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Status Report

COMPARISON OF THREE-PHASE RELATIVE PERMEABILITY--EXPERIMENTAL DATA VERSUS PREDICTED DATA FROM AVAILABLE MODELS

Project BE9, Tasks 1 and 3 in FY86 Annual Plan

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SUMMARY

The ultimate objective of project BE9 is to identify the mechanisms and improve the understanding of multiphase flow in porous media. In this report, the work accomplished in Tasks 1 and 3 FY86 is presented. Task 1 involved the development of procedures for accurate measurement of three-phase relative permeability for Berea cores at low and high pressures using x-ray/microwave apparatus. Task 3 concerned the evaluation of a three-phase relative permeability model (TPKR) and comparison of the model and experimental data developed in project BE9 with previously developed models and published experimental data.

The report is divided into three sections. The first section presents a procedure to carry out precise determination of three-phase relative permeability steady- and unsteady-state measurements using x-ray/microwave apparatus for cylindrical cores at high pressures. The second part of the report gives a comparison of the experimental results obtained by this investigation with the experimental results obtained by previous investigators. The third section of this report presents a comparison of experimental results obtained by this investigation with the results predicted by four previously published models.

PROCEDURE TO CARRY OUT PRECISE DETERMINATION OF THREE-PHASE RELATIVE PERMEABILITY USING X-RAY/MICROWAVE APPARATUS FOR CYLINDRICAL CORES AT LOW AND HIGH PRESSURES

A description of the x-ray/microwave apparatus, calibration, testing, and operational procedures was previously reported.[1] The modifications to the apparatus for the measurement of saturations in cylindrical cores at high pressure are described below.

A non-metallic core holder was designed and tested during FY86. The non-metallic material is needed to allow the use of microwaves for the measurement of water saturation since microwaves are reflected by all metals. The design calls for each individual core to be wrapped with fiberglass. This fiberglass material has limitations on maximum net confining pressure (2,000 psi @ 212° F). Another limitation of this type of core holder is that no pressure taps can be provided since the encasing material is not machineable. The original design was modified to allow for the use of overburden pressures by encasing the core with heat shrinkable tubing. Testing of the new design showed that the heat shrinkable tubing breaks at high temperatures. A different type of casing material is being investigated.

The microwave system was redesigned to allow for the computation of reflected power due to the use of cylindrical cores. The standard gain receiving and transmitting antennas were replaced by lens-corrected antennas. The lens-corrected antennas reduce the amount of microwaves reflected from the surface of the coreholder and focus the microwave beam to a small area of high intensity. The area of investigation with the lens-corrected microwave horns is 0.6 in.^{2} at a focal length of 6 in. This feature allows for the use of larger high porosity cores than with the standard gain antennas.

For pressures to 5,000 psi, a Hassler type uniaxial carbon fiber core holder with four pressure taps was ordered (5,000 psi at 260° F).

COMPARISON OF ISOPERMS OBTAINED BY THIS INVESTIGATION WITH ISOPERMS OBTAINED BY PREVIOUS INVESTIGATORS

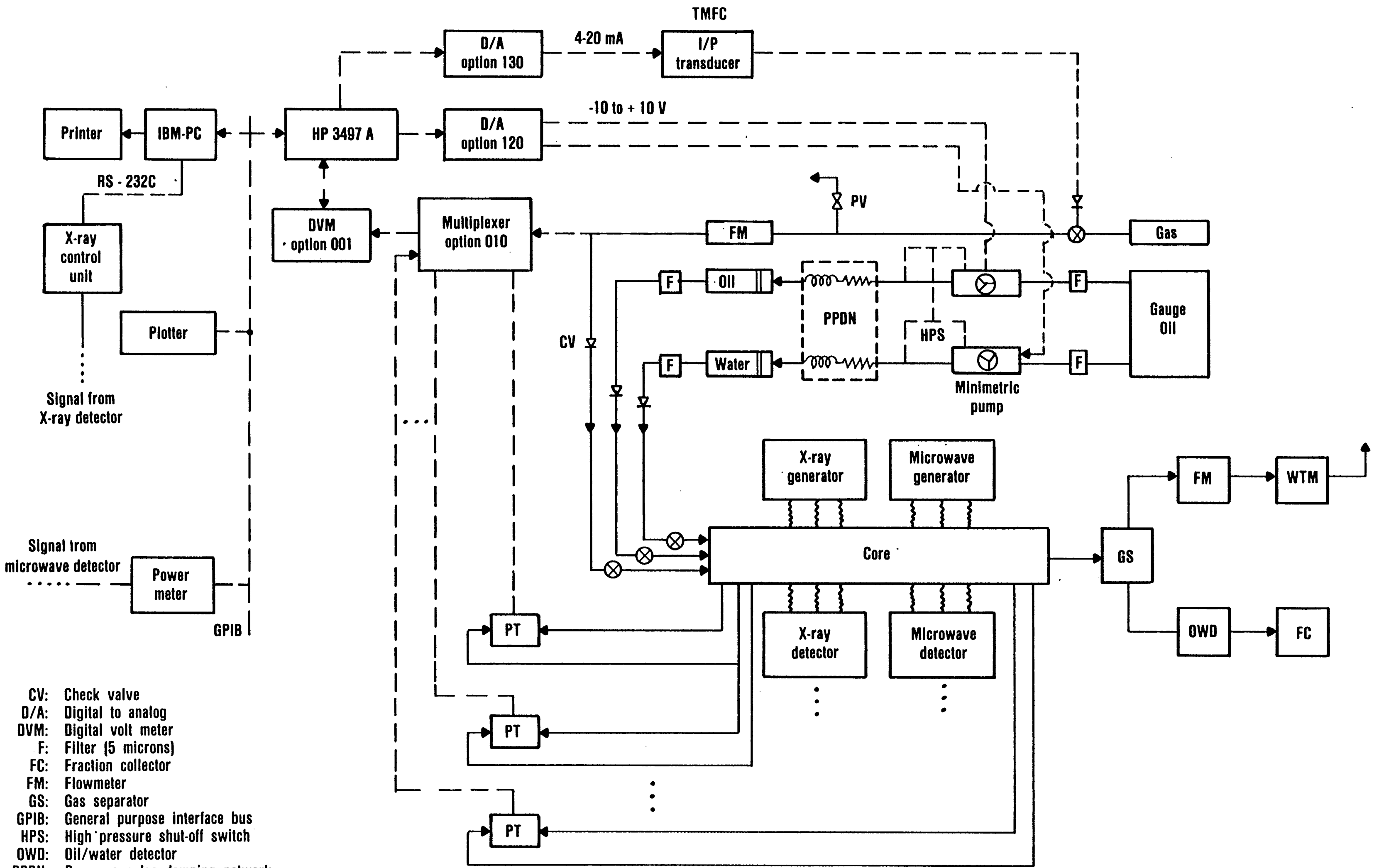
More than 50 three-phase relative permeability points have been measured on rectangular Berea sandstone cores (1.5 in. height, 3/4 in. width, and 6 in. length) at ambient conditions by use of the steady-state method. Brine (10,000 ppm NaCl), Soltrol 220 (refined), and nitrogen (saturated with brine and oil) were injected simultaneously, and saturation profiles were obtained by the x-ray/microwave absorption technique. Figure 1 is a schematic diagram of the experimental apparatus.

The flow rates of the three fluids were varied--0 to 6 ml/min for the brine and oil and 50 to 200 cm^3/min for the nitrogen--so as to attain a wide range of saturations and saturation histories.

The pressure drop was measured at four intervals along the core. The pressure drop across the center of the core was used in calculating three-phase relative permeability since the fluid saturation was evenly distributed across the center of the core. The saturations were measured at steady-state conditions with all fluids flowing. This procedure eliminated errors in saturation resulting from redistribution and loss of fluids with release of pressure and capillary end effects.

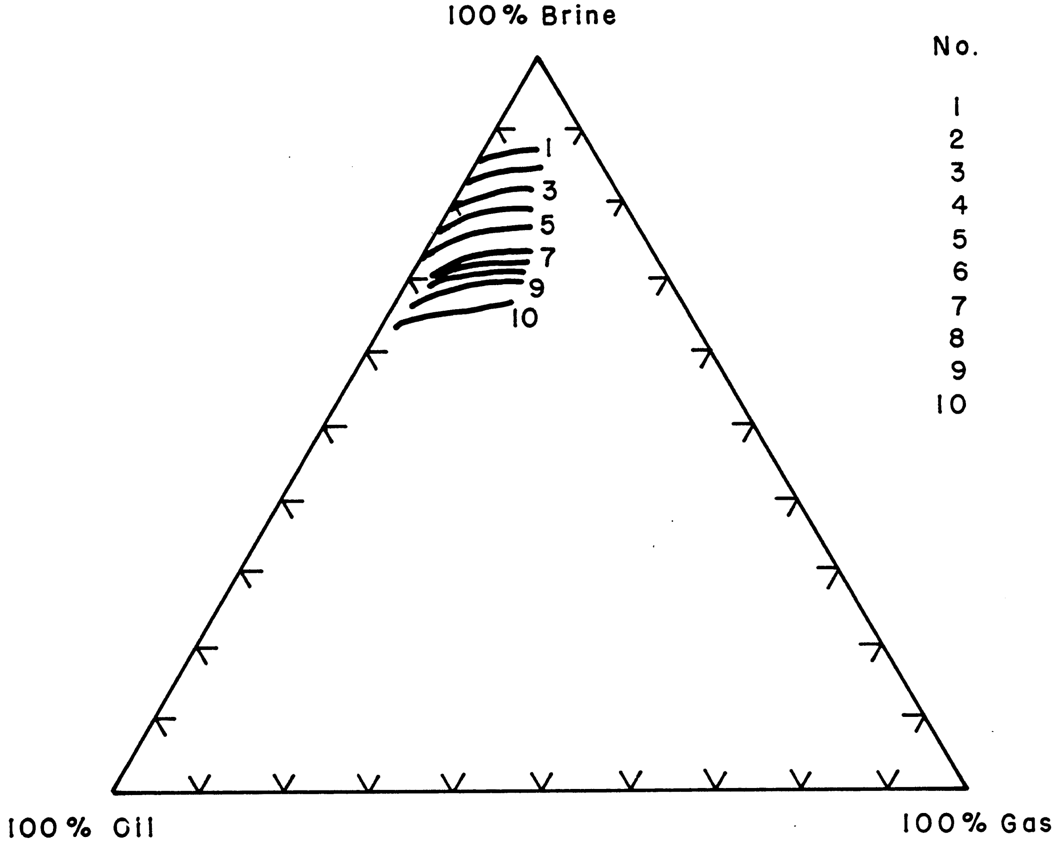
The three-phase relative permeability data obtained have been plotted by the graphical contouring method developed at NIPER,[2] and the results are shown in figures 2 through 4. Owing to the limited number of data points available, no attempt was made to study the effect of saturation history (hysteresis effect) on the relative permeability. Further work is underway to establish the reproducibility of the experimental data. A study of the extent of hysteresis in the three-phase relative permeability isoperms will be conducted after more experimental data points are available.

When plotted on a ternary diagram with oil, water, and gas saturation at the apices,[2] the shape of the isoperms of a phase are either convex, concave, or linear towards the 100 percent apex of that phase. To indicate what each behavior means, consider the oil isoperms. An oil isoperm convex toward the 100 percent oil apex indicates that the oil relative permeability is lower when both brine and gas are present than when either brine or gas alone is



CV: Check valve
D/A: Digital to analog
DVM: Digital volt meter
F: Filter (5 microns)
FC: Fraction collector
FM: Flowmeter
GS: Gas separator
GPIB: General purpose interface bus
HPS: High pressure shut-off switch
OWD: Oil/water detector
PPDN: Pressure pulse damping network
PT: Pressure transducer
PV: Purge/safety valve
TMFC: Thermal mass flow controller
WTM: Wet test meter

FIGURE 1. - Schematic diagram of the three-phase relative permeability apparatus.



No.	K_r (%)
1	60.0
2	50.0
3	40.0
4	30.0
5	20.0
6	10.0
7	7.5
8	5.5
9	3.5
10	1.5

FIGURE 2. - Brine isoperms.

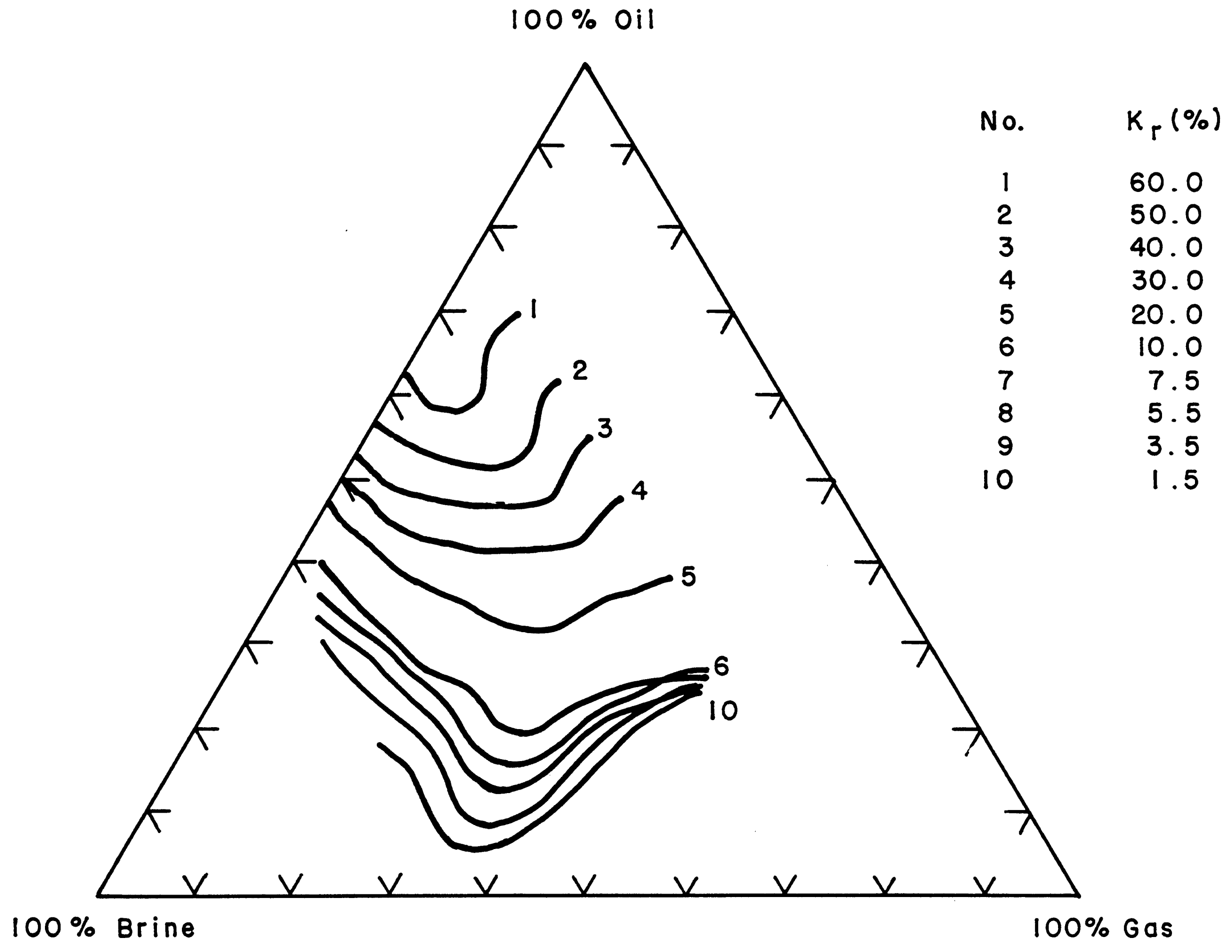


FIGURE 3. - Oil isoperms.

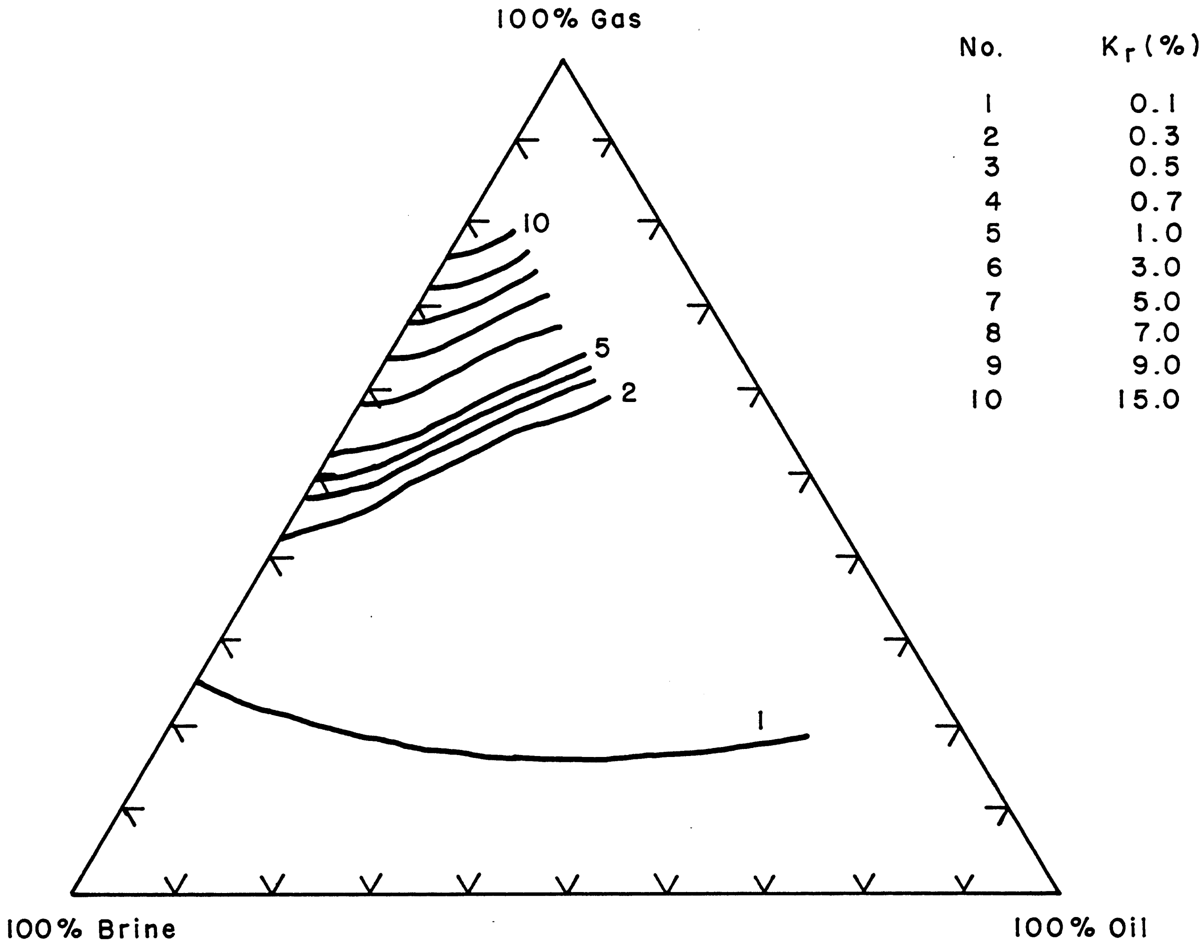


FIGURE 4. - Gas isoperms.

present. A linear oil isoperm indicates that the oil relative permeability is only a function of its own saturation; thus, it is independent of the ratio of brine and gas saturations. A concave oil isoperm towards the 100 percent oil apex would indicate higher oil relative permeabilities when both gas and brine are present than in the presence of brine or gas alone. A similar explanation can be given for gas and water isoperms.

The shape of the oil isoperm obtained in this study (Fig. 3) is concave toward the 100 percent oil apex. Similar results were reported by Leverett and Lewis,[3] Reid,[4] Caudle et al.,[5] Holmgren and Morse,[6] Corey et al.,[7] Donaldson and Dean,[8] Van Spronsen,[9] and Saraf and Batycky.[10] The oil isoperm's behavior thus indicates that the oil relative permeability is a function of all three saturations. The gas isoperms (Fig. 4) exhibit a concave shape toward the 100 percent gas apex. The linear brine relative permeability isoperms (Fig. 2) indicate that the brine permeability is only a function of its own saturation. Similar results were reported by Leverett and Lewis, Corey et al., Saraf and Fatt[11], Schneider and Owens[12] and Saraf and Batycky. There is no evidence of data scatter in the brine/oil/gas relative permeability data.

COMPARISON OF EXPERIMENTAL OIL RELATIVE PERMEABILITIES WITH PREDICTED OIL RELATIVE PERMEABILITIES FROM AVAILABLE MODELS

Flow of Newtonian fluids through porous media is described by Navier-Stokes (N-S) equations, the continuity equation and appropriate initial and boundary conditions. In general, these equations are coupled, nonlinear partial differential equations and difficult to solve. To find a solution, different investigators have idealized the porous media in some way to enable simplification of the Navier-Stokes equations.

One approach has been to picture the porous medium as a bundle of uniform capillary tubes parallel to the direction of flow. Based on this assumption, the N-S equation in one dimension for steady incompressible flow is reduced to the Hagen-Poiseuille law applicable to a single capillary tube. This law combines with Purcell's[13] concept on capillary pressure to yield the total flow equation over the entire range of capillaries. Several other capillary models have been proposed in addition to the parallel type of model. Statistical theory has also been used to describe flow of fluid through porous media. Most of these models primarily consider single-phase flow and cannot be extended to multiphase flow due to inherent limitations of assumed analogies. The only attempt to describe multiphase flow in porous media is Purcell's parallel type capillaric model. Based on the assumption of porous media being represented as a bundle of capillaries, many models have been developed since 1950.

Corey's,[7] Land's,[14] Naar-Wygal's,[15] and Naar-Henderson's[16] models are compared in this study. Corey's model predicts relative permeability during drainage processes whereas Naar-Wygal's and Naar-Henderson's models were developed for imbibition processes. Land's equation can be applied to either drainage or imbibition processes. These models are based on Purcell's parallel type capillaric model but differ from each other on the several assumptions made in the models. Relative permeabilities in three-phase flow obtained from this model were compared with experimental data obtained at NIPER (see previous section). Water and gas relative permeabilities were not compared.

The data necessary for use of these models are presented in table 1. Tables 2 and 3 show the experimental oil relative permeability data and the values predicted from the models. Analysis of the results shows that none of the models predicts experimental data adequately. As shown in table 4, Land's (imbibition) and Naar and Henderson models predict oil relative permeability within 4 percent of the experimental values. Those two models gave the best prediction from all models tested. Corey's and Land's (drainage) models predict within 7 to 14 percent of the experimental values.

All of the models compared predict similar imbibition and drainage oil relative permeabilities, which may indicate that Purcell's parallel type capillaric model may not be adequate for this type of flow.

An attempt was made to compare experimental oil relative permeability with values predicted from Stone's I and II models,[17-18] Dietrich and Bondor's modification of Stone's second model,[19] and Nolen's modification of the second Stone model.[20] These models are called probabilistic models. To apply these models, water-oil and oil-gas relative permeability data are required. Due to the unavailability of two-phase data in the core for which three-phase data were available, Honarpour's et al.[21] empirical equations for estimating two-phase relative permeability in consolidated rock were used. It was found that for all oil saturations available in the three-phase relative permeability experimental data, negative oil relative permeability was predicted from these models. The fact that oil saturation in the experimental data is lower than residual oil saturation in the presence of water may explain this behavior. These results are partly supported by Fayer's and Matthew's[22] findings. In their work, they reported that oil relative permeability predicted by Stone's Method I and II when oil saturation approaches residual oil saturation does not agree with experimental oil relative permeability.

The last work to be performed during this study was the estimation of the parameters P_1 through P_7 for each phase using the three-phase relative permeability model (TPKR) developed at NIPER[2] and experimental data obtained in this work (see previous section). Using previously published experimental data[3,11,23-25] the TPKR model estimated relative permeabilities of each of the three phases with an error of only 0.52 percent. A detailed discussion of these results is available in reference 2. An average error of less than 0.16 percent was obtained when the TPKR model was used to estimate the parameters for each phase using the experimental data measured during this investigation. This once again shows that three-phase relative permeability behavior can be represented by a mathematical model like TPKR.

RESULTS

- Experimental equipment for the measurement of three-phase relative permeability at high pressures using x-ray absorption and microwave attenuation techniques has been set up.

- More than 50 three-phase relative permeability points have been measured at low pressure. The preliminary analysis of the results shows (1) that the brine permeability is only a function of its own saturation, and (2) that the shape of oil (gas) isoperms are concave toward the 100 percent oil (gas) apex, indicating that they are functions of all three saturations.

- Purcell's parallel type capillaric model tested did not predict oil relative permeability in a three-phase system adequately.

- Probabilistic models at oil saturation (in a three-phase system) lower than residual oil saturation (in a two-phase system) did not predict oil relative permeability adequately.

- An average amount of less than 0.16 percent was obtained when the TPKR model was used to fit the three-phase relative permeability experimental data obtained in this study.

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TABLE 1. - Data required in capillaric models

S_{wc}	=	connate water saturation = 22.1 percent
S_{orw}	=	residual oil saturation in the presence of water = 42.0 percent
S_{org}	=	residual oil in the presence of gas = 5.0 percent
S_{ob}	=	$\frac{(S_w - S_{wc})^2}{2(1-S_{wc})}$

TABLE 2. - Experimental and predicted imbibition oil relative permeability data

Fluid saturation			k_{ro}			
S_w	S_o	S_g	Exp.	Naar-Wygal	Naar-Henderson	Land
0.4226	0.3079	0.2695	0.1575	0.0586	0.0567	0.0643
0.4671	0.3509	0.1820	0.1516	0.0962	0.0989	0.1106
0.5122	0.2705	0.2173	0.1203	0.0343	0.0458	0.0512
0.5623	0.2502	0.1875	0.0713	0.0209	0.0397	0.0439
0.5880	0.2501	0.1619	0.0312	0.0181	0.0418	0.0461
0.6070	0.2573	0.1357	0.0362	0.0184	0.0476	0.0522
0.6126	0.1867	0.2007	0.0678	0.0029	0.0171	0.0189
0.6229	0.2521	0.1250	0.0393	0.0148	0.0459	0.0692

TABLE 3. - Experimental and predicted drainage oil relative permeability

Fluid saturation			k_{ro}		
S_w	S_o	S_g	Exp.	Corey	Land
0.2255	0.2905	0.4840	0.1545	0.0173	0.0266
0.2538	0.2381	0.5081	0.1666	0.0097	0.0148
0.4880	0.2847	0.2273	0.1338	0.0587	0.0576
0.5439	0.3462	0.1079	0.1069	0.1316	0.1235
0.5772	0.2524	0.1704	0.0578	0.0492	0.0465
0.5985	0.2825	0.1190	0.0310	0.0748	0.0696
0.2974	0.5088	0.1938	0.0686	0.2621	0.2723
0.5510	0.2696	0.1794	0.0595	0.0576	0.0548
0.5906	0.3186	0.0908	0.0425	0.1097	0.1017
0.6059	0.2974	0.0967	0.0301	0.0901	0.0834

TABLE 4. - Average and standard deviation of the difference between experimental and predicted oil relative permeability

	Average deviation, [1] ($\overline{\Delta k_{ro}}$)	Standard deviation of the average deviation, [2] ($S(\overline{\Delta k_{ro}})$)
Corey (drainage)	7.7	6.5
Land		
Drainage	7.4	6.8
Imbibition	4.3	2.7
Naar-Wygal (imbibition)	5.1	5.0
Naar-Henderson (imbibition)	4.2	3.4

[1] $$\overline{\Delta k_{ro}} = \frac{\sum ABS[k_{ro}(exp) - k_{ro}\ (model)]}{N}$$

[2] $$S(\Delta k_{ro}) = \frac{\sum(\Delta k_{ro} - \overline{\Delta k_{ro}})^2}{N-1}$$

N = number of data points.