A Comparison of Propane and Carbon Dioxide Solvent Flooding Processes

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A laboratory investigation was conducted on oil displacement from porous media by the use of either a slug of propane followed by gas or a slug of carbon dioxide followed by water. A comparison was made of the efficiencies of these two solvent flooding processes for petroleum reservoirs. The results of flooding experiments on cores and on scaled pattern models showed the effect, on oil recovery, of type of porous medium, pore geometry, length to width ratio of the flood pattern, fluid viscosities, and miscibility. Oil recoveries of from 60 to 80% of the original oil in place were obtained by these solvent flooding processes as compared with conventional waterflood recoveries of between 35 to 50% on the same cores and linear models. Furthermore these recoveries were obtained with solvent slug sizes of 10 to 30% of a hydrocarbon pore volume, with less solvent being required as the length of the flood path increased. Data showing the relations between mobility ratio and volumetric sweep efficiency for the propane-gas and carbon dioxide water flooding processes for two widely different types of porous medium are included in this paper.

It was concluded that in reservoirs where pressure, oil viscosity and composition, and flooding pattern are favorable, either of these solvent flooding processes would give oil recoveries considerably higher than conventional waterflood or gas drive. It was further concluded that this improved recovery would be realized earlier in the life of a flood with carbon dioxide-carbonated water than with propane followed by gas.

Miscible-phase solvent flooding processes, which are designed to increase oil recovery from petroleum reservoirs, involve the injection of a small quantity of a petroleum solvent into the reservoir, followed by an inexpensive scavenging fluid which is miscible with the solvent. Essentially complete displacement of oil from the pores of reservoir rock has been obtained by this technique. Flooding with propane followed by natural gas is a typical solvent flooding process. This process has been investigated extensively in the laboratory and to some extent in the field. The results of investigations reported in the literature have shown that although high oil recovery is possible by this technique, a number of factors determine whether high-oil-recovery efficiency actually will be attained in the field.

Carbon dioxide is not completely miscible with most reservoir oils at common reservoir pressures, but it is highly soluble in these oils at pressures above 700 lb./sq. in. There is appreciable swelling and reduction in the viscosity of oil when carbon dioxide is dissolved in it. Carbon dioxide is also highly soluble in water at elevated pressures, so water is a satisfactory material to drive a slug of carbon dioxide through an oil-bearing reservoir.

A number of investigations of the use of carbon dioxide to improve oil recovery have been reported in the literature (*1*, *2*, *3*, *4*, *5*). These studies were conducted on uniform porosity sandstone at relatively low temperatures and pressures. The principal results of a recent investigation (*6*) showed that solvent flooding with relatively small quantities of carbon dioxide followed by carbonated water at pressures above 900 lb./sq. in. gauge resulted in oil recoveries that were from 50 to 150% greater than those obtained by conventional water flooding or solution gas drive. These improved recoveries were realized at temperatures above 100°F. on uniform porosity sandstone and irregular porosity carbonate rock.

The purpose of the work presented in this paper was to compare the relative merits of carbon dioxide-water and propane-gas solvent flooding processes. In order to make this comparison it was necessary to evaluate the effects of a number of factors on the efficiency of each of these processes. The factors included in the study were uniformity of the porous medium, miscibility between oil and solvent, viscous fingering and permeability variations, gravity segregation, and areal sweep efficiency.

APPARATUS AND PROCEDURE

Experimental work was conducted on sandstone and dolomite cores and models at various pressures. Refined oils and crude oils were displaced by carbonated water-driven carbon dioxide slugs and by hydrocarbon gas-driven propane slugs.

Consolidated cores having the following properties were used:

	Permeability, (md.)	Porosity, %
Berea sandstone	150-200	19-21
McCook dolomite	50-140	16-20

The cores were 3½ in. in diameter and 0.7, 1, and 7.5 ft. in length; the long ones consisted of three or four short cores mounted end to end in capillary contact. The cores were encased in neoprene tubing within steel core holders. Flow of fluids were confined to the pore space of the core by external pressure on the neoprene sleeve in excess of the internal pressure used in the core. Fluid-distribution plates were used to minimize end effects.

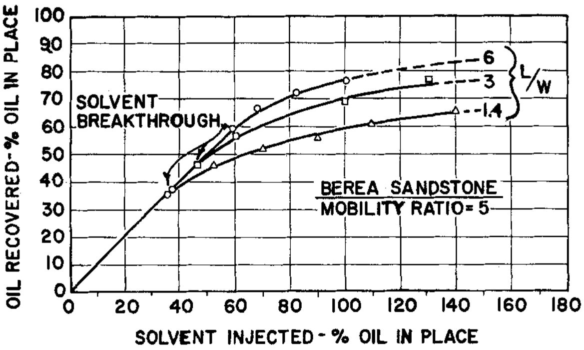

Fig. 1. Effect of model length to width ratio on oil recovered.

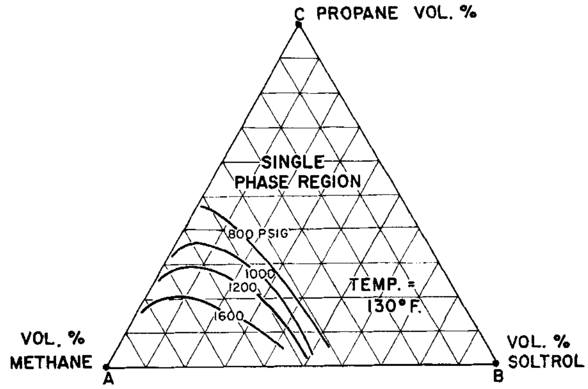

Fig. 3. Miscibility study of methane-propane-soltrol system.

The sandstone is a relatively uniform porosity material. The dolomite is an irregular porosity carbonate rock containing vugs and high permeability channels. The rock is a micro to medium crystalline dolomite. The porosity consists of interstitial pores, 5 to 10 microns in size, and irregular vugs, 50 to 2,000 microns in size.

The models used in this study were slabs of the above core materials dimensionally scaled to various ratios of length to width and length to depth of flood pattern. Holes were drilled in the ends of some of the models to provide injection and production wells in a simulated line drive reservoir flooding pattern; both radial and linear flow existed in the flooding of these models. In other cases the entire end faces of the models were opened to injection and production, giving only linear flow. The sizes of the models were ½ in. thick by 12 in. long and 2, 4, and 12 in. wide. One Berea sandstone model 1 in. x 6 in. x 18 in. long was also used.

Fluids

Fluids used in the cores were soltrol, propane, methane, carbon dioxide, and a west Texas crude oil having the following properties:

Density at 70°F., —0.837 g/cc.
Viscosity at 70°F., —5.1 centipoises
Viscosity at 125°F., —2.2 centipoises
Carbon residue-conradson, —1.2 wt. %

A 10% sodium chloride solution was used in saturating and flooding the sandstone cores. This salt solution was used to prevent swelling of clays present in these cores. Distilled water was used in the dolomite cores where clay swelling was not a problem. Carbonated brine was used on the sandstone and carbonated distilled water on the dolomite. The brine or water was carbonated prior to the displacement experiments to a point approaching saturation at flooding temperature and pressure.

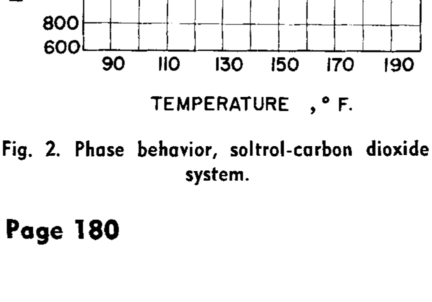

Fig. 2. Phase behavior, soltrol-carbon dioxide system.

The fluids used in the models were refined oils of various viscosities and densities. For the most part miscible fluids were used; however some experiments using water and/or alcohol and oil were performed. In some cases iodobenzene, ethyl iodide, or potassium iodide was added to either the displacing or displaced fluids so that the progress of the flood could be followed by x-ray pictures during the displacement experiments. These pictures clearly showed the shape of the displacement front.

EXPERIMENTAL DETAILS

The experimental work on cores was designed to evaluate the recovery efficiency of carbon dioxide-carbonated water and propane-natural gas floods on consolidated linear systems containing reservior fluids at typical reservoir temperatures and pressures. In preparation for the displacement experiments the cores were first saturated with water and then flooded with oil at the pressure and temperature desired. A series of displacement tests were made on the same core for comparative purposes. After each one the pressure in the core was dropped to atmospheric pressure, and the core was flushed with brine or distilled water. In preparation for the next experiment the pressure in the core was raised by brine or water injection, and the core was flooded again with several pore volumes of the desired oil to obtain the original oil-in-place. By this procedure any gas phase (carbon dioxide, propane, or methane) was removed from the core and the original oil-in-place saturation was obtained. New cores were used after a series of runs or after appreciable changes were noted in permeability of the cores. Material balances were made for each experiment, and occasional checks were made on oil-recovery data by extracting the cores and determining the amount of residual oil by distillation.

The displacing fluids, carbon dioxide, propane, methane, and water, were injected in measured quantities from calibrated containers. The carbon dioxide slugs and carbonated water injected were measured at 75°F., and 1,000 lb./sq. in. gauge regardless of flooding conditions. In general about three-fourths of the total carbon dioxide used was contained in the slug and one-fourth in the water. Flood front advance rates of about 15 to 25 ft./day were used in the short core tests; rates of 5 to 10 ft./day were used in the long core tests. Displacement rates were controlled by a backpressure regulator through which produced fluids were discharged. The carbonated water injection was continued until produced water-oil ratios reached 100 to 1; at this point the pressure depletion of the core was performed. The propane-methane floods were continued until gas-oil ratios of 20,000 to 1 were attained. During the displacement tests the core effluent was collected in a gauge where it could be observed and measured. In some of the experiments samples of the effluent were taken as the flood progressed, and their compositions were determined. The volume of gases leaving the recovery vessel was measured under atmospheric conditions by means of a wet test meter.

Model Studies

The experimental work on the models was designed to study the effects of mobility ratio, ratios of length to width and length to depth of flood pattern, displacement rate, gravity segregation, and permeability variations. The models were completely saturated with oil of the desired viscosity and density; displacement fluid of the desired viscosity and density was injected into the model at a constant rate to simulate a flood front

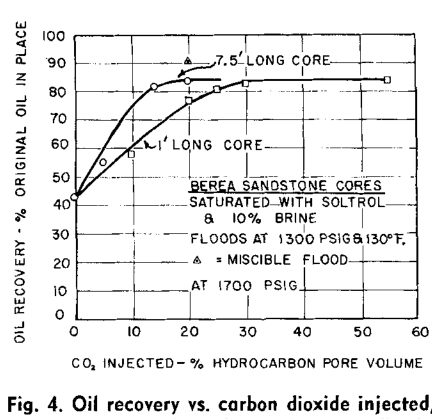

Fig. 4. Oil recovery vs. carbon dioxide injected, for carbon dioxide-carbonated water floods.

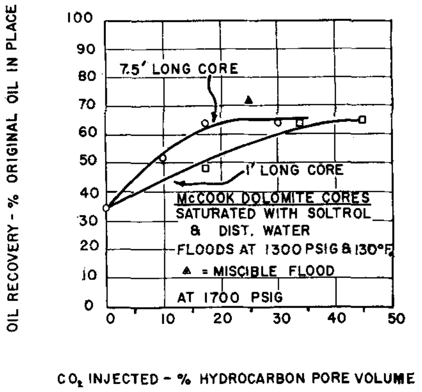

Fig. 5. Oil recovery vs. carbon dioxide injected, for carbon dioxide-carbonated water floods.

advance of about 2 ft./day. The total effluent was measured at intervals, and samples were analyzed by refractive index measurements to determine the proportions of displacing and displaced fluids. Some studies were made in which the oil-saturated model was flooded with water (immiscible displacement). The progress of the miscible and immiscible floods was observed with the aid of X-ray pictures.

The model experiments were scaled to represent the prototype with respect to the following:

1. Flood pattern (L/W and L/D) model = (L/W and L/D) reservoir. A uniform thickness throughout the flooding path was assumed.
2. The ratio of viscosities of displaced and displacing fluids (μ_o/μ_s) model = (μ_o/μ_s) reservoir
3. The ratio of gravitational and viscous forces $q\,\mu_s/L^2\,k\,\Delta d$ model = $q\,\mu_s/L^2\,k\,\Delta d$ reservoir
4. Pore geometry. Two widely different rock and porosity types were used, each of which is typical of reservoir rock.

The dispersion of miscible fluids which takes place during a solvent flood in a reservoir is another condition which should be properly scaled. However the complexity of the dispersion mechanism in the reservoir precludes exact laboratory scaling of this factor. An investigation by Taylor and Aris (*7, 8*) has described the amount of mixing between miscible fluids of equal viscosity and density in single, straight capillaries. Their theory leads one to predict first that the displacement of oil from an invaded pore will be complete and second that the mixing zone will decrease in size as the length of flooding path increases. However in the practical consideration of solvent flooding in porous media the unequal viscosities and densities of the fluids involved and the irregular flow channels cause the size of the mixing zone to vary considerably from these predictions. More mixing between oil and solvent occurs under reservoir conditions due to mechanical mixing in the intricate pore system. Consequently the dispersion is a function of the pore geometry of the porous medium. However fingering, channeling and/or over-riding of the low viscosity, low density solvent also occurs in such a system. Bypassing of regions of oil in large porous bodies results under these conditions.

Solvent floods on long, narrow, uniform porosity cores or models give results which indicate stabilized oil-solvent mixing zones and piston type of displacement, even at unfavorable fluid viscosity and density ratios. Large diameter cores or wide models scaled to realistic reservoir dimensions do not produce a stablized zone even in a homogeneous porous medium. Fingering and channeling of solvent take place owing to unfavorable solvent-oil viscosity and density ratios and to permeability variations within the porous medium. The results of solvent floods in dimensionally scaled, pattern models shown in Figure 1 illustrate this point. The oil recovery obtained in the long narrow model (length/width = 6) is considerably higher than that shown for the models with lower length/width ratios. X-ray shadowgraphs taken during the floods also showed that very little fingering of solvent took place in this narrow model and that a high percentage of the model was contacted during the flood. Furthermore the results obtained with the narrow model were rate sensitive, above 2 ft./day, whereas those in the wider models were not (*10*).

The data obtained with large diameter cores and models with low length to width ratios probably would be more representative of field applications of solvent flooding. Although the dispersion of the fluids in the reservoir was not completely represented in either the cores or models used, the differences are principally those associated with mixing zone size. Such differences would affect slug-size estimation but would not significantly affect oil recoveries. No attempt was made to determine the optimum slug size which would be required in the reservoirs represented by this experimental work. The oil recovery shown for the solvent flooding processes assume a sufficient solvent slug to effect these recoveries.

EXPERIMENTAL RESULTS AND DISCUSSION

Crude Oil Systems

Oil recoveries were determined for both carbon dioxide and propane flooding processes in short and long, 3½-in. diameter sandstone and dolomite cores. The cores contained a west Texas crude oil and water prior to the floods. All floods were conducted at 1,300 lb./sq. in. gauge and 125°F. The results on both the sandstone and dolomite cores were similar for each process and indicate marked improvement over conventional water and gas flooding. Less solvent was required for equivalent oil recoveries in the longer cores, particularly in the case of the irregular dolomite cores. Oil recoveries from the dolomite cores were generally lower than recoveries from sandstone cores. Complete recovery of

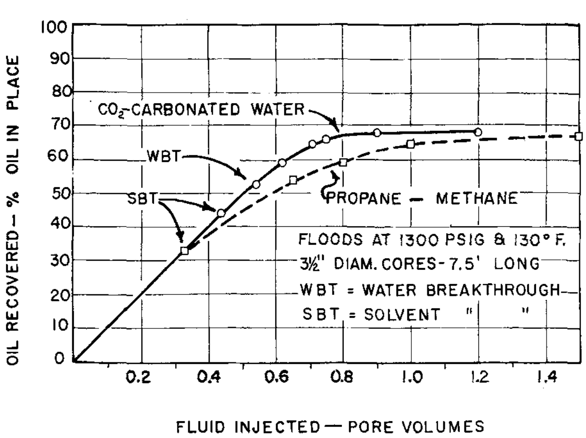

Fig. 6. Solvent floods in long dolomite cores.

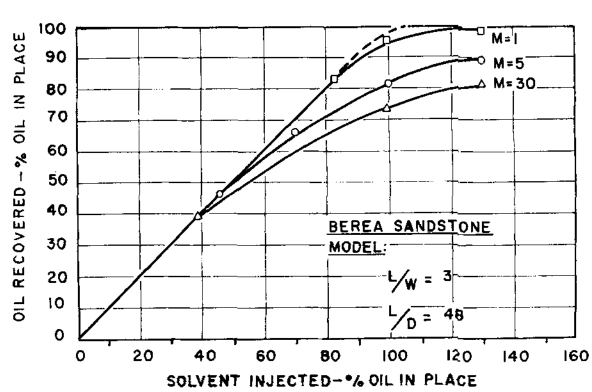

Fig. 7. Effect of mobility ratio on oil recovered, linear model floods.

oil was obtained by injecting large quantities of propane; even with the injection of large amounts of carbon dioxide recovery was not complete. For example three pore volumes of propane were injected to recover 92% of the oil in place in the long sandstone core, whereas three pore volumes of carbon dioxide produced very little more oil than one pore volume (65%).

Refined Oil Systems

Similar studies were made with refined oils rather than crude oil in place. These studies were designated to investigate further some of the factors affecting the oil-recovery efficiency of these processes. Results of equilibrium phase behavior studies of the carbon dioxide-refined oil system and the propane-methane-oil system are presented on Figures 2 and 3. These phase diagrams were used in conjunction with data on the composition of the core effluent to determine miscibility relationship during the solvent floods.

The results of the flooding experiments are shown on Figures 4 through 6. These experiments were conducted under the same conditions as those made with the crude oil. Oil recoveries shown on Figures 4 and 5 for zero carbon dioxide injection represent conventional waterflood recoveries. The results were similar to those obtained with crude oil, except that the refined oil recoveries on the sandstone were higher than the crude-oil recoveries. These improved recoveries probably are due to the improved mobility ratio in the flooding of the refined oil, as compared with that which exists in flooding the crude oil. (The viscosity of the soltrol is 0.8 cp. under flood conditions compared with a viscosity of 2.2 centipoises for the crude oil). With the dolomite core the recovery of refined oil was the same as the recovery of crude oil. It is believed that the effect of the severe permeability variations in the dolomite overshadowed any small improvement in mobility ratio.

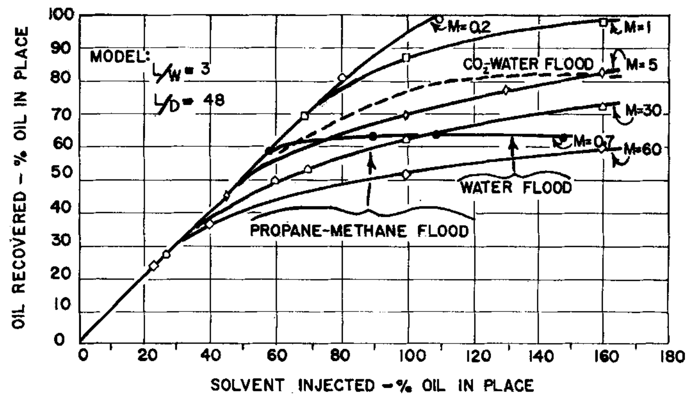

Fig. 9. Effect of mobility ratio on oil recovered, radial model floods on Berea sandstone.

Figure 6 presents a comparison of linear solvent slug floods on the dolomite core. Solvent slugs of 20% of the hydrocarbon pore volume were used in these experiments.

Again less solvent was required in the longer cores for both the propane and carbon dioxide floods. In order to provide additional information on the effect of flooding path length on carbon dioxide solvent requirements a series of carbon dioxide-carbonated waterfloods were conducted on a 30 ft., 2½-in. diameter sand packed model containing soltrol and water. The floods, conducted at 1,300 lb./sq. in. gauge and 130°F., were similar to those on the 1 and 7.5 ft. consolidated cores. A summary of the oil recovery results obtained is given below:

Carbon dioxide injected, % hydrocarbon pore volume	Oil recovered, % oil in place
9	83
14	88
20	89

These results can be compared with those obtained on the consolidated sandstone shown on Figure 4. The sand pack was more uniform than the sandstone, and the length to width ratio was considerably more favorable. These conditions favor low solvent requirement. However the actual solvent requirement for this longer core was only slightly less, than the requirement for the 7.5-ft. consolidated sandstone core. A certain minimum carbon dioxide slug size is probably necessary for maximum recovery regardless of length of flooding path. This can be explained by the fact that carbon dioxide and oil and carbon dioxide and water are not completely miscible at the pressure and temperature of these floods.

FACTORS AFFECTING OIL RECOVERY

The results of the core studies indicated that the following factors affect the efficiency of these solvent flooding processes:

1. Miscibility between oil, solvent, and driving fluid.
2. Viscosity (mobility) ratio of oil and solvent.
3. Permeability variations within the core.
4. Density difference between oil and solvent.
5. Areal sweep efficiency in pattern flooding where both linear and radial flow exist.

Miscibility

Inspection of the phase diagram of the carbon dioxide-soltrol system (Figure 2) and the flooding results (Figure 4 and 5) shows that oil recovery is affected by variations in miscibility of oil and carbon dioxide. The recovery of this oil under miscible conditions (1,700 lb./sq. in.) was higher than that obtained when miscible conditions did not exist. As carbon dioxide is not completely miscible with most reservoir oils, except at extreme pressures, complete displacement in the individual pores of the rock is not to be expected in carbon dioxide flooding. Propane on the other hand is completely miscible with most crude oils and will effect complete pore displacement so that essentially 100% oil recovery is possible.

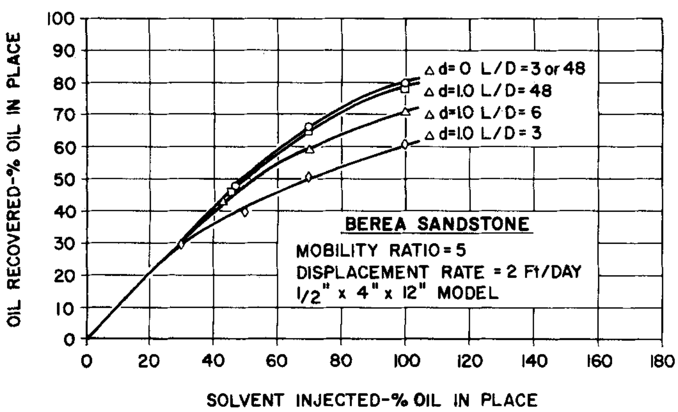

Fig. 8. Effect of gravity segregation on oil recovered, linear model floods.

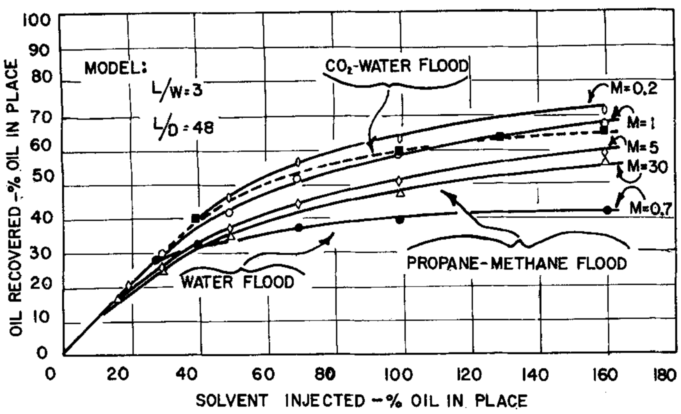

Fig. 10. Effect of mobility ratio on oil recovered, radial model floods on McCook dolomite.

Fingering

Examination of the displacement mechanism in uniform porous media shows that even though complete miscibility exists, piston type of displacement resulting in 100% oil recovery may not occur because of viscous fingering. This fingering, due to the unfavorable viscosity ratio between displacing and displacing fluids, results in bypassing of oil. Figure 7 shows this effect in the linear sandstone model. The viscosity ratio (M) shown is the ratio of the viscosity of the displaced oil to the viscosity of the displacing solvent; this is less favorable as M becomes larger. For less favorable mobility ratios more solvent is required for a given recovery.

Henderson (9), Blackwell (*10*), and others have shown that linear miscible floods, on uniform porosity sand, at a favorable mobility ratio ($M=1$) give 95% oil recovery at solvent breakthrough and 100% oil recovery at about 1.1 pore volumes throughput (dotted curve—Figure 7). Oil recovery for this mobility ratio on the sandstone used in this study was 83% at breakthrough, while 1.5 pore volumes throughput were required for 100% oil recovery (Figure 7). As no fingering due to unfavorable mobility ratio takes place under these conditions, the lower oil recoveries obtained can be attributed to variations in the pore geometry of the sandstone. For comparative purposes these results are assumed to represent maximum pore-displacement recovery for this porous medium.

Carbon dioxide-water and propane-methane floods on linear systems show similar crude oil recoveries. It appears that the higher pore displacement efficiency of the propane-methane flood is balanced by the more favorable dispersion of carbon dioxide into the oil and by the more favorable mobility ratio of carbon dioxide-carbonated water floods. The difference between the pore displacement efficiency of carbon dioxide and that of propane is believed to be due to the fact that carbon dioxide behaves as a miscible gas as it disperses into the oil, while propane behaves as a miscible liquid. Initially the dispersion of carbon dioxide is controlled by the equilibrium phase behavior of gas and liquid. As the vapor-liquid equilibrium constant for carbon dioxide is large, the dispersion is high in all directions. Fingering is minimized by the high rate of dispersion between any fingers which form; also as part of the oil is vaporized at the carbon dioxide-oil front a hydrocarbon-carbon dioxide bank or zone is formed which further minimizes fingering.

The water following the carbon dioxide is also partially miscible with carbon dioxide. Here again the equilibrium constant controls dispersion and being high tends to keep the water-solvent front sharp. Also the mobility ratio for water displacing carbon dioxide is very favorable. Some carbon dioxide is left in bypassed oil and in water, thereby increasing the amount required; however this carbon dioxide assists in the blow-down recovery (*6*).

Permeability Variations

Permeability variations have a marked effect on the displacement efficiency of solvent floods. Even small variations probably initiate the fingering described above. When the variations become severe, they control the displacement to a large extent. This is shown by the results obtained in the flooding of the irregular porosity dolomite when channeling of the injected fluids occurred even at favorable mobility ratios. The results shown on Figure 10, compared with those on Figure 9 for the more uniform sandstone, show the effects of mobility ratio on oil recovery in the irregular dolomite. The oil recovery efficiencies at a favorable mobility ratio ($M<1$) are low, and those at the more unfavorable mobility ratios are not reduced as much as in the case of the more uniform sandstone. It appears that the effects of fingering and permeability stratification are not strictly additive. On the other hand complete recovery of oil from the irregular porosity rock was not attainable with a practical amount of miscible fluid.

Gravity Segregation

The effect of density difference between solvent and oil was found to be dependent largely upon the ratio of length to depth of a model or core. In laboratory linear floods on cores, gravity segregation between solvent and oil is not significant because of the high displacement rates usually used. Experiments at lower flooding rates show the segregation effect to be important where vertical permeability exists in the core. However as shown in Figure 8 results of displacement experiments on dimensionally scaled sandstone models indicate that any detrimental effect of gravity segrega-

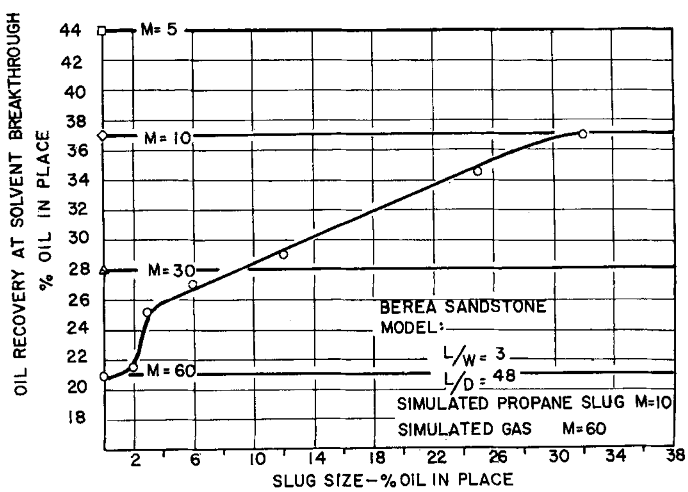

Fig. 11. Effect of slug size on volumetric sweep efficiency, for simulated propane slug followed by gas floods in scaled models.

tion would be minor for reservoirs having high length to depth ratios, thicknesses less than 40 ft., and permeabilities less than 150 millidarcies. In porous media containing highly permeable channels or stratified zones channeling of solvent would be much more serious than gravity segregation.

Sweep Efficiency

A quantitative measure of the volumetric efficiency of carbon dioxide-carbonated water and propane-methane floods is shown on Figures 9 and 10 for the uniform sandstone and irregular porosity dolomite, respectively. The effective over-all mobility ratio for these floods was determined by comparing oil recoveries obtained in the long core experiments with those obtained at various mobility ratios on the linear models. These were checked by simulated solvent-gas floods on scaled pattern models (Figure 11). A mobility ratio of about 30 was found to be applicable for the propane-methane floods, with the use of a 10% propane slug assumed. The mobility ratio for carbon dioxide-carbonated water floods was assumed to be the same as that in a waterflood. Simulated carbon dioxide-carbonated water flood on the radial flow models showed that the areal sweep efficiency was at least as high as that of a waterflood.

The models used in the above study were designed to give both radial and linear flow in a simulated line-drive pattern. As the models were slabs of the sandstone and dolomite, the effects of bypassing oil within the swept pattern are included in oil recoveries shown. X-ray shadowgraphs and Figures 7 and 9 show the relation between the area swept in a linear flow model and a radial-linear pattern flow model. The differences between oil recoveries obtained by flooding these models is a measure of the areal sweep efficiency.

Evaluating the Carbon Dioxide and Propane Flooding Processess. In estimating the expected field performance of flooding processes from laboratory data the following must be known: first the degree to which the formation will be contacted by the injected fluids, second the degree to which the reservoir oil is displaced from the zone contacted by the injected fluids, and third the degree to which the reservoir rock is simulated by the laboratory models. In the present study core-displacement tests have been used to provide data on the degree to which individual pores are flushed by the injected fluid (this is believed to be a valid premise because of the piston-like movement of the injected fluids that should occur in these linear systems). The data obtained from pattern flood models have been used as a measure of the volumetric sweep efficiency which can be expected in the field.

The one remaining factor which must be considered (simulation of the reservoir) is influenced by properties of the reservoir rock and must be estimated for each field. To aid in accounting for this factor in the comparison of solvent flooding processes two widely different rock types were used in the current study. Based on the information from core-displacement experiments and model studies on uniform sandstone and irregular dolomite the following table presents a comparison of field recoveries for the flooding systems and rock types studied:

COMPARATIVE OIL RECOVERIES, % OIL IN PLACE

	Propane-Methane flood	Carbon dioxide carbonated waterflood	Conventional waterflood
On Berea sandstone			
at breakthrough	33	52	58
at 1 pore volume total fluid injected	63	76	62
at 1.6 pore volume total fluid injected	72	81	63
On McCook dolomite			
at breakthrough	18	39	26
at 1 pore volume total fluid injected	48	59	40
at 1.6 pore volume total fluid injected	56	65	41

SUMMARY AND CONCLUSIONS

1. Total oil recoveries obtained from both dolomite and sandstone cores by the solvent flooding processes studied were substantially higher than those obtained by water flooding or gas injection. Regardless of the flooding process used less oil was recovered from the irregular dolomite cores than was produced from the uniform sandstone cores.

2. The additional oil recovered (over that obtained from a conventional waterflood) from the irregular porosity rock by both solvent flooding processes was achieved early in the life of the floods compared to that obtained on the uniform sandstone.

3. Less total fluid injection was required for the carbon dioxide-carbonated water process to obtain this increased oil recovery than was needed for the propane-methane process. High oil recovery early in the life of a flood is indicated for field application of carbon dioxide-carbonated water flooding. Carbon dioxide required would be greater than the amount of propane needed for a given field application.

4. The high oil recoveries obtained by carbon dioxide-carbonated water flooding (relative to the recoveries obtained by propane gas) are believed to be due primarily to the more favorable mobility ratio of the carbon dioxide-carbonated waterflood.

NOTATION

D = thickness, cm.
k = permeability, millidarcy
L = length, cm.
M = mobility ratio, viscosity displaced phase/viscosity displacing phase
q = volumetric flow rate, cc./sec.
W = width, cm.
Δd = density difference, oil and solvent, g./cc.
μ = viscosity, centipoises

Subscripts

o = displaced fluid, oil
s = displacing fluid, solvent

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