Paper - SCA # 9018 Imbibition Flooding with CO_2-Enriched Water

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Summary

The objectives of the laboratory research were to evaluate the improvement in the imbibition rate and recovery efficiency at room temperature and atmospheric conditions in core samples by using CO_2-enriched water in place of regular formation brine. Tests were run using 1 in. diameter cores in visual imbibition cells.

The results of laboratory experiments show the inclusion of CO_2 into the imbibed water improves both the imbibition rate and the recovery efficiency. A 1% carbonated water solution recovered an additional 8% of oil in place in a 76 md sandstone, and an additional 16% of oil in place from a 7 md limestone during a standard soak time of 72 hours.

The study of the new displacement method with the 1in. cores indicated a substantial portion of mobile oil remains attached to the rock face as oil droplets because of capillary retention during brine imbibition. The inclusion of CO_2 in the flood water greatly reduced both the effect of capillary retention and the contact angle. The release of the oil held by capillary retention along the walls of a fracture system in a reservoir stimulated both oil recovery and imbibition rate.

The major factors affecting the increased recovery appear to be the increase in oil mobility, the introduction of a gas phase that acts as solution-gas drive when a drawdown is induced, and the reduction of interfacial tension. Another significant factor is the matrix dissolution of carbonate rocks and clay mineral clean up.

Introduction

Large volumes of oil remain trapped in fractured, dual porosity, low matrix permeability reservoirs after ordinary primary and secondary recovery methods have ceased to be economically viable. Oil production from these reservoirs tends to come from the fractures and "near" fracture matrix blocks. The fracture system prevents the economic installation of conventional secondary recovery methods because the injected fluids tend to channel through the fractures and bypass the oil-filled matrix rock.

However, capillary effects cause a portion of the injected water to be imbibed into the rock matix. Oil production is achieved as the water imbibes into the rock matrix and displaces oil out into the fracture system where the displaced oil is carried away to a producing well. This process is very slow. In certain instances this time-dependent, water soaking technique has increased oil recovery from both Austin Chalk and Sprayberry wells(Brownscombe et.al., 1952). The technique has lately gained widespread acceptence in the Austin Chalk producing trend because of the moderate increases in recovery rate caused by a huff "n" puff treatment of individual wells.

A substantial amount of oil could possibly be produced from these reservoirs if the rate or recovery efficiency of the water-imbibition, oil-displacement method could be improved. The proposed solution to the problem of increasing the rate and recovery efficiency of this technique is to replace the normal brine with carbonated water. The inclusion of CO_2 in the imbibed water permits a number of therapeutic effects which aid in enhancing oil recovery and recovery rate. These beneficiating effects are discussed below:

Crude Oil Volume Expansion - Dissolving CO_2 into crude oil causes the oil volume to increase. (Johnson et al., 1952) found up to a 35% increase in Bradford crude oil volume when CO_2 was transferred from the carbonated water to the oil phase.

Reduction of Oil Viscosity - The viscosity of the oil phase is decreased as CO_2 is absorbed(Johnson et al., 1952; Graham et.al., 1957). Bradford crude was observed to have a 50% reduction in oil viscosity when carbonated at 800 psig. Any reduction in oil viscosity can profoundly affect recovery efficiency in very low permeability matrix rock where oil transmissibility is of major importance. Scheidegger, 1957) stated that the water imbibition rate is inversely proportional to oil viscosity and is a function of the contact angle. A reduction of oil viscosity should therefore increase the imbibition rate.

Reduction in Interfacial Tension - A reduction in the interfacial tension between water and oil improves displacement in the reservoir (Dodds et.al., 1962). Another benefit is the reduction of capillary retention of oil on the rock face.

The Acidic Nature of Carbonated Water - Though a potential corrosion problem area, the acidic nature of carbonated water will clean up acid-soluble clay contamination in any core and widen pore throats in carbonate cores. (Bleakley, 1962) and (Crawford, 1963) have noted this well stimulation effect.

Induced Solution-Gas Pulsing - The effect of water and gas pulsing on increasing recovery from a low permeability reservoir has been studied by (Koch, 1958), Holm, 1976) and others. Gas pulsing was found to recover greater oil volumes than water pulsing. The creation of a solution gas drive by inducing a drawdown after carbonated water had imbibed into the core produced substantial increases in oil production from tight cores in laboratory experiments.

Objectives

The objectives of this laboratory experiment were twofold:

1. Compare the improvement in the imbibition rate and recovery efficiency in core samples using CO_2-enriched water rather than a regular formation brine.

2. Determine the dominant recovery mechanisms observed in the imbibition flood process and their relation with core rock properties.

Laboratory Apparatus and Procedure

Glass cells were used to make multiple runs of brine and carbonated water imbibition on 1-in. core samples at room temperature and atmospheric pressure. Figure 1 shows a sketch of typical glass core holder. The results were used to determine the effect of permeability and porosity of limestone or sandstone core samples on the imbibition process, and to measure the improvement in oil recovery using carbonated water over brine. The experiments were rapid and accurate, and showed a high degree of repeatability. A number of 1-in diameter core samples of varying lithology were tested using these chambered cells.

A constametric pump and Hassler sleeve assembly were used to saturate previously dried core samples with oil that had been previously saturated with brine in a vacuum saturation cell. The displaced oil was captured and measured a graduated cylinder as a function of time. The oil saturated core was then immersed in brine or carbonated water solution inside one of the visual cells. The amount of oil displacement (water imbibition) was measured in the volumetric tube at predetermined intervals during a standard 72-hour soak period. Volumetric readings were confirmed by mass material balance using Mettler digital balances. The carbonated water used for these tests was only 1% CO_2 by weight with a pH of 5. The core sample was then subjected to a brine imbibition test. All tests were conducted at 70^{o}F.

The sample was extracted and reset with a new oil and brine saturation for a subsequent imbibition test using carbonated water after completion of the first imibibiton flood. Any changes in saturation or permeability were noted. The same displacement procedure was then repeated using carbonated water.

The flood brine was distilled water mixed with 20,000 ppm NaCl. The 20,000 ppm salt concentration was felt to be sufficiently high to reduce clay interaction, but of sufficiently low salinity to allow adequate CO_2 solubility.

The oil was 35-degree API, diesel oil. Diesel oil was selected because CO_2 can cause asphaltene precipitation in some heavy crudes. Asphaltene precipitation would ruin the ability of the core to perform multiple runs.

Discussion of Results

Results from laboratory experiments indicate that the inclusion of CO_2 into the imbibed water improves both the imbibition rate and the recovery efficiency. Figures. 2 and 3 represent 72 hour imbibition runs on two consolidated, feldspathic sandstone, 1in. diameter core samples possessing different permeabilities.

Figure 2 shows the results of the imbibition runs performed on a 420-md core sample. The carbonated water run exhibits a oil expulsion rate and an extra 6% of oil in place when replacing imbibition test using formation brine.

The inclusion of carbonated water in the imbibed fluid in a 76-md. core increased recovery by a sligtly greater margin. Figure 3 shows an extra 8% of oil in place was recovered using CO_2 over brine. Measurements taken before and after the carbonated water imbibition tests indicated there was no appreciable change in the permeability for the sandstone cores. The curves representing recovery by carbonated water imbibition are seen to be approximately parallel to the brine imbibition curves in either of these two cases.

Table 1 lists the values of the recovery rates with time. Table 2 shows there was little change of the before and after permeability-to-oil measurements after a carbonated water treatment.

The effects of carbonated water imbibition on limestone cores was also studied. Figure 4 shows the increase in rate and recovery efficiency is readily apparent for a set of runs on a 29-md. limestone core. A vacuum pump was used to reduce the pressure in the cell to simulate dropping the reservoir pressure below the bubble point of CO_2. The dotted line represents oil production caused by the evolution of CO_2 gas when pressure was reduced in the cell. An extra 14% of oil in place was recovered using CO_2 in place of brine.

The acidic nature of the carbonated water dissolved 0.5% of the matrix by weight. Recovery was greater for the carbonate flood than for the ordinary brine flood. The slopes of the lines are not parallel, as was noted in the sandstone cores. The recovery curve is seen to be continuing to increase with time at a greater rate.

Studies performed on a 7-md carbonate core indicated no appreciable increase in recovery was observed until 24 hours soak time had elapsed. The dotted line in Fig. 5 represents oil production caused by evolution of CO_2 gas when the pressure was reduced in the cell. The carbonated water dissolved 0.4% of the matrix by the weight. An extra 16% of oil in place was recovered from this core sample using carbonated water over brine.

Table 3 presents the cumulative production data for the limestone core sample runs. Table 4 lists the oil in place percentage recovered by each imbibition run in limestone core, and the change in oil permeability as a result of carbonated waterflooding. In each case, oil permeability in the core sample increased after carbonated water had imbibed into the core. The increased recovery was apparently caused by matrix dissolution, i.e., increase in premeability and increased oil mobility. Improvement in recovery by the installation of a solution gas drive depletion mechanism in an otherwise dead oil was also noted.

The presence of secondary porosity improved the efficiency of the carbonated water flood. The vuggy limestone core imbibition tests seen in Fig. 6

show less than 10% oil-in-place recovery improvement with brine imbibition treatment. Recovery was increased to 23% of the OOIP when carbonated water was used. The brine flood appeared to relatively inefficient while the CO_2 flood performed exceptionally well. More work needs to be done in this area to determine if the presence of vugs truly affects the imbibition displacement process.

Factors Affecting Increased Recovery

The primary factors affecting the increased recovery appeared to be the increase in oil mobility and the introduction of a gas phase which acts as solution-gas drive in the otherwise dead oil when a drawdown was induced in the core.

The oil permeabilities in the tested core samples increased after contact with carbonated water an average 13-md in sandstone and 6-md in limestone cores. The increase of the pore throat permeability beneficially altered the mobility of the oil in place. Tables 2 and 4 compare the oil permeability changes in limestone and sandstone core samples.

The induced solution-gas drive was an extra energy source that displaced previously dead and immovable oil, increasing recovery efficiency in the core samples. Table 3 lists the oil production increase associated with the solution-gas drive. Induced gas drive tests were performed only on the limestone core samples. Similar results are expected for sandstone cores.

The largest increases in oil production appeared to occur in the limestone cores. The acidic nature of the carbonated water widened pore throats or removed damage in the carbonate rocks, which evidentally materially affected ultimate recovery.

Interfacial Tension and Capillary Retention - A large percentage of the displaced oil remained trapped on the rock face during brine flooding. Capillary retention was holding the displaced oil droplets onto the rock face. The contact angles observed at these points were greater than 90 degrees, indicating strongly oil wet conditions.

The inclusion of CO_2 in the flood water reduced both the amount of capillary retention and the contact angle at these points. These observations indicate the reduced interfacial tension and the acidic nature of the water is beneficially altering the rock wettability, making the core more water wet. Figure 7 is a sketch of the observations made during the experiments. The release of oil held by capillary retention along the walls of a fracture system in a reservoir would stimulate both oil recovery and imbibition rate.

Rock Properties vs. Imbibition Rate Equations - Graham and Richardson[3] attempted to mathematically model the imbibition rate in sandstone. They noted the exponential nature of the imbibition rate and concluded that the rate was proportional to the square root of permeability over porosity. Figure 8 represents the laboratory recovery data plotted against this relation. The laboratory experiments correlate well for sandstone, but not for limestone.

Applying the laboratory data to both correlations, linear proportions between rock properties and imbibition do seem to apply to sandstones, but the results contradict each other when comparing sandstones to limestones. The lithological differences between the sandstones and limestones tested are the chemical differences between the rock matrix and the pore size distribution. A large discontinuity in the limestone data curves is from the 30-md clay contaminated core, which may be a bad data point. One can conclude that if a uniform correlation does exist between imbibition rate and rock properties, it is dependent on pore size distribution and rock heterogeneity. More experimental data are required concerning the applicability of this correlation.

Note that for uncontaminated limestone cores, the percentage of oil in place recovered using carbonated water over brine is a constant 15% to 18% higher than that using brine regardless of the porosity or square root permeability ratio.

CONCLUSIONS

The following conclusions may be derived from these experiments:

1. The inclusion of CO_2 in the water imbibed into the rock matrix will improve the imbibition rate and recovery efficiency when compared to the imbibition process using formation brine.
2. The major factors affecting increased recovery using carbonated water include:
   a. increase in oil mobility.
   b. reduction of interfacial tension.

c. the introduction of a potential gas phase which may act as a solution-gas drive when the pressure is reduced below the bubble point.

3. The acidic nature of carbonated water increased the size of the pore throats in the carbonate cores.
4. Capillary retention of oil on the rock face is reduced when flooding with carbonated water.

ACKNOWLEDGEMENTS

The authors would like to thank the Crisman Institute for Petroleum Reservoir Management at Texas A&M University and the U.S. Department of Energy for providing funding for this research.

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Table 1 - Carbonated Water Imbibition and Blowdown Data - Sandstones

Permeability Air	Porosity	Oil Recovered			
		1 min	1 hr	1 day	3 days
(md)	(%)	(cc)			
420	20	0.1	0.2	0.4	0.7
76	17	0.1	0.2	0.6	0.7
460	20	0.2	0.4	0.8	1.1
805	22	1.0	1.5	1.8	2.0

Table 2 - Recovery From Sandstone Cores

Permeability Air	Porosity	Oil Recovered		Permeability to Oil	
		Brine	CO_2+Brine	Brine	CO_2+Brine
(md)	(%)	(% OOIP)		(md)	
420	20	30	36	42	57
76	17	21	29	44	60
460	20	35	35	121	136
805	22	38	38	142	152

Table 3 - Carbonated Water Imbibition and Blowdown Data - Limestones

Permeability Air	Porosity	Oil Recovered				
		1 min	1 hr	1 day	3 days	Evac
(md)	(%)	(cc)				
30	22	0	0.10	0.25	0.75	1.05
29	27	0.10	0.22	0.50	0.80	1.20
7	20	0.00	0.00	0.20	0.50	0.80
68	27	0.10	0.25	0.40	0.50	1.00

Table 4 - Recovery From Limestone Cores

Permeability Air	Porosity	Oil Recovered		Permeability to Oil	
		Brine	CO_2+Brine	Brine	CO_2+Brine
(md)	(%)	(% OOIP)		(md)	
30	22	25	35	3	10
29	27	10	24	9	15
7	20	16	32	<1	5
68	27	7	23	5	10

Permeability Air (md)	Porosity (%)	Oil Recovered (% OOIP) Brine	Oil Recovered (% OOIP) CO_2+Brine	Permeability to Oil (md) Brine	Permeability to Oil (md) CO_2+Brine
30	22	25	35	3	10
29	27	10	24	9	15
7	20	16	32	<1	5
68	27	7	23	5	10

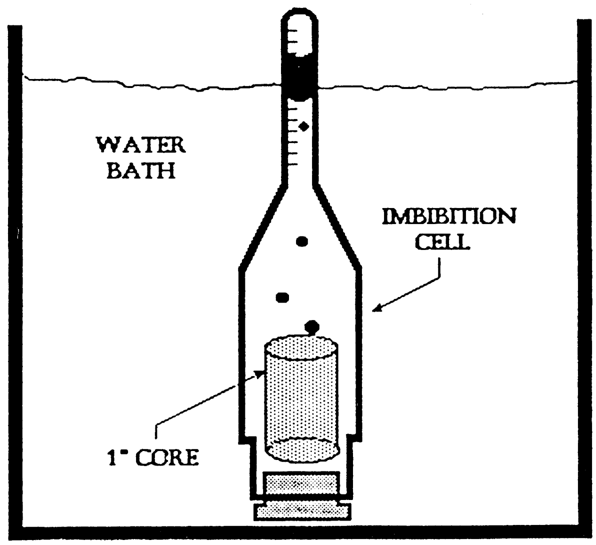

Fig. 1 - Visual Imbibition Chamber

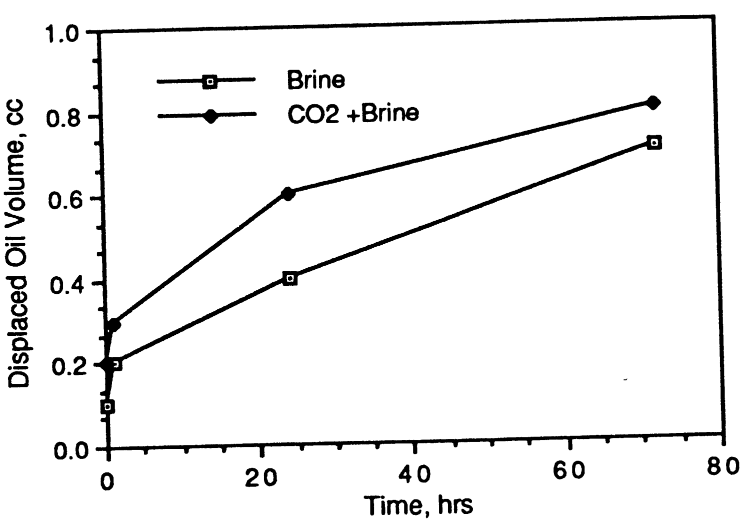

Fig. 2 - Cumulative Oil Displaced -Sandstone, 420 md

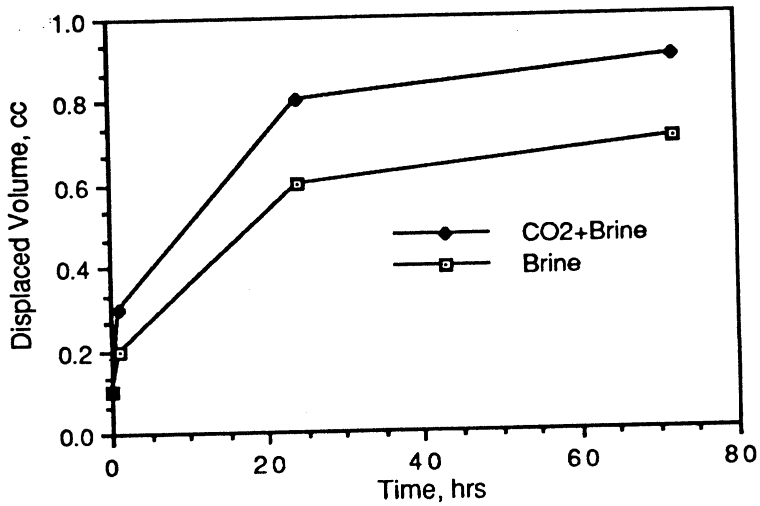

Fig. 3 - Cumulative Oil Displaced - Sandstone, 76 md

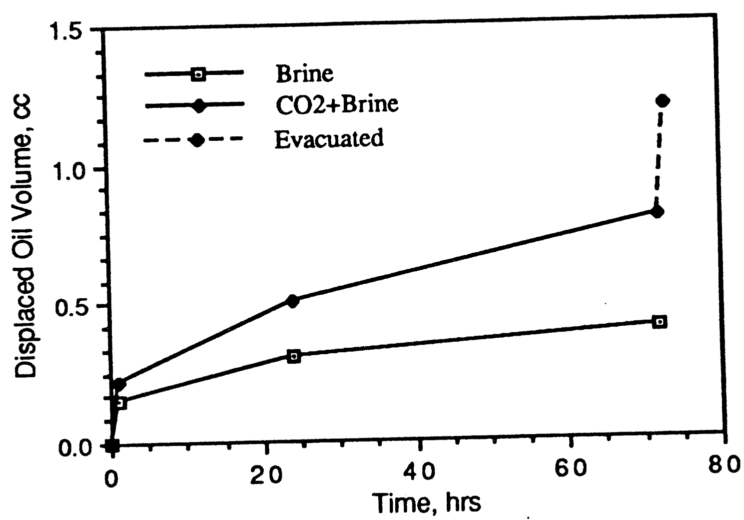

Fig. 4 - Cumulative Oil Displaced - Limestone, 29 md

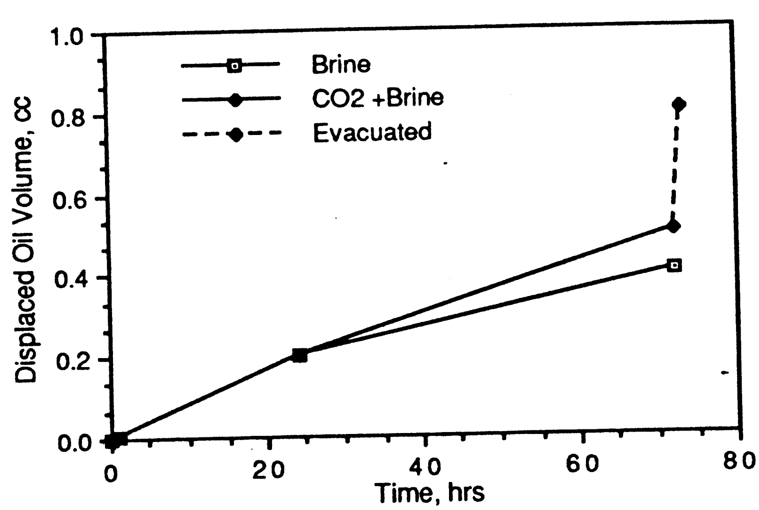

Fig. 5 - Cumulative Oil Displaced - Limestone, 7 md.

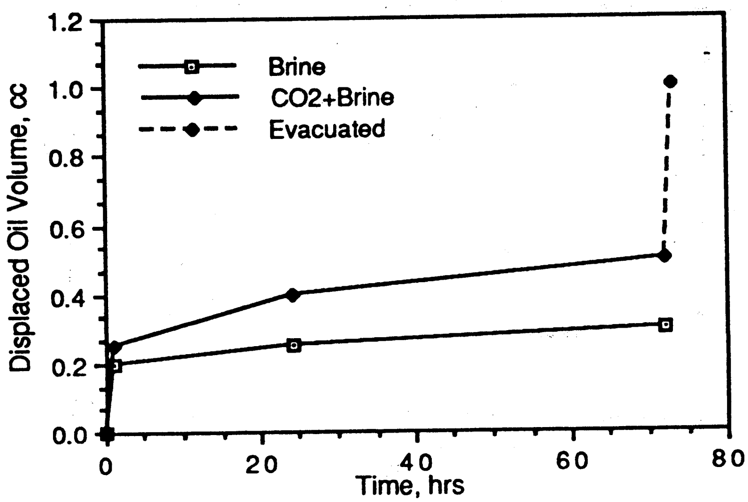

Fig. 6 - Cumulative Oil Displaced, Limestone, 68 md

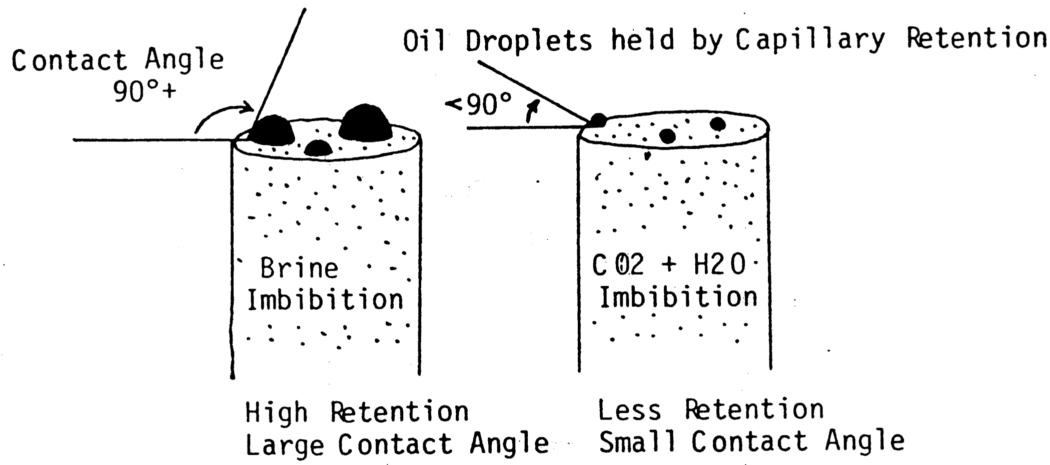

Fig. 7 - Capillary Retention Using Brine and Carbonated Water

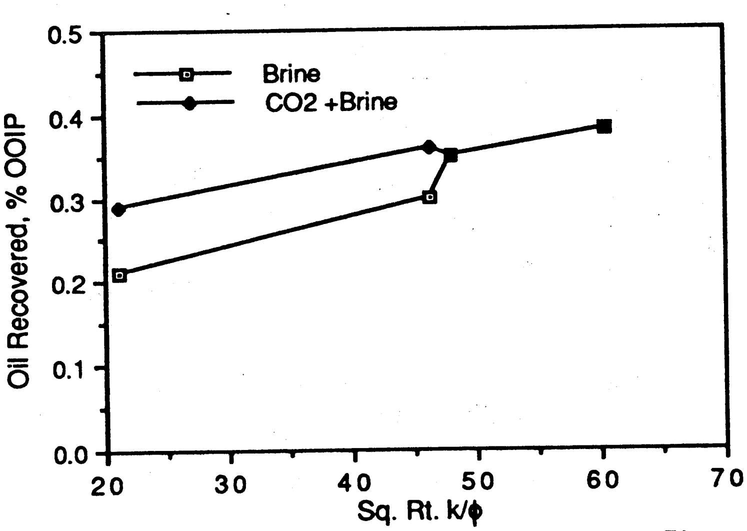

Fig. 8 - Sandstone, Graham and Richardson Plot

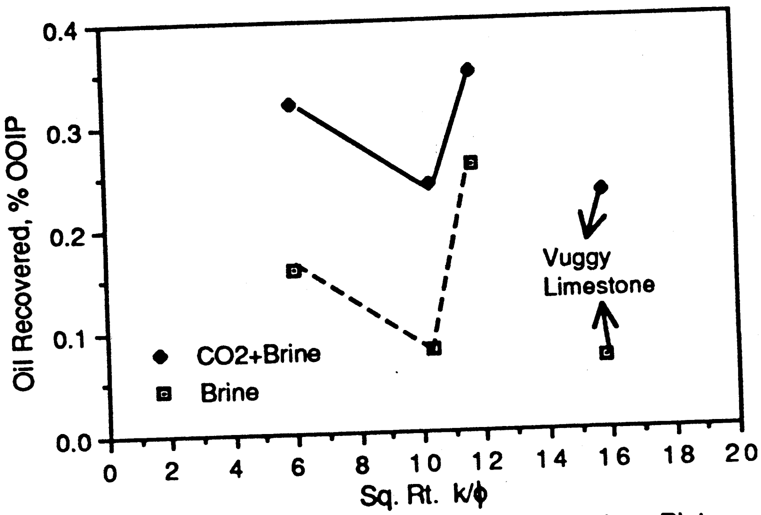

Fig. 9 - Limestone - Graham and Richardson Plot

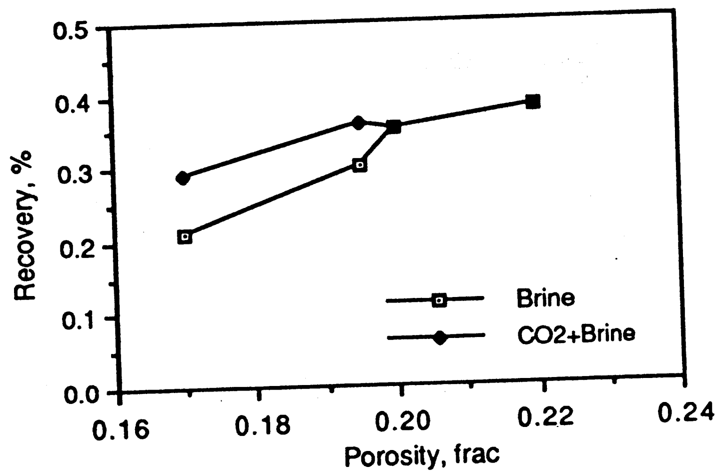

Fig. 10 - Sandstone, Torsaeter Plot

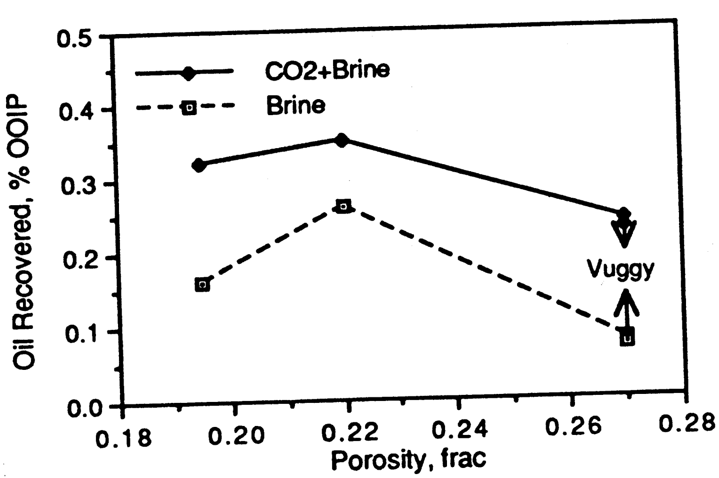

Fig. 11 - Limestone, Torsaeter Plot