periodically record the inlet and outlet pressures, overburden pressure, room temperature, effluent oil, gas and water volumes, and pump displacement volume.

The slim tube was prepared and flooded in the same way, except for steps 1 through 3. It was cleaned with distilled water, toluene, methanol and petroleum ether. Of course, the slim tube could not be flooded in a gravity-stable manner because it was coiled, which provided only a horizontal flow path.

Fluids Used in the Corefloods

An oil-nitrogen system previously studied was chosen for the corefloods. All seven tests used the same recombined Lake Barre reservoir oil with a solution gas-oil ratio (GOR) of 564 scf/bbl.[7-8] The phase behavior of this oil with nitrogen was previously studied, and a pseudo-ternary phase diagram had been generated and matched closely by an equation-of-state (EOS) simulator. Previously reported slim tube tests performed on this oil determined the nitrogen MMP of 4,850 psi at 225° F.[7] All coreflooding tests reported herein were conducted at a backpressure of 6,000 psig at 225° F to ensure multicontact miscibility between the oil and the injected nitrogen.

A simplified PVT study of the Lake Barre reservoir oil was conducted for this new work. The bubble-point pressure was determined to be 2,160 psig at 225° F. At 6,000 psig, the thermal expansion factor (TEF) of the oil was measured to be 1.1284 cm^3/cm^3, from 80° to 225° F. A flash liberation experiment measured the oil's formation volume factor (FVF), which was in good agreement with the value obtained by material balance of the later stage of one of the corefloods' oil-saturation procedures. The properties of the oil tested are presented in table 2.

The same brine was used for all corefloods, including the initial brine saturation and waterflooding stages. The brine consisted of 1% sodium chloride (by weight), in distilled water. Pure nitrogen (99.84%) was used for all nitrogen injections. By using the same fluids, pressure, temperature and displacement rates for all coreflooding tests, other parameters could be varied, and the effects could be compared. The brine and nitrogen gas properties are also presented in table 2.

Coreflood Test Results and Discussion

A description of each of the seven corefloods, as well as the oil recovery results for each test is presented in table 3. The results of the oil recovery versus pore volumes injected for each of the seven corefloods are plotted in figure 7.

The first test consisted of a waterflood of the core to residual oil saturation, followed by a tertiary nitrogen flood to residual brine saturation. The core was in a vertical position for the entire test. During the initial oil saturation procedure, the Lake Barre reservoir oil was injected into the top of the core at 56 cm^3/hr to displace the brine in a gravity-stable manner. The waterflood consisted of injecting the brine into the bottom of the core at 56 cm^3/hr, until it had reduced the initial oil saturation of 61.6% PV to a residual oil saturation of 39.6% PV, for a recovery of 35.7% of the original oil-in-place (OOIP). The following nitrogen flood consisted of injecting the gas into the top of the watered-out core at 8 cm^3/hr. At first, only the brine was produced, until the nitrogen formed a miscible zone and a bank of oil and moved them downdip. Nitrogen breakthrough occurred at 0.41 PV of nitrogen injected. The recovery at this point was 60.7% of OOIP. The displacement mode ultimately raised the overall recovery efficiency to 64.8% of OOIP. The oil saturation was reduced from 39.6% to 21.7% PV.

Test No. 2 was a secondary nitrogen flood. For this test, there was no high water saturation within the core to interfere with the miscible

TABLE 3. - Results of nitrogen miscible corefloods

Test No.	OOIP, cm^3	S_{oi}, %	PV, cm^3	$E_{r\,ultimate}$	$S_{or\,ultimate}$	$E_{R\,gas\ breakthrough}$
1 (core)	152.4	61.58	247.51	64.8	[1]21.70	60.7% @ 0.41 PV injected
2 (core)	147.9	58.98	250.82	75.1	14.7	51.5% @ 0.31 PV injected
3 (core)	149.8	59.45	251.97	81.0	11.3	71.5% @ 0.475 PV injected
4 (slim tube)	167.2	75.82	220.42	97.8	1.6	97.0% @ 0.752 PV injected
5 (slim tube and core)	308.2	65.57	470.04	91.3	5.7	81.2% @ 0.557 PV injected
(-slim tube portion)	158.2	72.10	219.48	97.8 assumed	1.6	
(-core portion)	150.0	59.84	250.67	84.5	9.3	
6 (core)	155.3	61.53	252.32	64.7	21.7	56.0% @ 0.443 PV injected
7 (core)	155.6	60.73	256.16	70.7	17.8	65.9% @ 0.538 PV injected

TABLE 3. - Results of nitrogen miscible corefloods (continued)

Test No.	Description
1	Waterflood + tertiary nitrogen flood of vertical core (gravity stable)
2	Secondary nitrogen flood of horizontal core (gravity unstable)
3	Secondary nitrogen flood of vertical core (gravity stable)
4	Secondary nitrogen flood of slim tube (gravity unstable)
5	Secondary nitrogen flood of slim tube + vertical core (gravity unstable in slim tube)
6	Secondary nitrogen flood following 0.1 PV of 0.1% foaming solution, in horizontal core (gravity unstable)
7	Secondary nitrogen flood following 0.1 PV of 1.0% foaming solution in vertical core (gravity stable)

[1] S_{orw} = 39.6%

displacement. The nitrogen did not have to form a bank of oil from discontinuous droplets, as in test No. 1. The core was in a horizontal position during the nitrogen injection. Despite the gravity-unstable displacement, the ultimate oil recovery was 75.1% of OOIP, higher than in the first test. Breakthrough (BT) occurred at 0.31 PV nitrogen injected, at 51.5% of OOIP oil recovery. Compared to the first test, this was an earlier breakthrough at a lower recovery level. In spite of the low recovery at BT, the nitrogen continued to displace the oil and ultimately achieved a higher recovery because of the low initial brine saturation.

The experimental procedure for the third test was the same for test No. 2, except that No. 3 was gravity-stable during the nitrogen flood. This test showed a delayed nitrogen breakthrough at 0.475 PV injected, with an oil recovery of 71.5% of OOIP. The ultimate oil recovery was also higher than the first two tests at 81.0% of OOIP.

The 11.3% PV residual oil saturation achieved in the third test was not representative of the lower residual oil saturation obtained in most miscible gas floods in "clean" porous media (without any significant amount of dead-end pores). As mentioned earlier, we suspected that the results were being masked by the short length (24 inches) of the Berea sandstone core. It was possible that the flood was not miscible over the entire length of core. Test No. 4 was performed as a preliminary step to the fifth test. This test was a secondary nitrogen flood of the slim tube only. Performing this run determined how much of the oil recovery (when the slim tube and core are connected) was recovery from the slim tube. The slim tube's greater length and more ideal one-dimensional flow gave a higher ultimate oil recovery, 97.8% of OOIP and lower residual oil saturation at 1.6% PV than any of the corefloods. This test also showed a sharper and later nitrogen breakthrough at 0.752 PV injected, 97.0% of OOIP recovery. Because of its horizontal flow path, displacement in the slim tube was not gravity stable. However, Nouar and Flock[10] reported that viscous fingering was suppressed in the miscible flood because of the small cross-sectional width of slim tubes.

The immiscible displacement of brine by oil during the initial oil saturation procedure for test No. 4 gave a much more gradual breakthrough than did the core initial saturation procedures, which were gravity stable. This required more time and more oil to achieve an irreducible water saturation. The final water saturation achieved was not an absolutely irreducible saturation, since small amounts of water were still being produced when the oil flood was stopped.

Test No. 5 was performed using the 89-foot, sand-packed slim tube plumbed in front of the core to generate miscibility before entering the core. The secondary nitrogen flood was gravity unstable in the horizontal slim tube, but gravity stable in the vertical core. Nitrogen broke through at 0.557 PV injected for a breakthrough recovery of 81.2% of OOIP. The ultimate oil recovery from the system for this test was 91.3% of OOIP. To determine the oil recovered from the core portion only, the ultimate oil recovery from the slim tube was assumed to be the same at 97.8% of the OOIP, as determined in test No. 4. This meant that 154.72 cm^3 of reservoir oil was recovered from the slim tube portion. The total oil recovered from the system was 281.50 cm^3. This value less the oil recovery from the slim tube, resulted in an oil recovery of 84.5% of OOIP and 9.3% PV residual oil saturation for the core alone. This residual oil saturation value, being 2 percentage points lower than the recovery determined from the third test, indicated that the use of a short core by itself did mask results somewhat. The slim tube provided a valuable method of generating a miscible zone to inject into the core.

Further tests with the slim-tube-plus-core combination, would be valuable. Such comparisons with the other tests using the core alone might have shown greater improvements, since the other tests had recoveries lower than that determined in test No. 3. In comparison to test No. 1, if an oil bank and miscible transition zone from the slim tube would have entered the watered-out core, oil recovery from the core portion could have been much higher than 64.8%.

The first coreflood to utilize a mobility control agent was test No. 6. It was a secondary flood of the horizontal core, preceded by a 0.1 PV slug of foaming solution. Test No. 2 was identical to this test minus the foamer. The foaming solution consisted of 0.1% active (by weight) surfactant in 1% NaCl brine, with the final solution pH adjusted to 5.5 by the addition of hydrochloric acid. The surfactant was an alpha olefin sulfonate, with 10 to 16 carbon numbers into straight chain part of the molecule. The 0.1% concentration proved to be too low. No increase in differential pressure across the core, indicative of foam generation, was noted. Differential pressure during nitrogen injection remained at 2 to 10 psi, similar to that of the other tests without the foamer injection. No foaming was noticed in the effluent. Since no foam generation occurred to alleviate the gravity override during the gravity unstable nitrogen flood, the ultimate oil recovery was only 64.7%, lower than the 75.1% recovery determined from test No. 2. In fact, the ultimate oil recovery value for test No. 6 was identical to that of the gravity-stable tertiary nitrogen flood in test No. 1, in which the core was completely watered-out before nitrogen injection. The 0.1% concentration should have been high enough to generate foam under ideal conditions, but surfactant losses due to adsorption on the sandstone surfaces probably diluted the concentration below an acceptable level.

A more concentrated 1.0% solution of the same surfactant was used for test No. 7, and the core was vertical; otherwise test No. 7 identical to test No. 6. It was hoped that the surfactant higher concentration would be able to overcome losses and generate foam in the core, but there was no significant rise in differential pressure across the core during nitrogen injection which would have indicated foam generation. Also, no foam was observed in the effluent. Test No. 3 was identical to this test, minus the foamer. The ultimate oil recovery of this test was only 70.7% of OOIP, as opposed to the 81.0% of OOIP for test No. 3. Either the 1.0% solution was also too dilute or the solution simply would not foam with the given oil composition, pressure, temperature, and salinity.

CONCLUSIONS

The following conclusions are drawn from the results of this study of nitrogen miscible displacement of light oil:

Nitrogen MMP Determination

1. The injection of a solution gas slug followed by nitrogen injection can drastically reduce the MMP. Nitrogen alone can achieve miscibility with light oils at pressures higher than 4,000 psia, but in most cases studied,[7-8] the MMP was above 8,000 psia. The MMP reduction in the presence of the slug indicates the strong effect of introducing a miscible zone (volatile hydrocarbons) before nitrogen injection in promoting miscibility between the oil and nitrogen.

2. Increasing the size of the solution gas slug effectively increases the reduction of the MMP. The limit of the MMP reduction is the point when the solution gas becomes the only displacing fluid, without nitrogen.

3. Increasing amounts of methane and intermediate components (C_2-C_5) in the solution gas reduce the MMP.

4. The use of the slug injection technique on the candidate Alaskan oils reduces the MMP to within a reasonable pressure range, less than 5,000 psia. This shows the applicability of using nitrogen as a displacing fluid in Alaskan reservoirs, provided there is an effective method utilized to reduce the high miscibility pressure requirement.

5. The nitrogen MMP decreases with the increase of the solution gas-oil-ratio (GOR). Results of tests of an Alaskan oil indicate the strong effect of the volatile hydrocarbons (C_2-C_5) in the oil on the MMP. The intermediate components are important in allowing the nitrogen to achieve miscibility with the oil.

6. The proposed MMP correlation shows good agreement with the prediction of the MMP of 14 oils tested. This correlation shows the significant contribution of the methane and intermediate components of the oil in effectively predicting miscibility conditions.

Nitrogen Miscible Coreflooding Studies

1. Nitrogen gas miscible flooding can successfully recover a large percentage of the oil in place; that is, far more than would be recovered by either primary production or waterflooding.

2. Injection strategy affects oil recovery considerably. Secondary nitrogen injection in a gravity-stable mode recovered the most oil. Secondary nitrogen injection in a gravity unstable mode resulted in the second highest recovery. Tertiary nitrogen injection in a gravity-stable mode performed worse.

3. A long slim tube is a viable, valuable addition to the coreflooding experiment.

4. In a short core, if the foaming solution does not generate foam, it will hinder the effectiveness of the miscible flood.

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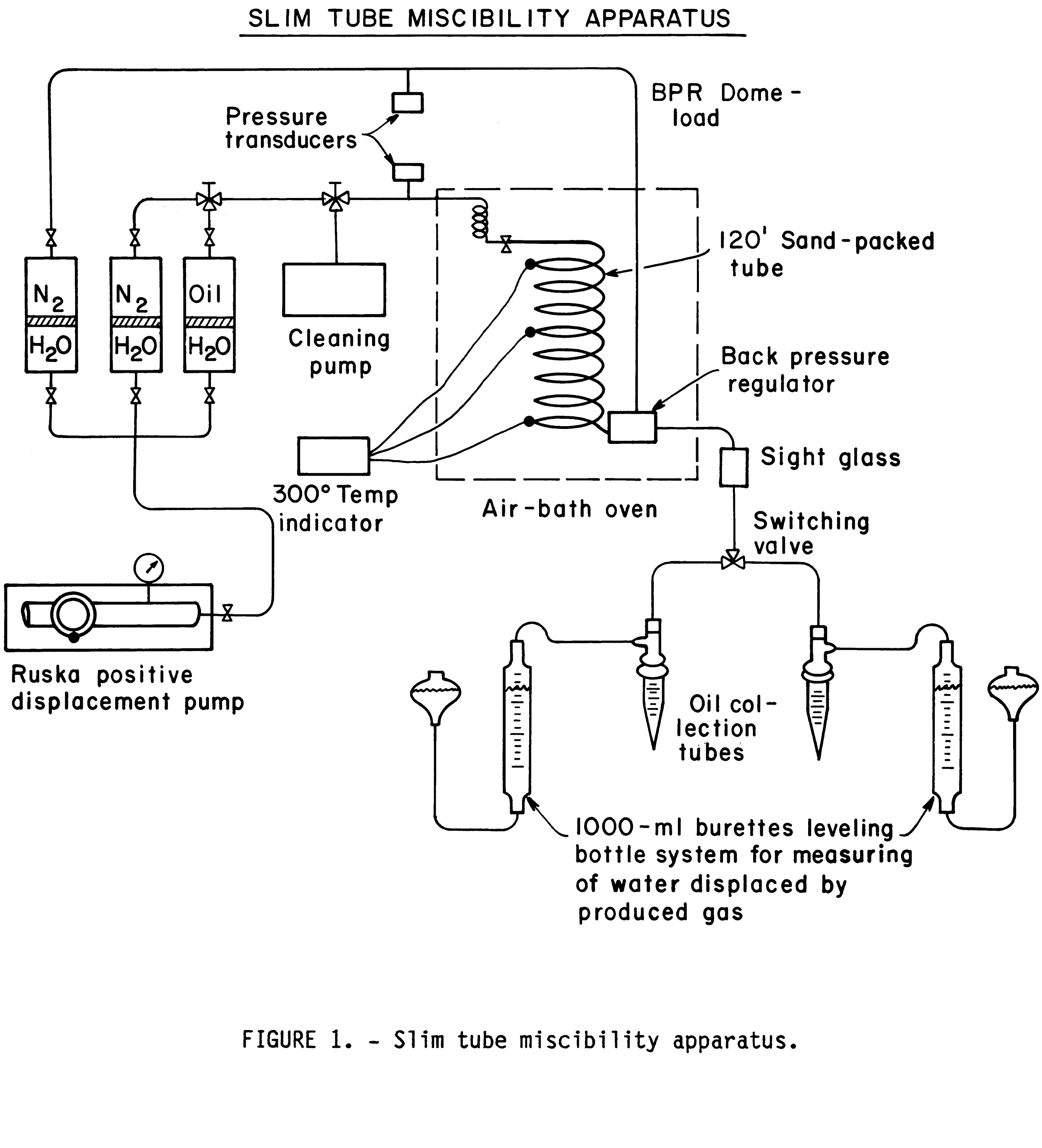

FIGURE 1. - Slim tube miscibility apparatus.

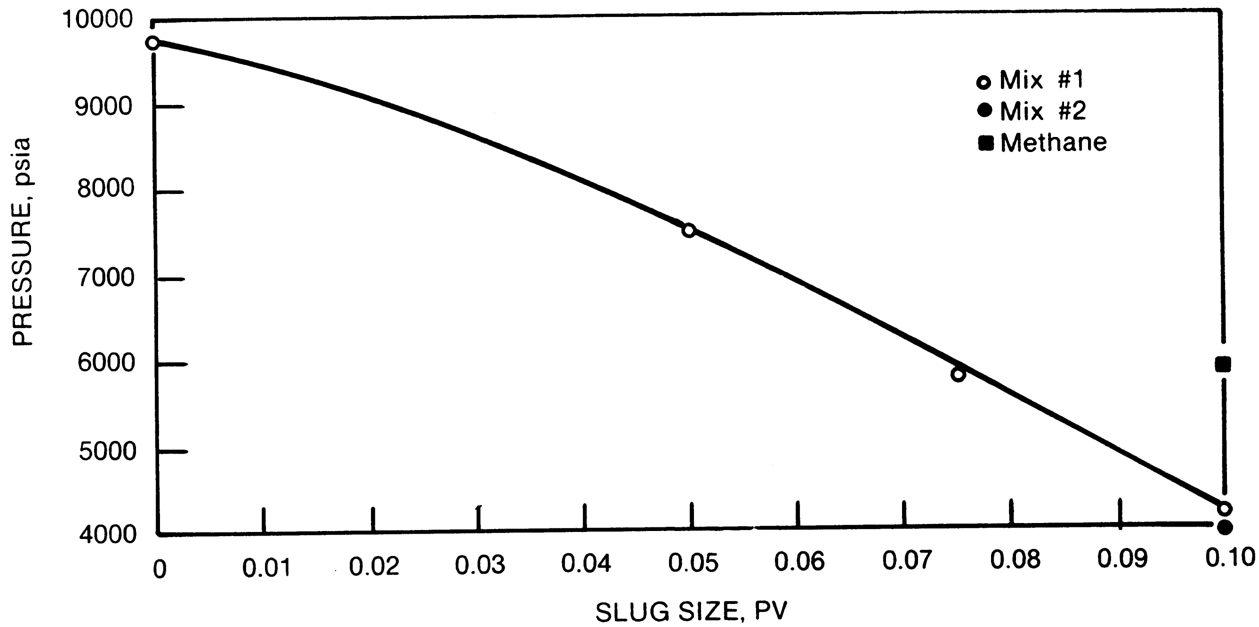

FIGURE 2. - Lake Barre oil MMP versus slug size at 279° F.

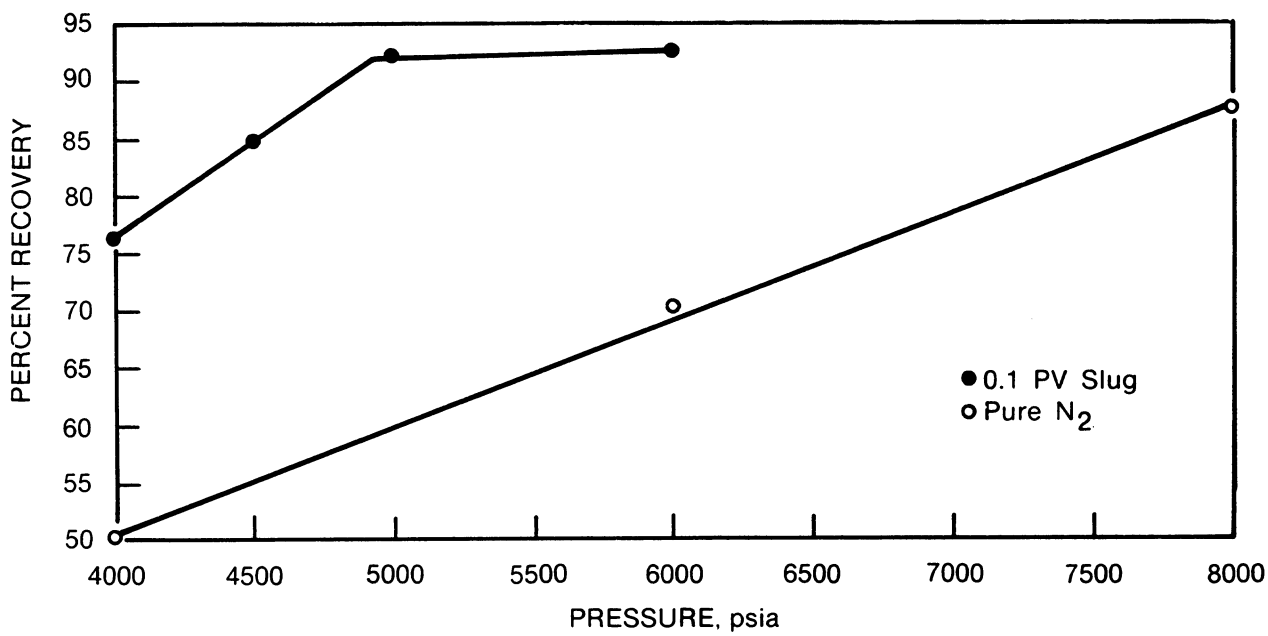

FIGURE 3. - N_2 MMP with Prudhoe Bay crude oil. Percent recovery vs. pressure at 1.2 HCPV, temperature = 200° F.

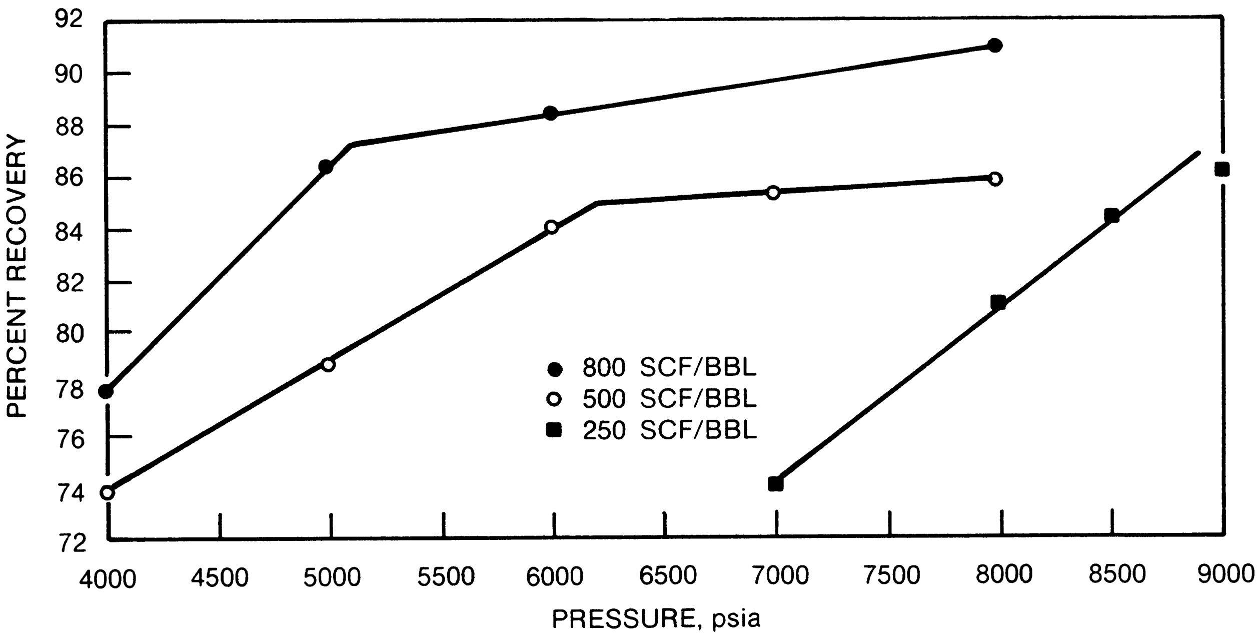

FIGURE 4. - N_2 MMP with recombined Beaufort Sea crude oil. Recovery vs. pressure at 1.2 HCPV, temperature = 250° F.

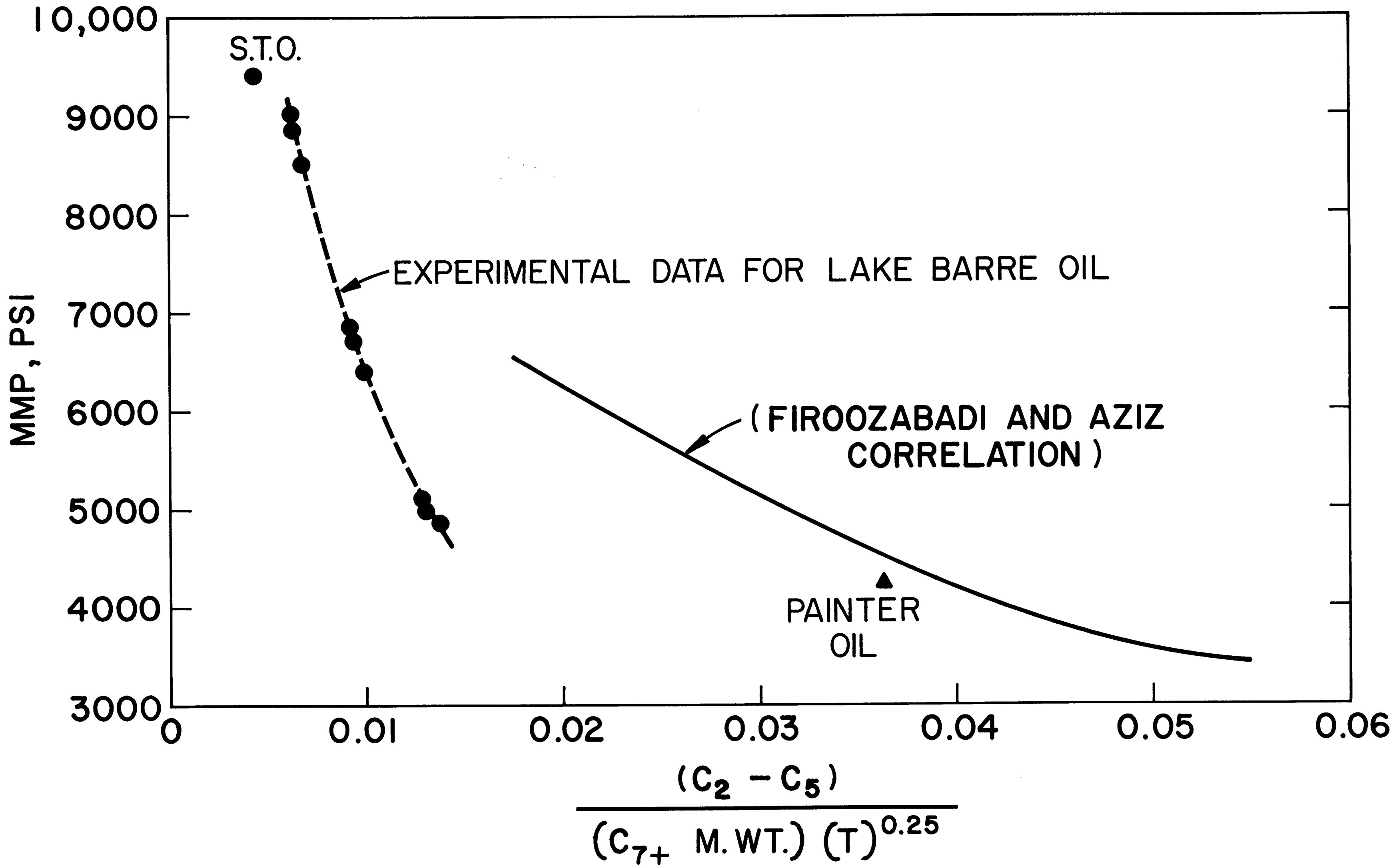

FIGURE 5. - MMP correlations.

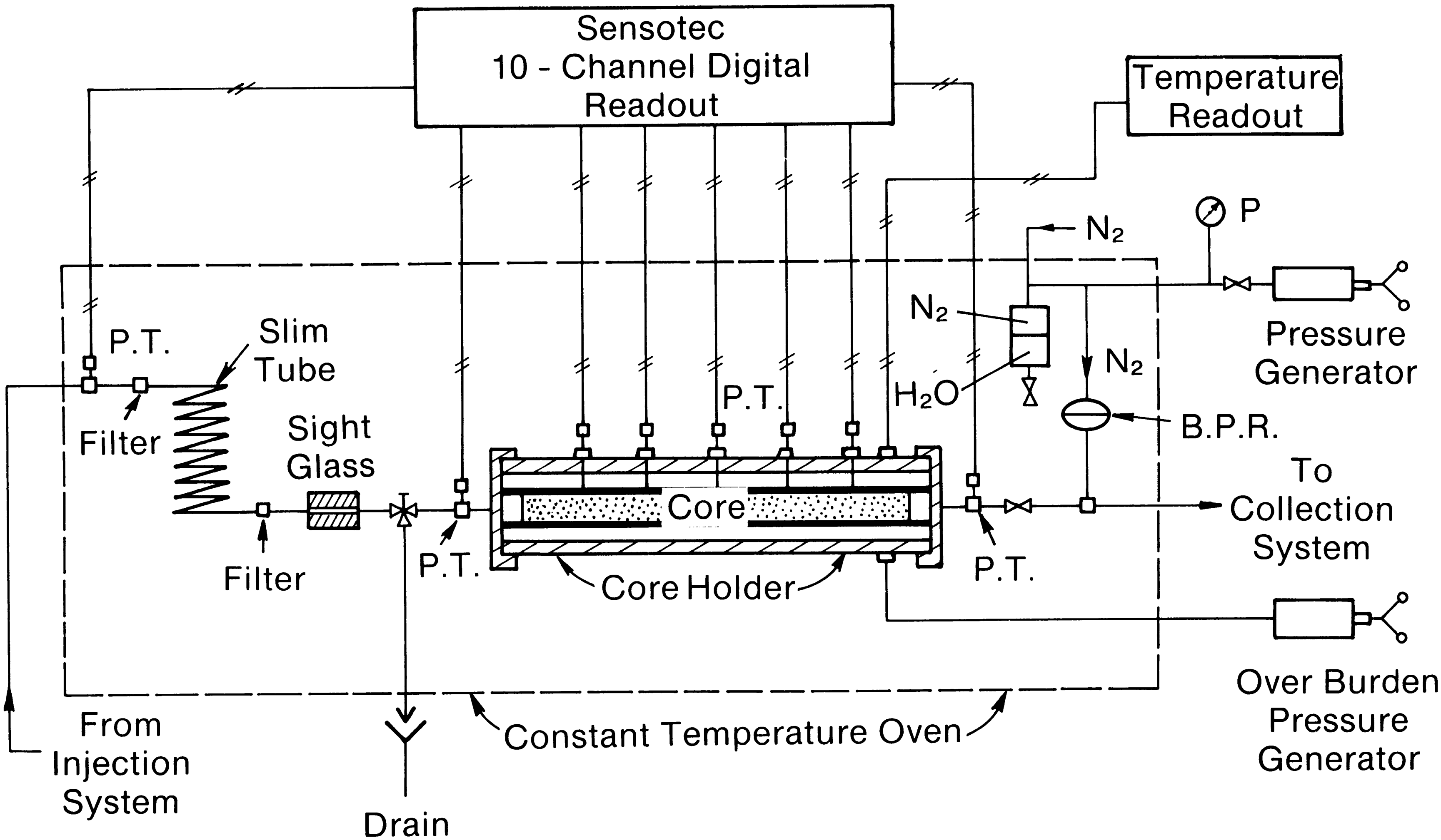

FIGURE 6. - Gas miscible coreflooding test apparatus.

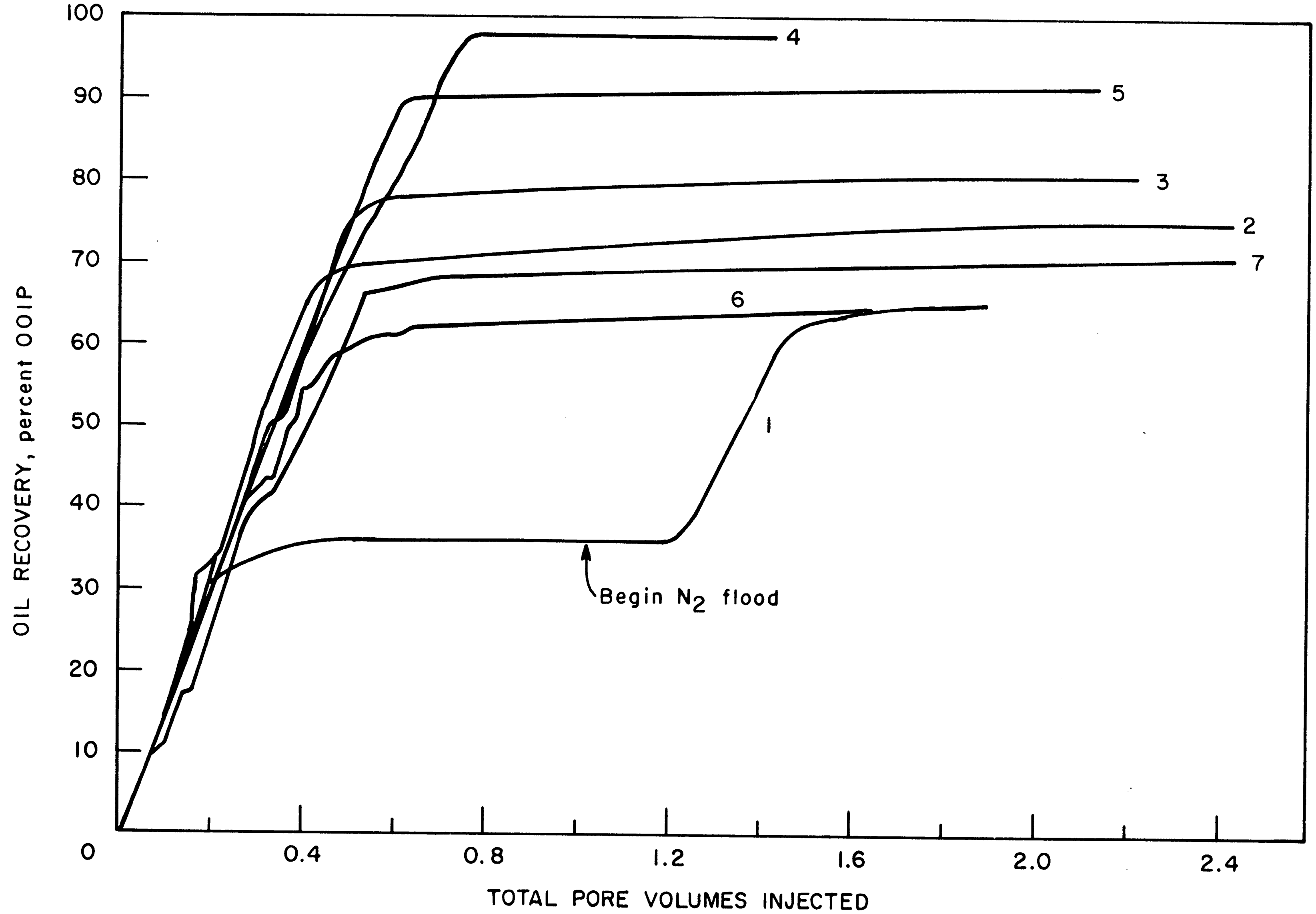

FIGURE 7. - Comparison of nitrogen core floods.

APPENDIX A - DETAILED TABULATION OF RESULTS FOR EACH COREFLOOD

Test No. 1

Waterflood and Tertiary Nitrogen Flood of Vertical Core Only

P.V. = 247.51 cc FVF.oil=1.4404 Sorw = 39.58 %
TEF,oil=1.1284 FVF.H2O=1.0316 Press.= 6000 psig
TEF,H2O=1.0469 OOIP = 152.4 cc Temp. = 225 F
TEF,N2= 1.2569 Soi = 61.58 % Room T= 80 F avg.

Total Pore Volumes Inj.	Prod. Res. Oil cc	Oil Sat. %	Water Sat. %	Gas Sat. %	GOR cc/cc	GLR cc/cc	Recovery Efficiency %OOIP	
0.000	0.0	61.58	38.42	0.00	---	---	0.0	Begin
0.103	22.2	52.62	47.38	0.00	---	---	14.6	waterflood
0.205	47.7	42.32	57.68	0.00	---	---	31.3	
0.308	51.7	40.69	59.31	0.00	---	---	33.9	
0.411	54.4	39.58	60.42	0.00	---	---	35.7	
0.514	54.4	39.58	60.42	0.00	---	---	35.7	
0.617	54.4	39.58	60.42	0.00	---	---	35.7	
0.720	54.4	39.58	60.42	0.00	---	---	35.7	
0.823	54.4	39.58	60.42	0.00	---	---	35.7	
0.926	54.4	39.58	60.42	0.00	---	---	35.7	
1.027	54.4	39.58	60.42	0.00	---	---	35.7	Begin
1.032	54.4	39.58	60.42	0.00	0	0	35.7	N_2 flood
1.047	54.4	39.58	59.42	1.00	0	3	35.7	
1.061	54.4	39.58	58.25	2.17	0	13	35.7	
1.128	54.4	39.58	53.63	6.79	0	3	35.7	
1.196	54.4	39.58	49.00	11.42	0	4	35.7	
1.263	60.4	37.14	45.00	17.87	260	79	39.7	
1.331	73.0	32.07	41.66	26.26	205	107	47.9	
1.398	84.1	27.59	41.58	30.83	224	219	55.2	
1.432	92.0	24.39	41.58	34.03	229	229	60.4	
1.465	94.2	23.52	41.41	35.07	785	620	61.8	
1.498	95.6	22.94	41.37	35.69	1989	1808	62.7	
1.531	96.6	22.53	41.37	36.10	2870	2870	63.4	
1.576	97.3	22.24	41.37	36.39	4600	4600	63.9	
1.611	98.0	21.95	41.25	36.81	3998	2499	64.3	
1.628	98.0	21.95	41.21	36.85	*******	22000	64.3	
1.668	98.2	21.89	41.21	36.91	15899	15899	64.4	
1.701	98.5	21.77	41.21	37.02	11250	11250	64.6	
1.735	98.8	21.66	40.91	37.43	12245	2721	64.8	
1.769	98.8	21.66	40.91	37.43	0	0	64.8	
1.803	98.8	21.66	40.91	37.43	0	0	64.8	
1.837	98.8	21.66	40.91	37.43	0	0	64.8	
1.870	98.8	21.66	40.91	37.43	0	0	64.8	
1.880	98.8	21.66	40.91	37.43	0	0	64.8	

Test No. 2

Secondary Nitrogen Flood of Horizontal Core Only

P.V. = 250.82 cc FVF,oil=1.4404 Sorw = --- %
TEF,oil=1.1284 FVF,H2O=1.0316 Press.= 6000 psig
TEF,H2O=1.0469 OOIP = 147.9 cc Temp. = 225 F
TEF,N2= 1.2569 Soi = 58.98 % Room T= 80 F avg.

Pore Volumes Inj.	Prod. Res. Oil cc	Oil Sat. %	Water Sat. %	Gas Sat. %	GOR cc/cc	GLR cc/cc	Recovery Efficiency %OIP
0.000	0.0	58.98	41.02	0.00	0	0	0.0
0.016	2.9	57.83	41.02	1.15	171	171	1.9
0.025	3.9	57.43	41.02	1.55	150	150	2.6
0.044	7.9	55.82	41.02	3.16	114	114	5.4
0.058	11.1	54.56	41.02	4.42	133	133	7.5
0.070	15.0	53.01	41.02	5.97	118	118	10.1
0.091	18.1	51.74	41.02	7.24	135	135	12.3
0.107	21.9	50.25	41.02	8.73	136	136	14.8
0.123	26.4	48.47	41.02	10.51	122	122	17.8
0.139	30.5	46.81	41.02	12.17	112	112	20.6
0.156	34.3	45.31	41.02	13.67	118	118	23.2
0.172	38.9	43.47	41.02	15.51	130	130	26.3
0.189	42.9	41.87	41.02	17.11	124	124	29.0
0.205	49.7	39.17	41.02	19.81	116	116	33.6
0.222	51.6	38.42	41.02	20.56	132	132	34.9
0.239	56.5	36.47	41.02	22.51	138	138	38.2
0.255	61.4	34.52	41.02	24.46	114	114	41.5
0.272	65.4	32.91	41.02	26.07	122	122	44.2
0.288	69.1	31.41	41.02	27.57	121	121	46.7
0.305	75.8	28.77	41.02	30.21	135	135	51.2
0.321	79.8	27.17	41.02	31.81	183	183	53.9
0.338	82.8	25.96	41.02	33.02	240	240	56.0
0.354	86.1	24.64	41.02	34.34	271	271	58.2
0.373	89.9	23.15	41.02	35.83	340	340	60.8
0.388	93.3	21.77	41.02	37.21	270	270	63.1
0.405	96.1	20.68	41.02	38.30	314	314	64.9
0.421	99.0	19.53	41.02	39.45	464	464	66.9
0.438	100.1	19.07	41.02	39.91	1489	1489	67.7
0.455	101.4	18.55	41.02	40.43	1232	1232	68.5
0.471	102.0	18.32	41.02	40.66	2382	2382	68.9
0.506	102.7	18.03	41.02	40.95	4300	4300	69.4
0.538	103.3	17.80	41.02	41.18	3234	3234	69.8
0.571	103.6	17.69	41.02	41.29	9720	9720	70.0
0.604	103.9	17.57	41.02	41.41	10600	10600	70.2
0.737	104.7	17.23	41.02	41.75	13365	13365	70.8
0.869	105.4	16.94	41.02	42.04	18800	18800	71.3
1.001	106.6	16.48	41.02	42.50	10524	10524	72.1
1.134	107.6	16.08	41.02	42.90	11970	11970	72.7
1.267	108.2	15.85	41.02	43.13	22900	22900	73.1
1.400	108.5	15.74	41.02	43.24	43259	43259	73.3
1.533	108.9	15.56	41.02	43.42	27759	27759	73.6
1.665	109.5	15.33	41.02	43.65	21500	21500	74.0
1.798	109.8	15.22	40.98	43.80	41498	27666	74.2
1.931	110.3	14.99	40.98	44.03	20920	20920	74.6
2.063	110.8	14.82	40.98	44.20	27933	27933	74.9
2.196	110.9	14.76	40.98	44.26	88280	88280	75.0
2.400	111.1	14.70	40.98	44.32	126000	126000	75.1

Test No. 3

Secondary Nitrogen Flood of Vertical Core Only

P.V. = 251.97 cc FVF,oil=1.4404 Sorw = --- %
TEF,oil=1.1284 FVF,H2O=1.0316 Press.= 6000 psig
TEF,H2O=1.0469 OOIP = 149.8 cc Temp. = 225 F
TEF,N2= 1.2569 Soi = 59.45 % Room T= 80 F avg.

Pore Volumes Inj.	Prod. Res. Oil cc	Oil Sat. %	Water Sat. %	Gas Sat. %	GOR cc/cc	GLR cc/cc	Recovery Efficiency %OIP
0.000	0.0	59.45	40.55	0.00	0	0	0.0
0.033	6.3	56.93	40.55	2.52	151	151	4.2
0.059	11.8	54.76	40.55	4.69	137	137	7.9
0.075	14.0	53.90	40.55	5.55	134	134	9.3
0.091	17.3	52.59	40.55	6.86	106	106	11.5
0.108	21.3	50.99	40.55	8.46	171	171	14.2
0.125	25.4	49.39	40.55	10.06	110	110	16.9
0.142	29.4	47.79	40.55	11.66	131	131	19.6
0.159	33.7	46.07	40.55	13.38	119	119	22.5
0.176	37.7	44.47	40.55	14.98	131	131	25.2
0.192	41.5	42.99	40.55	16.46	131	131	27.7
0.205	44.7	41.73	40.55	17.72	127	127	29.8
0.222	48.7	40.13	40.55	19.32	142	142	32.5
0.239	53.6	38.18	40.55	21.27	123	123	35.8
0.255	58.8	36.13	40.55	23.32	120	120	39.2
0.272	62.8	34.53	40.55	24.92	118	118	41.9
0.288	66.8	32.93	40.55	26.52	148	148	44.6
0.305	72.3	30.75	40.55	28.70	87	87	48.3
0.321	75.2	29.61	40.55	29.84	119	119	50.2
0.338	75.8	29.38	40.55	30.07	59	59	50.6
0.354	76.6	29.04	40.55	30.41	214	214	51.2
0.371	82.5	26.69	40.55	32.76	119	119	55.1
0.389	87.0	24.92	40.55	34.53	124	124	58.1
0.412	92.3	22.81	40.55	36.64	145	145	61.6
0.421	95.1	21.72	40.55	37.73	90	90	63.5
0.438	99.4	20.01	40.55	39.44	118	118	66.3
0.443	100.7	19.49	40.55	39.96	127	127	67.2
0.466	106.6	17.15	40.55	42.30	134	134	71.2
0.480	109.8	15.89	40.55	43.56	214	214	73.3
0.495	112.2	14.92	40.55	44.53	327	327	74.9
0.519	114.8	13.89	40.55	45.56	609	609	76.6
0.537	115.4	13.66	40.55	45.79	3108	3108	77.0
0.554	115.8	13.49	40.55	45.96	3689	3689	77.3
0.583	116.4	13.26	40.55	46.19	4968	4968	77.7
0.606	116.7	13.15	40.55	46.30	8569	8569	77.9
0.770	117.7	12.75	40.55	46.70	16786	16786	78.6
1.056	119.0	12.23	40.55	47.22	21074	21074	79.4
1.297	120.1	11.77	40.55	47.68	20249	20249	80.2
1.373	120.3	11.72	40.55	47.73	54799	54799	80.3
1.897	121.0	11.43	40.55	48.02	77000	77000	80.8
2.079	121.3	11.32	40.55	48.13	64779	64779	81.0
2.106	121.3	11.32	40.55	48.13	ERR	ERR	81.0
2.194	121.3	11.32	40.55	48.13	ERR	ERR	81.0

Test No. 4

Secondary Nitrogen Flood of Slim Tube Only

P.V. = 220.42 cc	FVF,oil=1.4404	Sorw = --- %
TEF,oil=1.1284	FVF,H2O=1.0316	Press.= 6000 psig
TEF,H2O=1.0469	OOIP = 167.2 cc	Temp. = 225 F
TEF,N2= 1.2569	Soi = 75.87 %	Room T= 80 F avg.

Pore Volumes Inj.	Prod. Res. Oil cc	Oil Sat. %	Water Sat. %	Gas Sat. %	GOR cc/cc	GLR cc/cc	Recovery Efficiency %OIP
0.000	0.0	75.87	24.13	0.00	0	0	0.0
0.029	3.5	74.30	24.13	1.57	209	209	2.1
0.064	11.2	70.77	24.13	5.10	153	153	6.7
0.097	19.2	67.18	24.13	8.69	155	155	11.5
0.150	32.4	61.17	24.13	14.70	153	153	19.4
0.160	35.3	59.86	24.13	16.01	158	158	21.1
0.197	47.1	54.50	24.13	21.37	151	151	28.2
0.238	58.0	49.53	24.13	26.34	151	151	34.7
0.272	65.4	46.20	24.13	29.67	147	147	39.1
0.288	68.9	44.63	24.04	31.33	174	161	41.2
0.309	73.9	42.35	24.04	33.62	147	147	44.2
0.347	82.5	38.43	24.04	37.54	154	154	49.4
0.385	91.6	34.31	24.04	41.65	162	162	54.8
0.423	100.3	30.39	24.04	45.58	155	155	59.9
0.460	108.3	26.73	23.94	49.33	151	146	64.8
0.499	116.7	22.94	23.94	53.12	158	158	69.8
0.537	123.6	19.80	23.94	56.26	157	157	73.9
0.575	129.2	17.25	23.85	58.90	158	150	77.3
0.610	134.5	14.83	23.85	61.32	150	150	80.4
0.648	141.3	11.76	23.85	64.39	140	140	84.5
0.686	149.9	7.84	23.76	68.40	152	147	89.7
0.719	157.9	4.25	23.71	72.04	156	153	94.4
0.760	163.3	1.77	23.66	74.57	455	443	97.7
0.766	163.5	1.70	23.66	74.64	3879	3879	97.8
0.771	163.5	1.70	23.62	74.68	ERR	3429	97.8
0.778	163.5	1.70	23.62	74.68	ERR	ERR	97.8
0.784	163.6	1.67	23.62	74.72	8279	8279	97.8
0.791	163.6	1.63	23.57	74.80	9057	3019	97.8
0.801	163.6	1.63	23.57	74.80	ERR	ERR	97.8
0.812	163.6	1.63	23.57	74.80	ERR	ERR	97.8
0.826	163.6	1.63	23.57	74.80	ERR	ERR	97.8
0.839	163.6	1.63	23.57	74.80	ERR	ERR	97.8
0.857	163.6	1.63	23.57	74.80	ERR	ERR	97.8
0.888	163.6	1.63	23.57	74.80	ERR	ERR	97.8
0.919	163.6	1.63	23.57	74.80	ERR	ERR	97.8
0.951	163.6	1.63	23.47	74.89	ERR	10500	97.8
0.985	163.6	1.63	23.43	74.94	ERR	20019	97.8
0.998	163.6	1.63	23.43	74.94	ERR	ERR	97.8
1.026	163.6	1.63	23.43	74.94	ERR	ERR	97.8
1.055	163.6	1.63	23.43	74.94	ERR	ERR	97.8
1.080	163.6	1.63	23.43	74.94	ERR	ERR	97.8
1.109	163.6	1.63	23.43	74.94	ERR	ERR	97.8
1.137	163.6	1.63	23.43	74.94	ERR	ERR	97.8
1.166	163.6	1.63	23.43	74.94	ERR	ERR	97.8
1.194	163.6	1.63	23.43	74.94	ERR	ERR	97.8
1.243	163.6	1.63	23.43	74.94	ERR	ERR	97.8
1.249	163.6	1.63	23.43	74.94	ERR	ERR	97.8
1.261	163.6	1.63	23.43	74.94	ERR	ERR	97.8
1.289	163.6	1.63	23.43	74.94	ERR	ERR	97.8
1.445	163.6	1.63	23.43	74.94	ERR	ERR	97.8

Test No. 5

Secondary Nitrogen Flood of Slim Tube + Vertical Core

P.V. = 470.04 cc	FVF,oil=1.4404	Sorw = --- %	
TEF,oil=1.1284	FVF,H2O=1.0316	Press.= 6000 psig	
TEF,H2O=1.0469	OOIP = 308.2 cc	Temp. = 225 F	
TEF,N2= 1.2569	Soi = 65.57 %	Room T= 80 F avg.	

Pore Volumes Inj.	Prod. Res. Oil cc	Oil Sat. %	Water Sat. %	Gas Sat. %	GOR cc/cc	GLR cc/cc	Recovery Efficiency %OIP
0.000	0.0	65.57	34.43	0.00	0	0	0.0
0.028	5.0	64.50	34.39	1.12	172	163	1.6
0.059	18.9	61.56	34.39	4.06	131	131	6.1
0.094	34.6	58.22	34.39	7.40	133	133	11.2
0.130	50.3	54.88	34.39	10.74	131	131	16.3
0.174	70.0	50.68	34.39	14.94	134	134	22.7
0.198	81.1	48.32	34.39	17.30	130	130	26.3
0.236	98.5	44.61	34.39	21.00	132	132	32.0
0.268	116.4	40.81	34.39	24.80	126	126	37.8
0.289	127.9	38.36	34.39	27.26	134	134	41.5
0.323	143.6	35.02	34.39	30.60	127	127	46.6
0.344	153.3	32.96	34.39	32.65	142	142	49.7
0.353	158.4	31.86	34.39	33.75	136	136	51.4
0.397	180.2	27.23	34.39	38.38	137	137	58.5
0.438	198.3	23.37	34.39	42.24	145	145	64.4
0.467	210.3	20.83	34.36	44.81	145	143	68.2
0.503	226.4	17.40	34.36	48.24	141	141	73.5
0.538	242.0	14.09	34.36	51.55	146	146	78.5
0.556	250.1	12.37	34.36	53.26	150	150	81.1
0.574	258.1	10.66	34.36	54.98	234	234	83.7
0.591	266.2	8.94	34.36	56.70	235	235	86.4
0.607	269.9	8.14	34.36	57.49	475	475	87.6
0.612	271.4	7.84	34.36	57.80	349	349	88.0
0.617	275.1	7.04	34.36	58.60	704	704	89.3
0.644	276.3	6.79	34.36	58.84	1999	1999	89.6
0.662	277.3	6.58	34.36	59.06	2870	2870	90.0
0.680	277.7	6.49	34.34	59.17	8832	6624	90.1
0.695	278.0	6.43	34.34	59.23	8899	8899	90.2
0.710	278.3	6.37	34.34	59.29	9349	9349	90.3
0.727	278.3	6.37	34.34	59.29	ERR	ERR	90.3
0.742	278.6	6.30	34.34	59.35	9559	9559	90.4
0.760	278.9	6.24	34.34	59.41	11139	11139	90.5
0.773	279.1	6.18	34.34	59.48	9049	9049	90.6
0.784	279.1	6.18	34.34	59.48	ERR	ERR	90.6
0.795	279.1	6.18	34.34	59.48	ERR	ERR	90.6
0.795	279.1	6.18	34.34	59.48	ERR	ERR	90.6
0.831	279.4	6.12	34.34	59.54	27574	27574	90.7
1.164	280.7	5.84	34.32	59.84	42188	37969	91.1
1.245	281.0	5.78	34.32	59.90	49124	49124	91.2
1.280	281.3	5.72	34.32	59.96	22374	22374	91.3
1.397	281.3	5.72	34.32	59.96	ERR	ERR	91.3
1.593	281.3	5.72	34.32	59.96	ERR	ERR	91.3
1.701	281.5	5.69	34.28	60.03	124947	41649	91.3
1.802	281.5	5.69	34.23	60.08	*******	59599	91.3
2.054	281.5	5.69	34.23	60.08	ERR	ERR	91.3
2.102	281.5	5.69	34.23	60.08	ERR	ERR	91.3
2.149	281.5	5.69	34.21	60.10	ERR	50649	91.3

Test No. 6

Secondary Nitrogen + 0.1 PV 0.1% Foamer Flood of Horizontal Core

P.V. = 252.32 cc   FVF,oil=1.4404   Sorw = --- %
TEF,oil=1.1284   FVF,H2O=1.0316   Press.= 6000 psig
TEF,H2O=1.0469   OOIP = 155.3 cc   Temp. = 225 F
TEF,N2= 1.2569   Soi = 61.53 %   Room T= 80 F avg.

Pore Volumes Inj.	Prod. Res. Oil cc	Oil Sat. %	Water Sat. %	Gas Sat. %	GOR cc/cc	GLR cc/cc	Recovery Efficiency %OIP	
0.000	0.0	61.53	38.47	0.00	0	0	0.0	Start
0.036	5.2	59.47	41.85	-1.33	46	39	3.3	foamer
0.096	21.8	52.91	47.83	-0.74	17	17	14.0	
0.102	24.3	51.88	48.40	-0.28	5	5	15.7	Stop
0.102	24.3	51.88	48.40	-0.28	ERR	ERR	15.7	Start
0.144	31.1	49.20	48.40	2.40	5	5	20.0	N2
0.171	48.4	42.35	48.40	9.25	64	64	31.2	
0.204	50.7	41.44	48.40	10.16	30	30	32.7	
0.238	55.9	39.38	48.16	12.46	104	89	36.0	
0.271	62.2	36.87	47.75	15.38	74	60	40.1	
0.304	64.8	35.84	45.79	18.37	35	10	41.8	
0.321	66.5	35.16	45.05	19.79	14	6	42.9	
0.337	66.8	35.04	44.23	20.73	239	22	43.0	
0.355	71.4	33.22	43.99	22.80	21	17	46.0	
0.369	75.8	31.50	43.66	24.84	32	25	48.8	
0.388	78.4	30.48	43.17	26.36	21	12	50.5	
0.403	84.0	28.25	42.80	28.95	99	80	54.1	
0.421	84.7	27.96	42.76	29.28	19	16	54.6	
0.436	86.0	27.45	42.64	29.91	210	157	55.4	
0.453	88.3	26.54	42.56	30.91	499	443	56.9	
0.475	90.3	25.74	42.56	31.71	713	713	58.2	
0.486	91.2	25.39	42.56	32.05	499	499	58.7	
0.520	92.5	24.88	42.52	32.60	2110	1899	59.6	
0.535	93.0	24.65	42.47	32.87	2749	2199	59.9	
0.551	93.6	24.42	42.43	33.14	2499	1999	60.3	
0.567	93.9	24.31	42.43	33.26	6749	6749	60.5	
0.584	94.6	24.02	42.39	33.58	139	116	61.0	
0.600	94.6	24.02	42.39	33.58	ERR	ERR	61.0	
0.617	94.9	23.91	42.39	33.70	2749	2749	61.1	
0.633	95.8	23.57	42.39	34.04	2749	2749	61.7	
0.649	96.1	23.45	42.39	34.15	1899	1899	61.9	
0.666	96.2	23.40	42.39	34.21	7299	7299	62.0	
0.682	96.4	23.34	42.39	34.27	10899	10899	62.1	
0.715	96.7	23.23	42.39	34.38	13999	13999	62.3	
0.748	96.9	23.11	42.39	34.50	5249	5249	62.4	
0.781	97.1	23.05	42.39	34.55	25499	25499	62.5	
0.814	97.2	23.00	42.39	34.61	21499	21499	62.6	
0.847	97.4	22.94	42.39	34.67	27499	27499	62.7	
0.886	97.4	22.94	42.39	34.67	ERR	ERR	62.7	
0.918	97.9	22.71	42.39	34.90	4374	4374	63.1	
0.935	97.9	22.71	42.39	34.90	ERR	ERR	63.1	
0.946	97.9	22.71	42.39	34.90	ERR	ERR	63.1	
0.979	97.9	22.71	42.39	34.90	ERR	ERR	63.1	
1.012	97.9	22.71	42.39	34.90	ERR	ERR	63.1	
1.031	97.9	22.71	42.39	34.90	ERR	ERR	63.1	
1.045	97.9	22.71	42.39	34.90	ERR	ERR	63.1	

Test No. 6 - continued

Secondary Nitrogen + 0.1 PV 0.1% Foamer Flood of Horizontal Core
(Continued)

P.V. = 252.32 cc	FVF,oil=1.4404	Sorw = --- %
TEF,oil=1.1284	FVF,H2O=1.0316	Press.= 6000 psig
TEF,H2O=1.0469	OOIP = 155.3 cc	Temp. = 225 F
TEF,N2= 1.2569	Soi = 61.53 %	Room T= 80 F avg.

Pore Volumes Inj.	Prod. Res. Oil cc	Oil Sat. %	Water Sat. %	Gas Sat. %	GOR cc/cc	GLR cc/cc	Recovery Efficiency %OIP
1.078	97.9	22.71	42.39	34.90	ERR	ERR	63.1
1.111	97.9	22.71	42.39	34.90	ERR	ERR	63.1
1.144	97.9	22.71	42.39	34.90	ERR	ERR	63.1
1.178	97.9	22.71	42.39	34.90	ERR	ERR	63.1
1.376	99.4	22.14	42.35	35.51	9949	9044	64.0
1.407	99.4	22.14	42.35	35.51	ERR	ERR	64.0
1.440	99.5	22.08	42.35	35.57	22999	22999	64.1
1.473	99.7	22.03	42.35	35.62	21999	21999	64.2
1.506	99.8	21.97	42.35	35.68	22799	22799	64.3
1.538	100.3	21.80	42.35	35.85	7566	7566	64.6
1.571	100.3	21.80	42.35	35.85	ERR	ERR	64.6
1.604	100.4	21.74	42.35	35.91	21499	21499	64.7
1.637	100.4	21.74	42.35	35.91	ERR	ERR	64.7

Test No. 7

Secondary Nitrogen + 0.1 PV 1.0% Foamer Flood of Vertical Core Only

P.V. = 256.16 cc FVF,oil=1.4404 Sorw = --- %
TEF,oil=1.1284 FVF,H2O=1.0316 Press.= 6000 psig
TEF,H2O=1.0469 OOIP = 155.6 cc Temp. = 225 F
TEF,N2= 1.2569 Soi = 60.73 % Room T= 80 F avg.

Pore Volumes Inj.	Prod. Res. Oil cc	Oil Sat. %	Water Sat. %	Gas Sat. %	GOR cc/cc	GLR cc/cc	Recovery Efficiency %OIP	
0.000	0.0	60.73	39.27	0.00	0	0	0.0	Start
0.024	4.8	58.87	41.48	-0.35	79	69	3.1	foamer
0.038	8.6	57.36	42.87	-0.23	86	86	5.6	
0.051	12.0	56.06	44.14	-0.21	82	82	7.7	Stop
0.102	15.8	54.54	49.25	-3.79	55	55	10.2	Start
0.118	19.4	53.14	49.25	-2.39	103	103	12.5	N2
0.134	23.3	51.62	49.25	-0.87	88	88	15.0	
0.145	25.8	50.66	49.25	0.09	81	81	16.6	
0.161	25.8	50.66	49.25	0.09	ERR	ERR	16.6	
0.178	30.2	48.92	49.25	1.83	105	105	19.4	
0.195	35.0	47.07	49.25	3.69	96	96	22.5	
0.211	40.3	44.99	49.25	5.77	84	84	25.9	
0.227	44.7	43.30	49.25	7.46	62	62	28.7	
0.276	58.6	37.84	49.25	12.91	95	95	37.7	
0.310	62.7	36.27	47.68	16.05	87	36	40.3	
0.342	64.1	35.71	45.54	18.75	74	12	41.2	
0.375	70.3	33.29	43.81	22.90	22	11	45.2	
0.408	75.3	31.32	42.88	25.80	77	47	48.4	
0.440	81.8	28.79	42.36	28.85	49	38	52.6	
0.473	87.9	26.43	41.88	31.69	108	84	56.5	
0.505	95.2	23.56	41.76	34.68	88	83	61.2	
0.513	97.1	22.83	41.72	35.45	91	85	62.4	
0.538	102.6	20.69	41.59	37.71	89	82	65.9	
0.570	103.6	20.30	41.47	38.23	1220	854	66.6	
0.604	103.9	20.19	41.31	38.50	14627	4876	66.8	
0.636	104.4	19.96	41.31	38.72	7334	7334	67.1	
0.669	105.1	19.68	41.31	39.01	6239	6239	67.6	
0.701	105.7	19.46	41.27	39.27	3976	3181	68.0	
0.740	105.7	19.46	41.03	39.51	ERR	2006	68.0	
0.798	105.9	19.40	40.99	39.61	30398	15199	68.1	
0.831	106.3	19.23	40.91	39.86	6465	3879	68.3	
0.863	106.4	19.18	40.83	39.99	21797	7266	68.4	
0.896	106.4	19.18	40.75	40.08	ERR	10749	68.4	
0.928	106.9	19.01	40.67	40.32	7665	4599	68.7	
0.961	107.0	18.95	40.59	40.46	22897	7632	68.8	
0.994	107.0	18.95	40.51	40.54	ERR	12499	68.8	
1.026	107.3	18.84	40.43	40.73	15083	7541	69.0	
1.067	107.3	18.84	40.31	40.86	ERR	6579	69.0	
1.092	107.3	18.84	40.31	40.86	ERR	ERR	69.0	
1.125	107.3	18.84	40.27	40.90	ERR	22779	69.0	
1.165	107.3	18.84	40.27	40.90	ERR	ERR	69.0	
1.190	107.3	18.84	40.27	40.90	ERR	ERR	69.0	
1.222	107.3	18.84	40.23	40.94	*******	22229	69.0	
1.255	107.5	18.78	40.23	40.99	19049	19049	69.1	
1.484	107.7	18.67	40.14	41.19	83518	41759	69.3	
1.614	108.8	18.28	40.10	41.62	8572	7500	69.9	
1.760	109.0	18.16	39.86	41.97	49931	12483	70.1	
2.450	110.0	17.77	39.70	42.53	65721	41823	70.7	

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