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APPLICATIONS OF ADVANCED PETROLEUM PRODUCTION TECHNOLOGY AND WATER ALTERNATING GAS INJECTION FOR ENHANCED OIL RECOVERY - MATTOON OIL FIELD, ILLINOIS

COOPERATIVE AGREEMENT NUMBER DE - FC22 - 93BC14955

AMERICAN OIL RECOVERY, INC.
DECATUR, ILLINOIS

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OBJECTIVES

The objectives of this project are to continue reservoir characterization of the Cypress Sandstone; to identify and map facies-defined waterflood units (FDWS); and to design and implement water-alternating-gas (WAG) oil recovery utilizing carbon dioxide (CO_2). The producibility problems are permeability variation and poor sweep efficiency. Part 1 of the project focuses on the development of computer-generated geological and reservoir simulation models that will be used to select sites for the demonstration and implementation of CO_2 displacement programs in Part 2. Included in Part 1 is the site selection and drilling of an infill well, coring of the Cypress interval, and injectivity testing to gather information used to update the reservoir simulation model. Part 2 involves field implementation of WAG. Technology Transfer includes outreach activity such as seminars, workshops, and field trips.

SUMMARY OF TECHNICAL PROGRESS

DRILLING, GEOPHYSICAL AND PETROHYSICAL ANALYSES OF SEAMAN No. 15

A joint team of American Oil Recovery, Inc. project personnel and ISGS geoscientists selected Section 35, T12N R7E for location of the infill well, AOR/Seaman No. 15 based on the isopach of the target facies-defined subunit ("E"-interval) in the Sawyer Unit and information from surrounding wells (fig. 3). AOR/Seaman No. 15 was drilled from 9/12/93 to 9/22/93. The whole cores recovered from 1738' to 1822.5' contained live oil in the "B", "C" and "E" intervals of Cypress Formation (fig.1). Core analyses showed that the "E"-interval has a higher average porosity and permeability than the "B"- and "C"-intervals respectively (Table 1). A suite of geophysical logs comprising of *dual induction focus log, natural gamma ray log, compensated densilog/caliper, compensated neutron log, minilog, dielectric log and analysis and epilog - complex reservoir analysis* were run. The in-situ water saturation of the "E"-interval predicted from the logs were very high. For example, the C-interval was calculated to have a water saturation of 100% by the dielectric log despite the fact that the whole core portion of C-interval was observed to be oil saturated and bleeding oil and gas. Because of the uncertainty of the water saturations determined by use of "rule-of-thumb" values of exponent "n" and the formation cementation factor "m" employed in the log interpretation, Cypress core samples from the B-, C- and E- intervals were submitted for an extended analysis of these critical factors.

CYPRESS ROCK/INJECTED BRINE COMPATIBILITY TESTS

Two core plugs taken from the E-interval at depths of 1750.5 and 1751 feet respectively were tested for compatibility with (1) Cypress formation brine from Strohl No. 8, (2) produced brine from the Pennsylvanian formations, (3) pit brine consisting of Rosiclare and Cypress effluents, effluents from Pennsyvlanian formations and rain water, and (4) laboratory brine consisting of 1% NH4Cl and 1% NaCl. The resistivity and pH of the various test brines were measured at room temperatures ranging from 74.9°F to 77.3°F (Table 2). The fluids were injected into the plugs in the order shown in Table 3.

All field brines were first passed through the Whatman filter (No. 4) paper prior to injection into the core plug. The brines retained a yellowish taint after filtration. Liquid permeability was observed to decrease as the field brines were consecutively injected into the core plugs (Table 3). Also the color of the core effluents was clear suggesting that the plugs filtered out the yellowish taint. A dark-brown solid buildup was also observed on the inlet face of the core plugs. The liquid permeability increased from 14 md to 19.3 md after the flow direction was reversed in plug No. 2 (Table 3), a sure indication that particle plugging occurred in the core sample. These observations suggest that these field brines may impair formation permeability if injected into the reservoir without adequate filtration.

SLIM-TUBE CO_2-OIL MISCIBILITY TESTS TO DETERMINE MMP OF CYPRESS OIL

CO_2-crude oil miscibility tests were conducted in a slim-tube apparatus using Cypress crude oil sampled from the No. 8 Strong well (fig. 3). The test conditions were 85 °F and pressure ranges of 1250 psig to 2500 psig. The slim-tube properties are summarized in Table 4 and the test results are summarized in Table 5. The plot of oil recovery at 1.2 PV of injected CO_2 versus pressure is illustrated in Figure 2. The minimum miscibility pressure of the Mattoon crude oil with CO_2 was determined to be 1780 psig using the method of Yellig and Metcalf (1978).

The above result implies that only immiscible CO_2 displacement of oil is possible from the Cypress reservoirs at Mattoon field since the formation parting pressure is about 1,800 psia.

RESERVOIR SIMULATION

Reservoir simulation models of the Mattoon CO_2 Project have been developed to enhance and verify reservoir characterization, and to predict optimum CO_2-assisted oil recovery processes. The models, which are being continously updated, will aid in the design and management of Part 2 of this project. The three major models are: the Sawyer CO_2 Injection, the Pinnell CO_2-WAG, and the "huff 'n' puff" (cyclic CO_2 injection using data from the AOR/Seaman No. 15 well) models.

Sawyer Unit CO_2 Project

During the last quarter, approximately 2000 tons of CO_2 were injected into No. 1 Sawyer Community and oil produced from No. 2 Ed. Morris and No. 1 D.M. Sawyer Community 2 (fig. 3). ICCR No. 18 and ICCR No. 19 wells were monitored and found to contain CO_2. After the cessation of CO_2 injection on June 30, 1993, ICCR No. 18 and ICCR No. 19 wells and No. 1 Sawyer Community injection well were used to monitor reservoir pressure. There was a general pressure decrease in all these wells as oil production continued from No. 2 Ed. Morris and No. 1 D. M. Sawyer Community wells (fig. 4). Uniformity of pressure responses confirm communication among these wells in the E-interval.

Continuing and extensive search for well information in this unit revealed that twelve wells were completed for oil production from the "E"-interval at various times between June 1946 and February 1962. Furthermore, four wells including the Railroad No. 18 well, previously used as water injectors, were open in the "E"-interval. Only three wells - No. 1 Sawyer Community #3, No. 1 Sawyer Community #2 and Railroad No. 19 - were opened in the "E"-interval during the current project. The implication of this finding is that the "E"-interval has been produced.

A compositional reservoir simulation model consisting of six pseudo-components (Table 6) was developed to assist in the management of the project in the Sawyer Unit. Reservoir description was initially accomplished by correlations of reservoir quality (clean sand distribution) to porosities and the permeability-porosity correlation of the Cypress sandstone. This data has been greatly improved by the core analysis of the AOR-Seaman No. 15 well in the Sawyer Unit. Pseudo-relative permeability data were replaced with laboratory-measured values using Cypress rock from the newly-drilled well, Cypress brine and CO_2-saturated crude oil. History match was greatly improved. One drawback is that there is no gas data to date and simulated gas production could not be matched by observed data.

Planned predictions using the simulation model include the comparison of the performances of multiple well oil production and gas injection to those of the cyclic CO_2 injection and oil production otherwise called 'huff and puff'. The uncertainty of the integrity of wells that are open in the "E"-interval and the high cost of verifying them favor 'huff and puff' operations in the Sawyer Unit.

Single Well Cyclic CO_2 Injection in Sawyer and Strong Units

Parameters affecting oil recoveries from "huff and puff" wells have been investigated by simulation of a single well model. The core analysis and well data of the AOR-Seaman No. 15 well were used in the simulation (Table 7). The parameters included in the sensistivity analysis are: the CO_2 slug size, the number of CO_2 injection cycles, the CO_2-oil mixing ratios, and permeability-thickness of the reservoir interval.

Simulated results show that the oil production rate increases after injecting CO_2 into the single well (fig. 5). Other results are (1) oil recovery increases with CO_2 slug size reaching a peak after 2% HCPV (7.64 MMSCF) is injected but declines between 2% HCPV and 3% HCPV; (2) increasing permeability values also increases oil recovery and also cumulative gas production at the same slug size (fig. 6); (3) a second cycle of CO_2 injection may increase the oil flow rate at the same well conditions and (4) oil recovery increases with CO_2/crude oil mixing ratio (fig. 7). Other factors that increase the CO_2/crude oil mixing ratio include absence of thief zones in the reservoir, and initial reservoir pressure (fig. 2).

These results suggest that (1) there is a CO_2 slug size for optimum oil production from a given "huff and puff" well; (2) oil production from a "huff and puff" well may be optimized by well stimulation that can increase the well productivity without creating fractures and channels; and (3) a second cycle of CO_2 injection may enhance oil recovery from the "huff and puff" well.

The next stage of the simulation of the "huff and puff" process involves matching the simulation model to observed results from actual "huff and puff" wells in order to develop a suitable model that can be used to advise future applications of "huff and puff" projects.

Pinnell CO_2 WAG Project

The reservoir simulation study of the Pinnell CO_2-WAG project was performed using a black-oil model. The model was calibrated by matching oil production and pressure history between April 20 1993 and Sept. 30 1993. Performance of various CO_2 injection scenarios were investigated with Pinnell-Uphoff No. 1 and Pinnell No. 3-W wells as the oil producer and gas-water injector respectively. The options considered are:

(1) Base Case : Continuous production from Pinnell-Uphoff No. 1 without pressure maintenance after May 15.
(2) Straight CO_2 injection: Continuous CO_2 injection at a rate of 500 MCF per day.
(3) Straight water injection: Continuous water injection at a rate of 125 barrels per day.
(4) Water alternating CO_2 injection at various brine-to-CO_2 slug ratios.

The following conclusions can be drawn from the results of this model (Table 8):

(a) Oil production from WAG injection is higher than that obtained from straight CO_2 flood or straight water flood.
(b) Higher oil recovery was obtained with a WAG ratio higher than 1 MCF of CO2 per barrel of brine.
(c) Oil recovery by immiscible CO_2 displacment of oil is sensitive to the mixing ratio of CO_2 with crude oil. Oil recovery from straight CO_2 flood is poor when the mixing ratio is low (< 20%).

TABLE 1: CORE ANALYSIS SUMMARY

FORMATION	DEPTH feet	Average Permeability Horizontal md	Vertical md	Average ϕ %	Average Liquid Saturation, % Oil	Water
CYPRESS	1748.9 - 1758.0	61.0	57.0	19.6	15.3	25.2
	1777.8 - 1788.3	24.0	7.1	19.5	21.7	43.4
	1799.7 - 1810.8	11.0	0.93	16.7	10.6	37.9

Table 2: CHEMISTRY OF BRINE USED IN THE ROCK/BRINE COMPATIBILITY TESTS

Type of Fluid	pH	Rw,ohm/m2	TDS, ppm	Test Temp. F,
Cypress brine	6.97	0.074	37,768	74.9
Pennsylvanian[1]	7.54	0.113	20,804	77.3
Pit brine	6.85	0.110	21,652	77.0
Lab. brine	7.26	0.065	42,365	77.1
Core effluent from Cypress brine	7.36	0.076	35,400	76.3

Table 3: COREFLOW DATA IN THE ROCK/BRINE COMPATIBILITY TESTS

	Plug 1	Plug 2
Depth, ft	1750.5	1751.0
Air Permeability, md	45.2	42.7
Lab. brine perm., md	13.5	
Cypress brine perm., md		14.04
Pennsylvanian[1] brine perm. md	10.1	13.33
Pit brine perm., md	7.0	8.50
Reverse flow - Cypress brine perm., md		19.32

[1] Pennsylvanian brines consist of commingled produced brines from Pennsylvanian formations.

Table 4: **SLIM TUBE PROPERTIES**

Column material	316 stainless steel
Length	57 feet
Internal diameter	0.457 cm
Packing material	glass bead (100-120 mesh)
Porosity	42.1%
Pore volume	120 cc
Pressure rating	5000 psi
Permeability	4 darcies

Table 5: **OIL RECOVERIES AT VARIOUS SLIM TUBE PRESSURES**

Pressure (psig)	% oil recovery	% PV CO2 injected when gas oil interface/transition zone was observed
1350	74.86	72%
1500	81.67	79%
2000	90.01	91%
2500	91.40	95%

Table 6 - **PROPERTIES AND COMPOSITIONS OF PSEUDO-COMPONENTS IN RESERVOIR CRUDE OIL**

Reservoir Temperature = 80°F

Pseudo-component	Composition Mole fraction	Components in Mixture	Molecular Weight gm/gmmole	Critical temp.° °F	Critical Pressure psia
CO_2	0.0004	CO_2	44.01	87.9	1070
P2	0.0036	N_2	28.01	-232.4	493
P3	0.06253	C1,C2,C3	36.11	119.8	639.16
P4	0.08171	C4,C5	65.32	342.84	518.51
P5	0.3522	C6,C7,C8,C9	103.11	553.61	435.76
P6	0.49955	C10,C33	388.53	1104.7	212.15

Table 7 - RESERVOIR PROPERTIES USED IN SINGLE WELL SIMULATION (AOR/SEAMAN No. 15)

Average water saturation = 59% (assumed)
Oil saturation = 38 % "
Gas saturation = 3% "

	Permeability, md		
Depth, feet	Horizontal	Vertical	Porosity, %
1750	71.0	54.0	20.9
1750-1751	73.0		19.6
1751-1752	119.0		20.2
1752-1753	73.0	67.0	20.7
1753-1754	60.0		21.3
1754-1755	28.0		19.5
1755-1756	54.0	49.0	21.0
1756-1757	11.0		13.5
1757-1758	2.1		13.8

Table 8 - CUMULATIVE OIL PRODUCTION RATIO (RELATIVE TO BASE CASE)
FROM APRIL 20 1993 TO DEC 30 1995

	Mixing Ratio (% of HCPV contacted by CO2)		
	5%	20%	50%
CO2 flood	0.75	1.4	3.2
Brine flood	2.4	2.5	3.1
WAG (1:2)[2]	2.6	3.8	5.7
WAG (1:1)	2.6	3.7	5.0
WAG (2:1)	2.6	3.5	4.2
WAG (3:1)	2.6	3.2	3.8

(Ref: YELLIG. W.F. and METCALFE, R.S., Determination and prediction of CO2 minimum miscibility pressure :Paper SPE 7477. presented at the 53rd annual SPE technical conference and Exhibition, Houston, Texas October 1-3 ,1978)

[2]WAG (1:2) means water alternating gas ratio of 15,000 barrels of water to 30,000 MCF of CO_2)

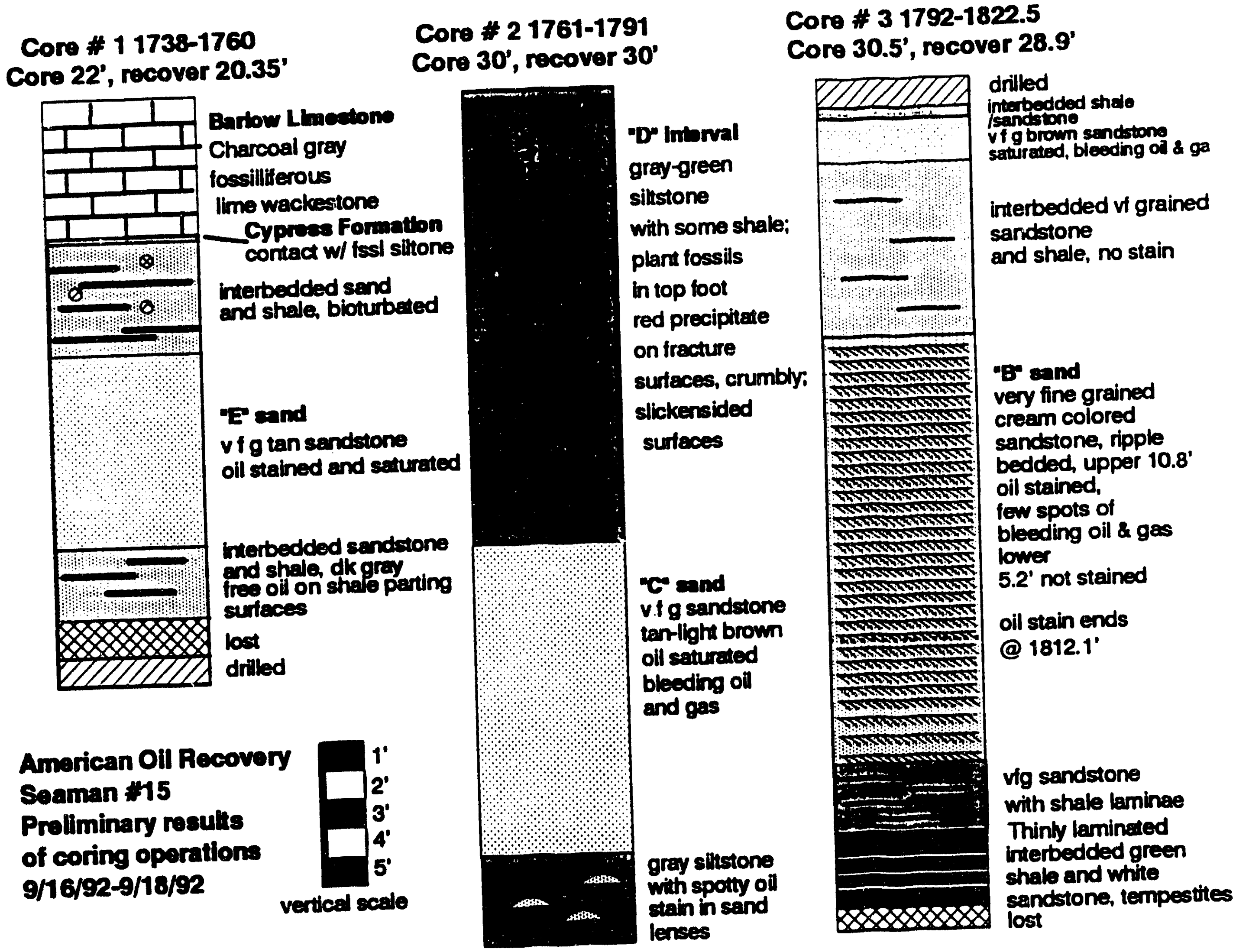


Figure 1: First-pass whole core description of Cypress interval from AOR/saeman No. 15 well

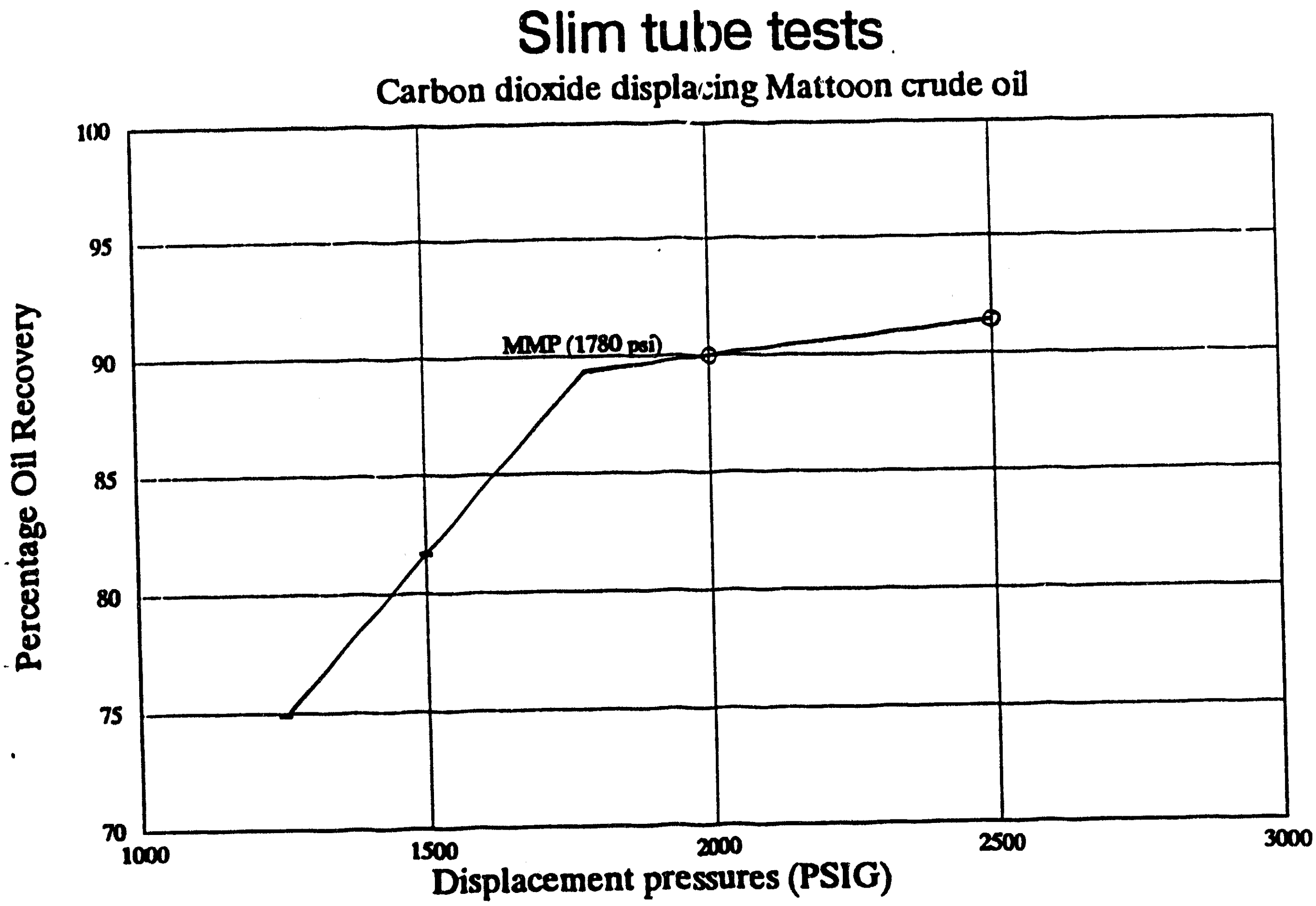
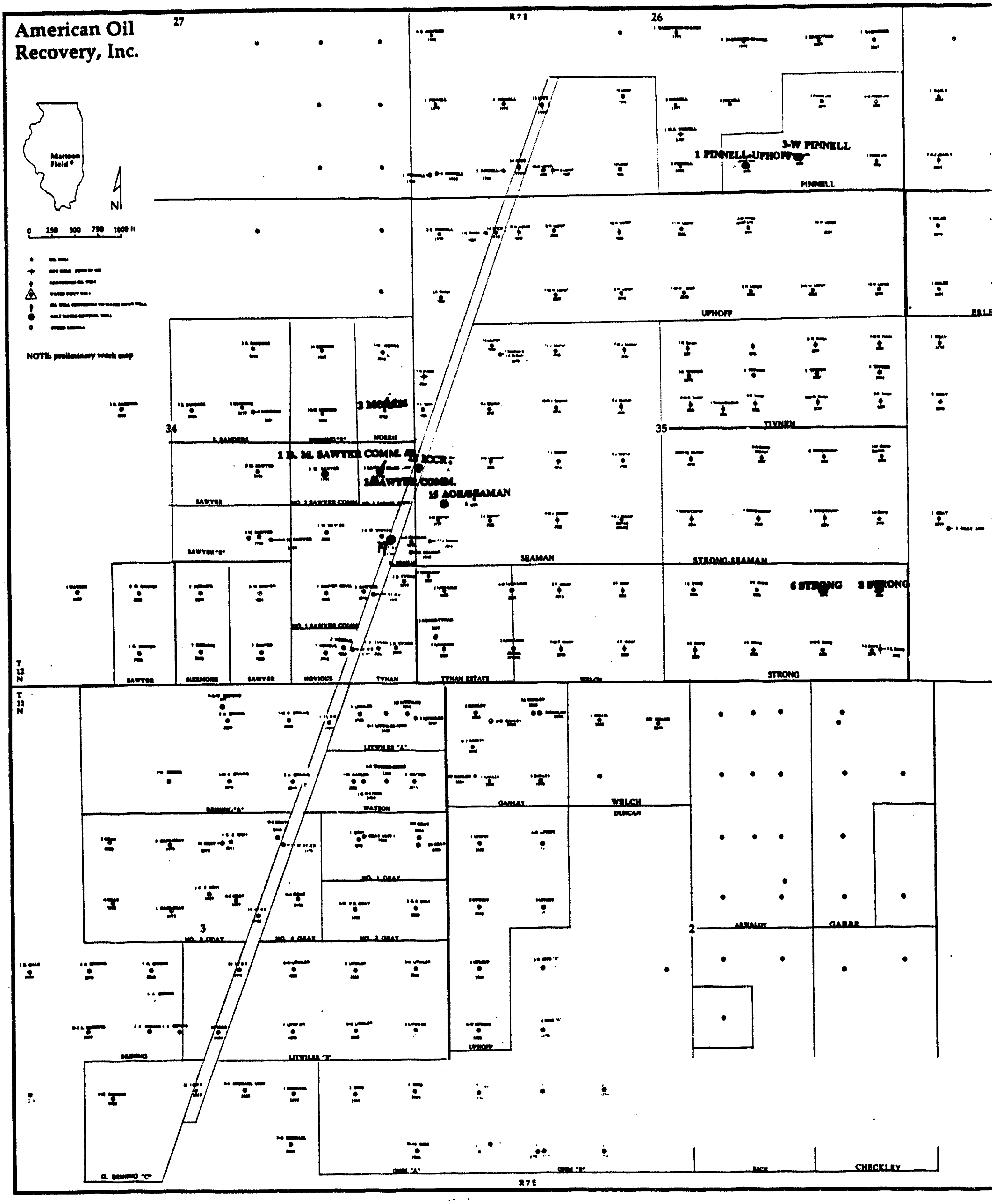


Figure 2: Percentage oil recovery versus displacement pressure from slim tube tests. the minimum miscibility pressure is 1780 psi. Miscible displacement of oil with CO_2 may only occur above this pressure.

Figure 3: Location map of the Mattoon CO2 Project area showing units.



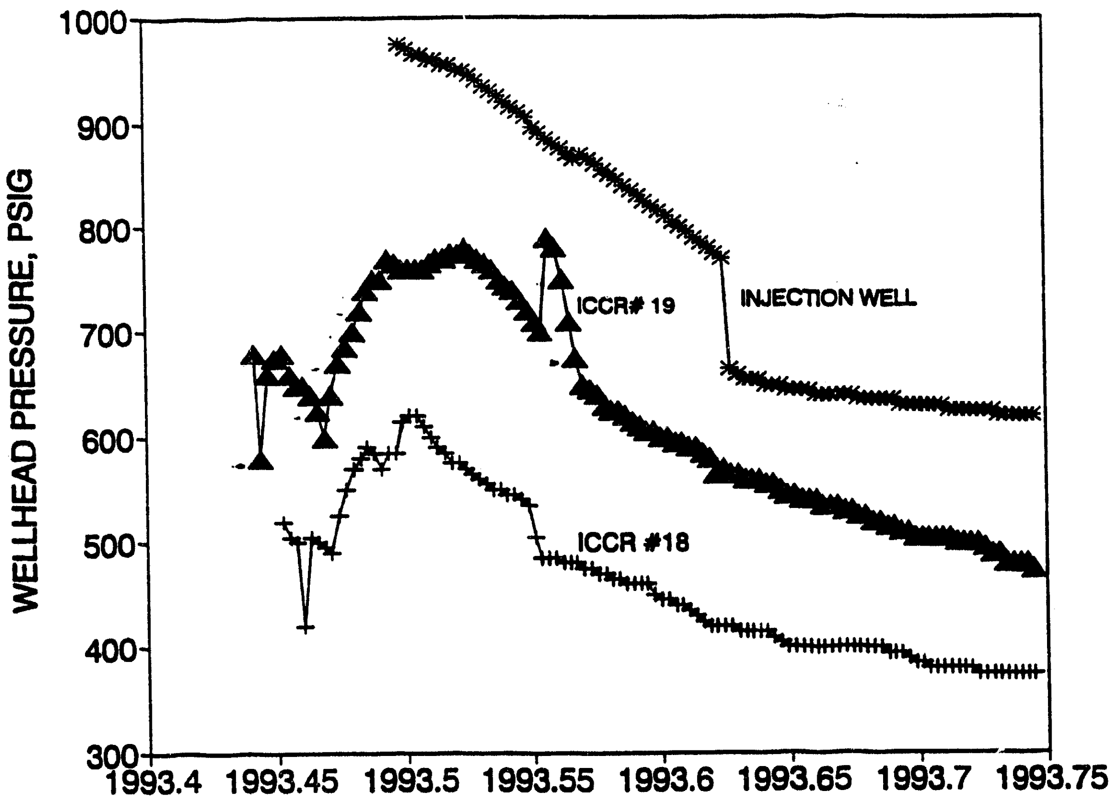


Figure 4: Wellhead pressures of injection well (Sawyer 1 Community 3), ICRR #18 and ICRR #19. Identical pressure profiles indicate communication among the wells.

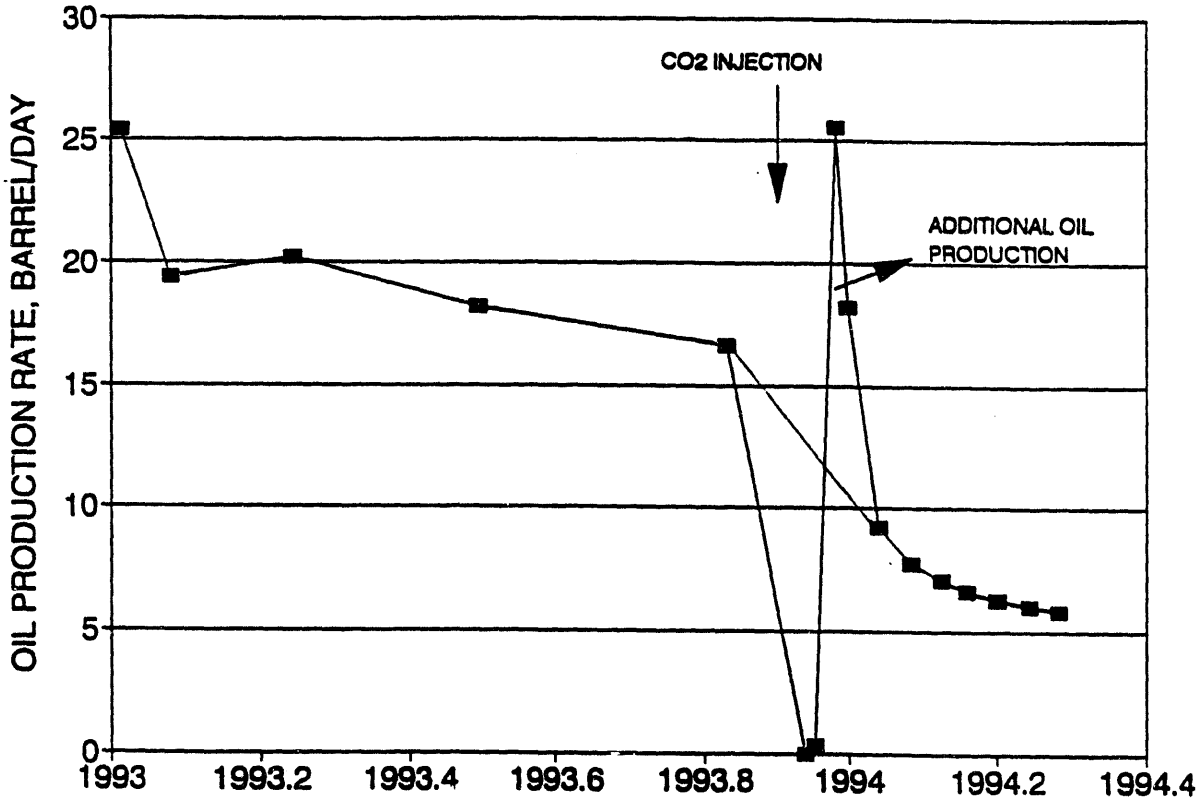


Figure 5: Oil Production rate is increased by the CO_2 cyclic injection processes. 3.82 MMSCF of CO_2 was injected into 10 feet of pay.

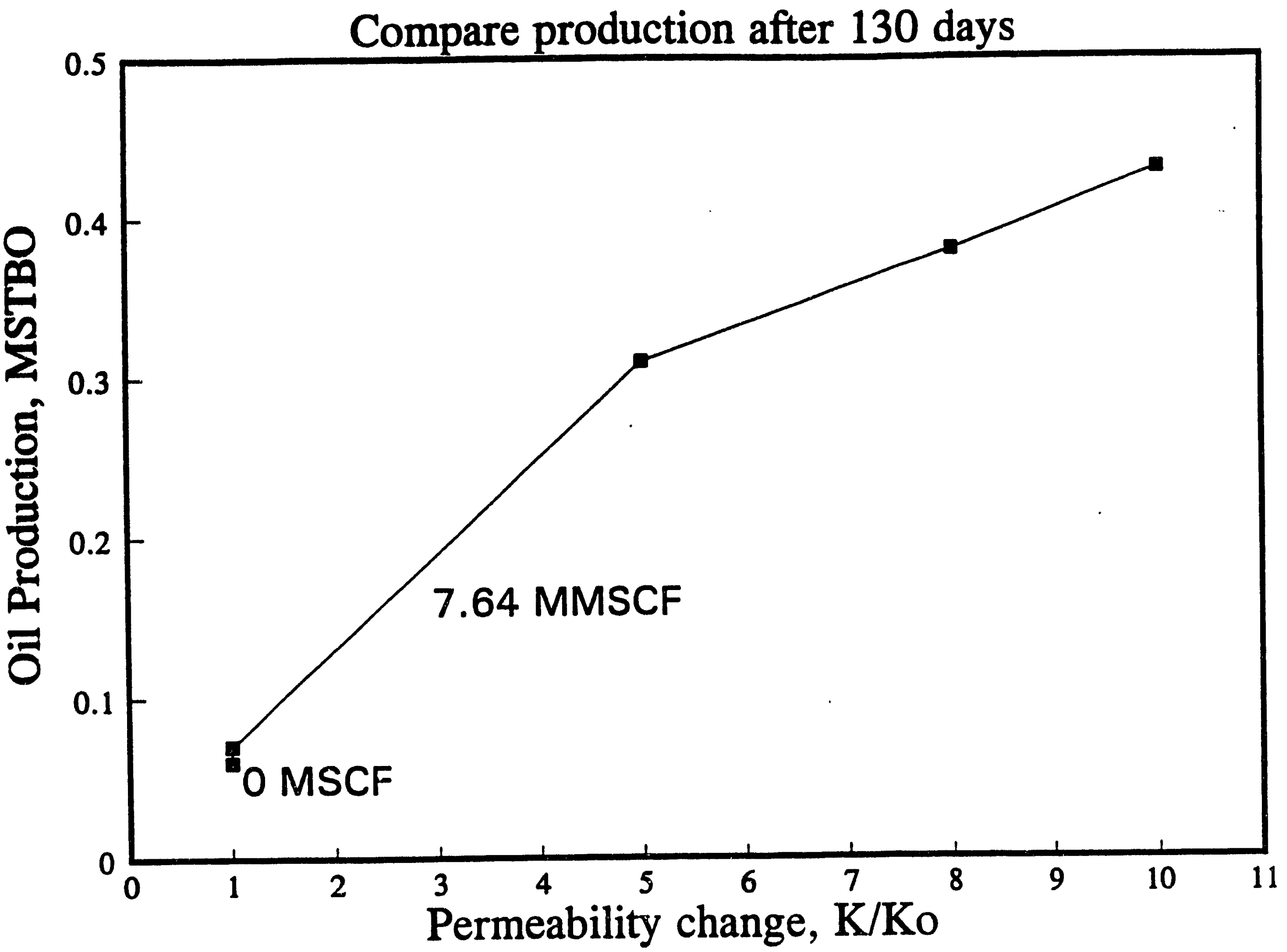


Figure 6: Oil recovery is enhanced with improved reservoir permeability.

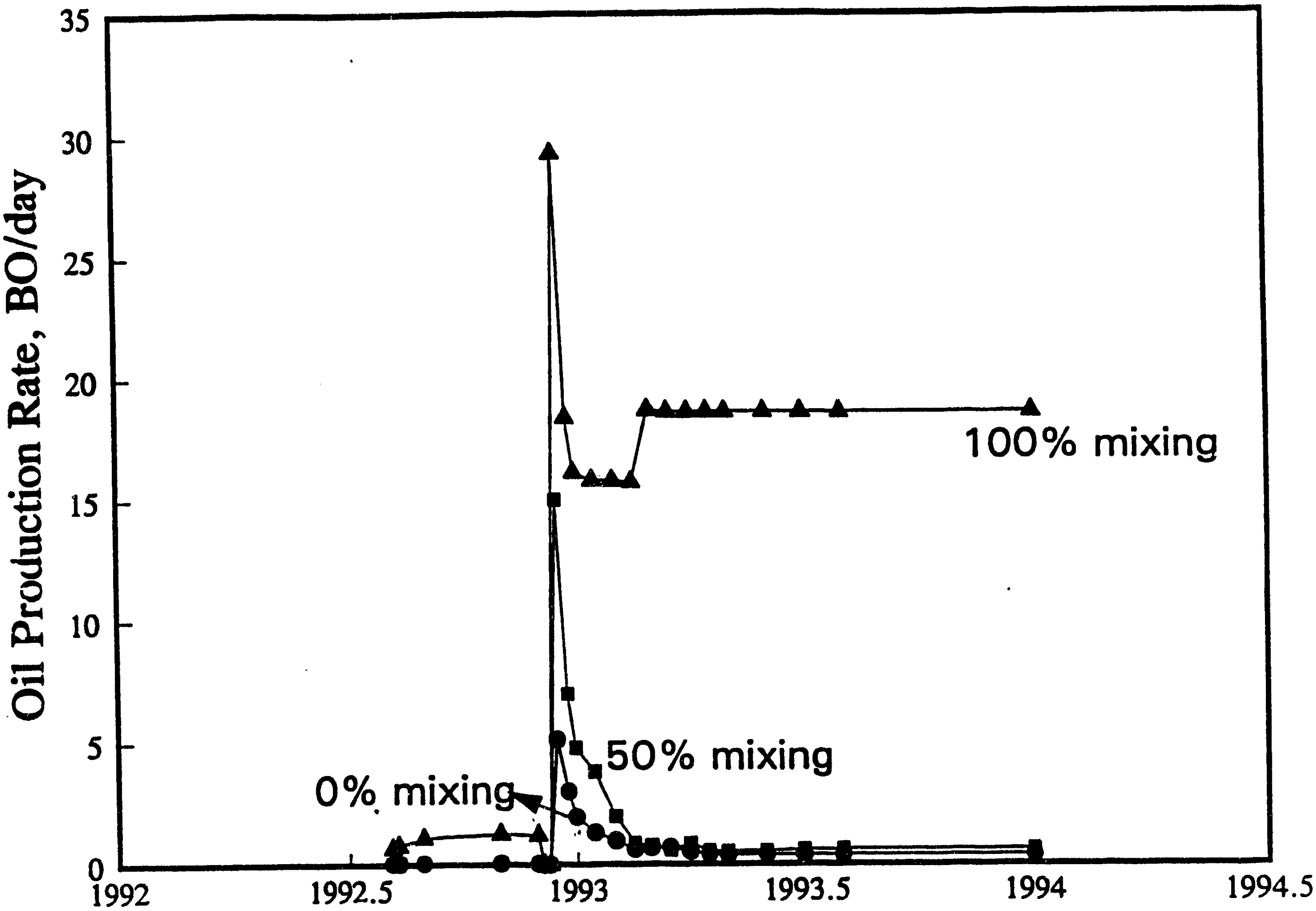


Figure 7: Oil recovery rate increases with increasing CO2-crude oil mixing ratio.

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