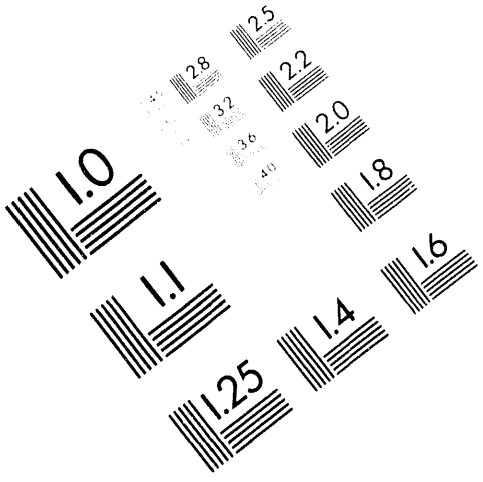

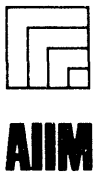

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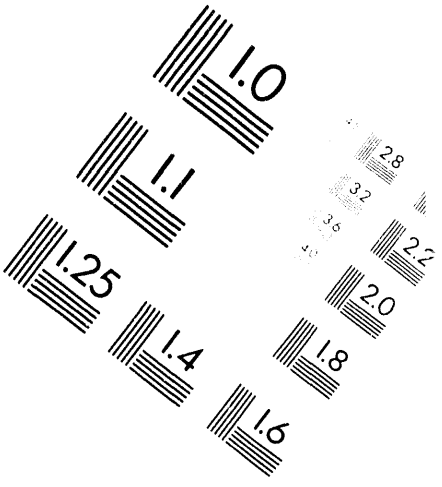

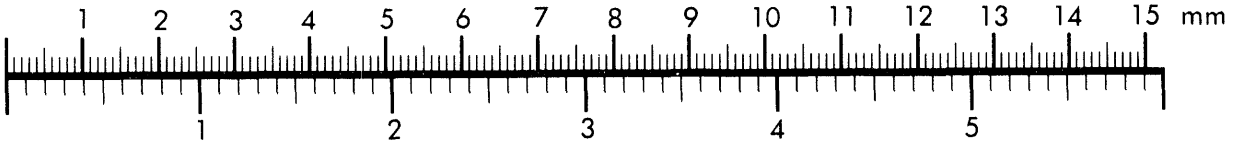

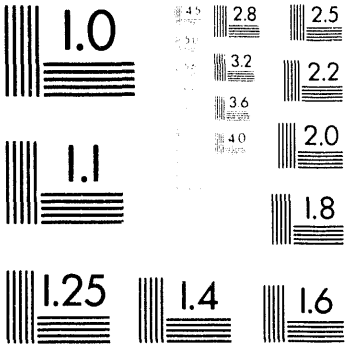

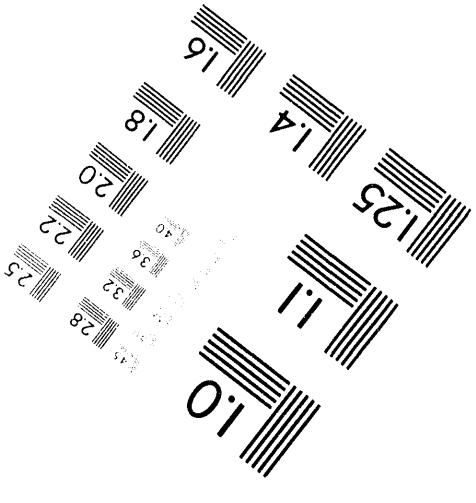

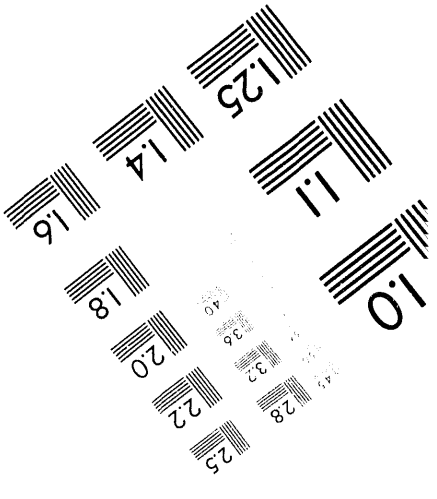

1 of 1

2nd Quarter, Fiscal Year 1994

POST WATERFLOOD CO2 MISCIBLE FLOOD IN LIGHT OIL, FLUVIAL - DOMINATED DELTAIC RESERVOIRS.

DE - FC22 - 93BC14960

TEXACO EXPLORATION AND PRODUCTION INC.

APRIL 29, 1994

Award Date: June 1, 1993.
Completion Date: December 31, 1997

Government Award for Current Fiscal Year

Project Manager (Texaco) Sami Bou-Mikael
COR (DOE) Chandra Nautiyal
Contract Specialist (DOE) John Augustine

Reporting Period : January 1, 1994 Thru March 31, 1994

U.S./DOE Patent Clearence is not required prior to the publication of this document

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TABLE OF CONTENTS

	Page
Executive Summary	1
Second Quarter Objectives 1994	1
Discussion of Results - Field Implementation	3
Discussion of Results - Technology Transfer	4
Third Quarter Objectives 1994	4
Figures: 1 - Field Map	5
2 - Field production	6
3 - New Grid Map	7
Management Summary Report removed	8
Milestone Schedule removed	9
Milestone Schedule Attachment removed	10
Financial Status Report removed	11
Federal Cash Transaction Report removed	12
Appendices: A - SPE Paper "Project Design of a CO2 Miscible Flood in a Waterflooded Sandstone Reservoir".	13
B - SPE Paper " A Stream tube Model for the PC".	27

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POST WATERFLOOD CO_2 MISCIBLE FLOOD IN LIGHT OIL

FLUVIAL DOMINATED DELTAIC RESERVOIRS"

"DE-FC22-93BC14960"

TECHNICAL PROGRESS REPORT
2nd QUARTER, 1994.

EXECUTIVE SUMMARY.

Production resumed from the Port Neches CO_2 project on December 6, 1993, after a 75 days shut in period. Since that date production is continuing to improve on various wells that responded to CO_2 injection. Current production is averaging 325 BOPD from 3 wells. This represents 4 folds increase from the production level prior to commencing CO_2 injection. Texaco continue to purchase an average of 4.3 MMCF/D of CO_2 from Cardox. The reservoir pressure increased with CO_2 injection from 2460 psi in September 1993 to 3328 psi in January 1994. However, the reservoir pressure declined slightly since then to 2730 psi in March of this year because of reservoir imbalance due to downtime at the CO_2 source. Currently, CO_2 is being injected in 3 wells in the reservoir including the horizontal well drilled specifically for this purpose. The well, through its 250 ft horizontal section, is capable of taking all the available CO_2 volume. However, injection rate in the well is restricted in order to distribute the CO_2 evenly in the reservoir.

Texaco is continuing its efforts to transfer this technology to other operators by presenting two papers at the SPE/DOE symposium that was held on April 17-20, 1994, in Tulsa, Oklahoma. one paper will discuss reservoir Characterization and project design, while the other paper will discuss the development of the screening model. This model is scheduled for release to the public in 1994, it will be a very useful screening and design tool for the industry. A topical report covering the environmental regulations and constrains related to the implementation of similar projects, will be released later this year.

2nd QUARTER (1994) OBJECTIVES.

The objectives for the second quarter of 1994 as stated in the first quarterly report and their status are as follow:

* Improve the reservoir model by incorporating new grid and provide results in the next quarterly report.

The reservoir model was updated based on the 3-D seismic survey evaluation. A fault was placed in the center of the reservoir. The grid has been rotated to accommodate this change, and a finer 29*72*1 grid system shown in Figure 1, has been reconstructed. The reservoir volumetrics did not change. The OOIP and OGIP are 10.4 MMSTB and 4.5 BCF. Several runs were made to history match the reservoir primary production. The results clearly indicates the need of an aquifer support in order to match the reservoir production and pressure. The highest oil saturation is present in the updip portion of the reservoir. This is supported by the high rate of oil production from well # 15-R, attributed mostly to movable oil present in the reservoir.

Simulation runs made with the presence of an aquifer influx resulted in a cumulative primary production of 5.08 MMSTBO and 5.87 MMSTBW and 4.12 BCF. This is below the actual reservoir production, requiring an adjustment of permeability data and aquifer strength. The prediction runs indicate higher recovery than actually observed in the field.

In order to improve the current reservoir model, Texaco intends to develop a strata model based on 3-D seismic and other pertinent reservoir data, and utilize the results of the strata model to improve the current compositional model.

* Complete SPE paper for the SPE/DOE Improved Oil recovery symposium, and include a draft copy in the next quarterly report.

As stated above two SPE papers have been prepared and presented at the SAPE/DOE symposium on April 17-20, 1994 in Tulsa, Oklahoma. A draft copy of each paper is included with this report in appendices A and B.

* Establish CO_2 injection into the horizontal well and production from the remaining producers.

The horizontal CO_2 injection well (Marg. Area 1, 1-H) was drilled and completed in the subject reservoir, and CO_2 injection has been established in the well. The 250 ft horizontal section is capable of taking the entire 4300 MCF/D of CO_2 available for injection. However, the rate has been restricted to an average of 1500 MCF/D in order to distribute the CO_2 volume evenly in the reservoir.

Production response to date, has been slightly higher than anticipated, as a result of the CO_2 and water injection. The average initial reservoir yield, estimated at 100 BO/MMCF is consistent with the performance of other projects conducted is similar sandstone reservoirs. The yield will be recalculated shortly when a new software, capable of accurately measuring

gaseous CO_2 production, is installed in the field. This software is being developed by the supplier to handle a wider range of gas density that will cover CO_2. The actual and the forecasted production vs. time are shown in figure 2. We anticipate this production trend to continue with continuing CO_2 injection.

* Modify CO_2 injection patterns to allow for optimum CO_2 utilization. Incorporate a standard WAG injection process if necessary.

CO_2 and water injection continued into the Port Neches (Marg - area 1) at a quarterly average rate of 2716 MCF/D and 753 BW/D. This reduced CO_2 rate was due to downtime at the Dupont plant during the month of February, and repairs done on the water injection pump. The CO_2 was injected into wells # 7, 10, 36 and 1-H as shown in figure 3, while water injection continued in well # 17 only. Texaco is attempting to maintain high reservoir pressure in order to maximize production. We will be evaluating the need to install additional pumping capacity in order to handle high water production rates. Also We are currently evaluating the conversion of well # 10 to water injection since well # 17 will not be able to take all the produced water at the higher reservoir pressure. Converting well # 10 to an injector will allow us to contain the CO_2 in the inner portion of the reservoir, near the producing wells.

DISCUSSION OF RESULTS - FIELD IMPLEMENTATION.

The Port Neches project implementation phase is nearly complete, including facilities installation, workovers and drilling of new wells. Exceptions to this is the drilling and workover of two wells in project area 2, that were delayed until early 1995. CO_2 and water injection is progressing as scheduled in order to achieve and maintain a reservoir pressure at or above the MMP of 3300 psi. A reservoir pressure of 3328 psi was reached in January 1994. However, This pressure has declined slightly since then to 2730 psi in March 1994 because of reservoir withdrawal rate exceeded the injection rate. This situation was remedied once the CO_2 source at Dupont plant was back on line during the month of March. Additional steps may have to be taken to increase the water injection capacity if required based on project performance.

The following is a list of the most recent well tests taken on April 5, 1994 for all producing and injection wells:

Producing:

Khun	#15-R,	252	BOPD,	1686	BWPD,	3492	MCFD,	35/64	CK,	600# TBG.
Khun	#38 ,	57	BOPD,	320	BWPD,	154	MCFD,	18/64	CK,	140# TBG.
Khun	#33 ,	4	BOPD,	48	BWPD,	7	MCFD,	12/64	CK,	210# TBG.
Stark	#8 ,	14	BOPD,	146	BWPD,	730	MCFD,	12/64	CK,	710# TBG.

Injection:

Marg area 1 #1-H,	2197 MCFD,	1090 # TBG,	14/64 CK.
Stark #7 ,	2769 MCFD,	1094 # TBG,	48/64 CK.
Khun #36 ,	2586 MCFD,	1092 # TBG,	8/64 CK.
Khun #17 ,	1343 BWPD,	1910 # TBG,	OL.

Other wells are anticipated to respond to CO_2 injection as we continue fill up the reservoir with CO2. Peak performance is anticipated by early 1995, as predicted by various reservoir models.

DISCUSSION OF RESULTS - TECHNOLOGY TRANSFER.

As stated in the previous quarterly report in addition to Texaco releasing a screening and design program for CO_2 projects, other technology transfer work are being conducted by Louisiana State University (LSU) and Science Applications International Corporation (SAIC). LSU is gathering information on Fluvial Dominated Deltaic Reservoirs, using the Louisiana office of Conservation's data base, to assemble production and reservoir data to estimate recoverable tertiary reserves from such reservoirs, using Texaco's reserves estimation method. the LSU

data base was provided in the first 1994 quarterly report. Also SAIC is working on a topical report to address the environmental regulations and constrains facing projects of this type, some of which occurred during the Port Neches project implementation. This report will be ready for publication later this year.

3rd QUARTER (1994) OBJECTIVES.

* Continue CO_2 Injection in all wells in order to distribute the gas in the reservoir and allow maximum contact with the reservoir oil. Contacting the reservoir oil is the key to achieve maximum recovery and optimize the project economics.

* Monitor production response, reservoir pressure, oil and gas analysis, water injection and radioactive tracers to optimize production and to build a more effective reservoir model.

* Continue our modeling efforts to improve the compositional model to reexamine the reservoir description used in the model to take into account the heterogeneity of the reservoir in permeability, porosity and sand distribution. Create a Strata Model to improve reservoir characterization, and eventually to improve the reservoir compositional model.

newgrid:Layer 1/Structure (Top)

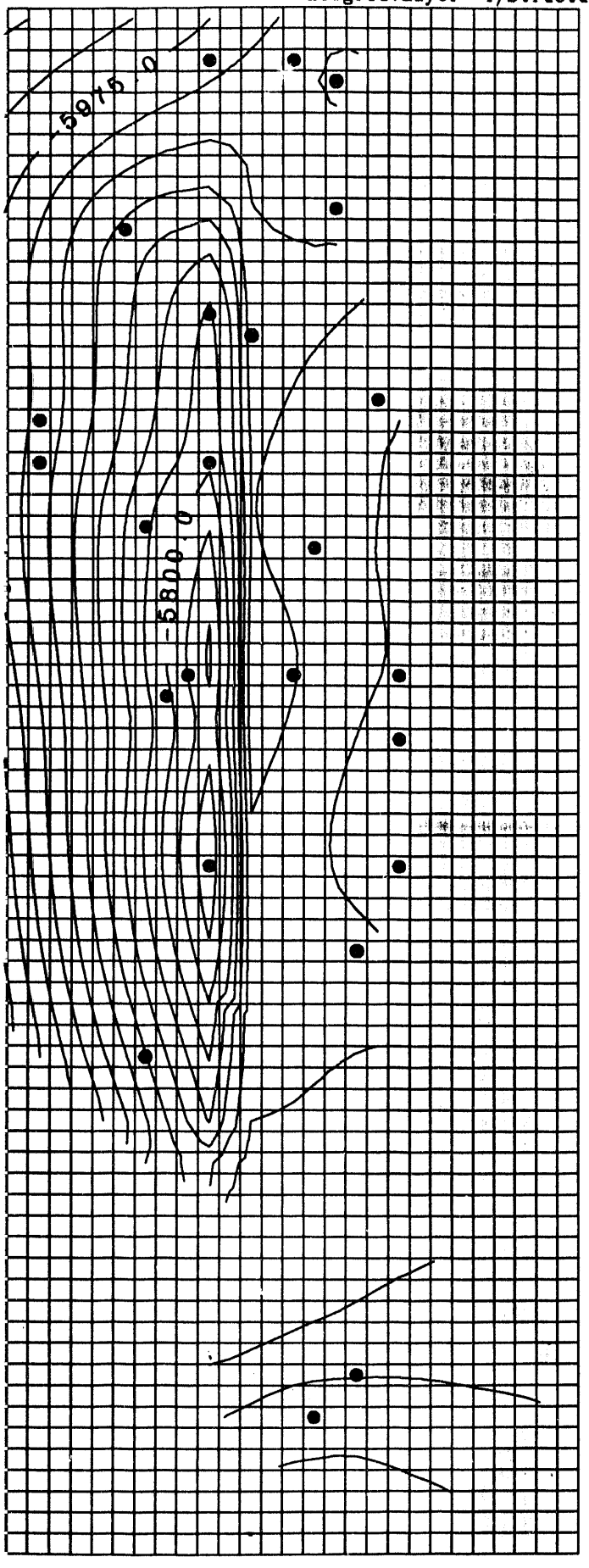

Figure 1

Port Neches CO2 Project
Allocated Production

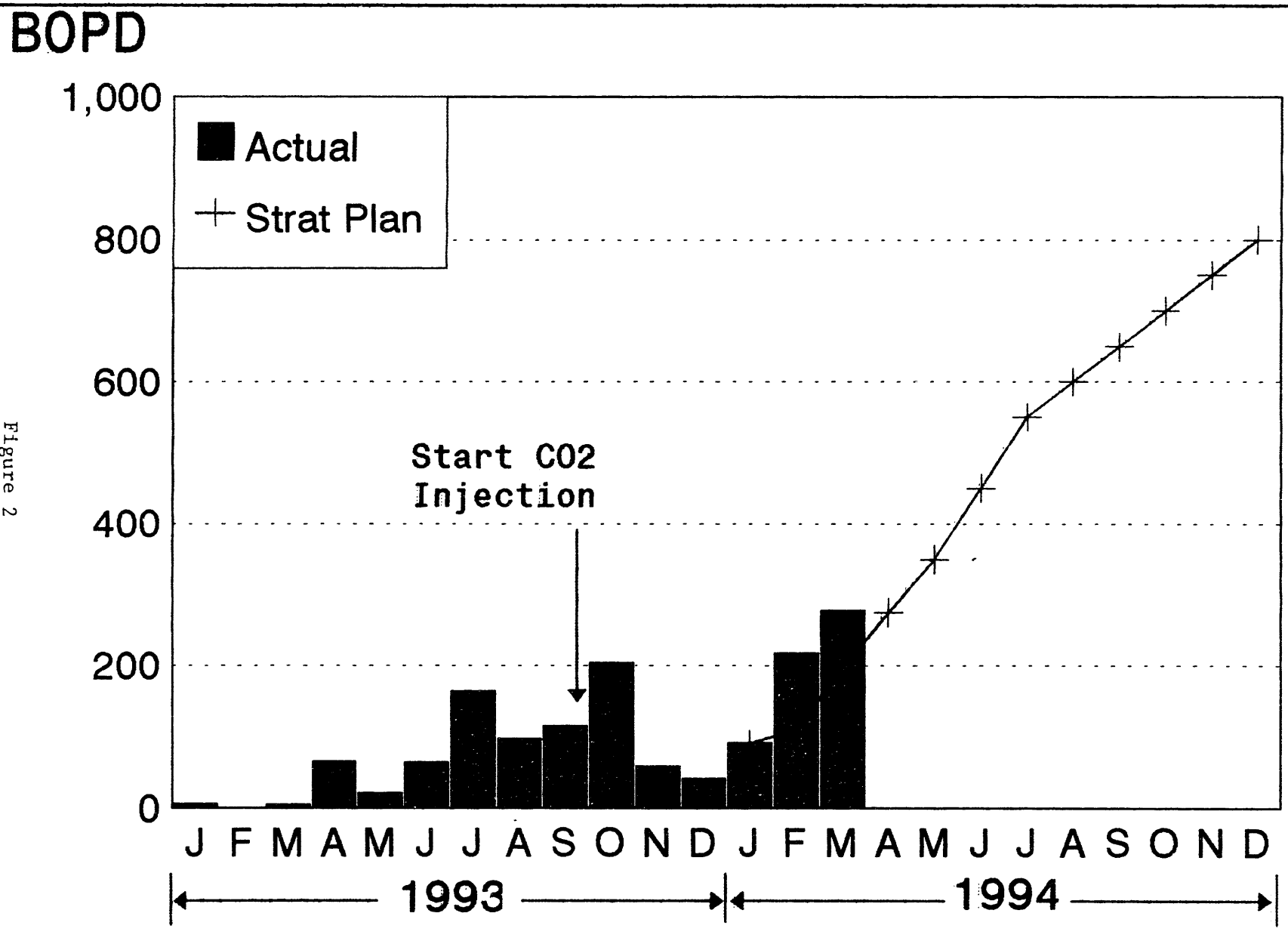

Figure 2

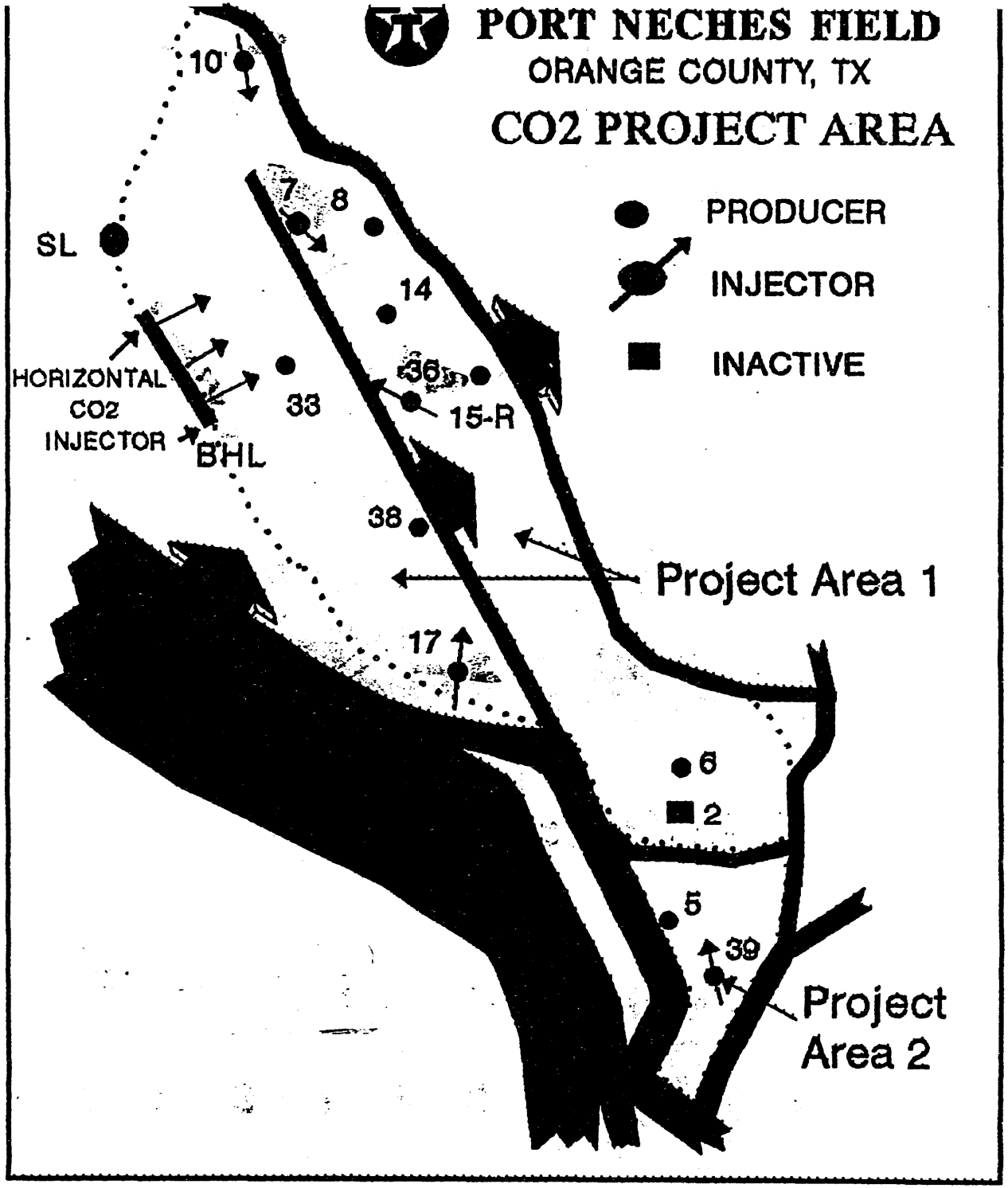
PORT NECHES FIELD
ORANGE COUNTY, TX
CO2 PROJECT AREA
PRODUCER
INJECTOR
INACTIVE
10
7
8
SL
14
HORIZONTAL
CO2
INJECTOR
33
36
15-R
BHL
38
Project Area 1
17
6
2
5
39
Project
Area 2

Figure 3

Appendix A

ABSTRACT

The Port Neches CO_2 miscible flood project began CO_2 injection in September, 1993 into a waterflooded sandstone reservoir along the Texas Gulf Coast. Sponsored by the U.S. Department of Energy (DOE) in their Class I Oil Program, this project will determine the recovery efficiency of CO_2 flooding a sandstone reservoir which has been extensively waterflooded down to a residual oil saturation of 30%. The design of this project utilized the various tools available for predicting the recovery performance of such projects, with DOE's CO_2 Predictive Model CO_2PM[1] and a compositional model being used. In addition a streamtube model[2,3] has been developed to predict the recoveries associated with the waterflood and CO_2 recovery processes. The validity of this streamtube model, the CO_2PM program, and previous compositional reservoir simulation work, has been evaluated by the use of a compositional five-spot model where an equation-of-state for the current reservoir oil is incorporated. This work points out the streamtube model's ability as an effective screening device for CO_2 flood prediction. Furthermore, the importance of properly characterizing the permeability within each layer of the reservoir is demonstrated by the improved recoveries seen in fining-upward sequence reservoirs.

References and illustrations are at the end of paper.

INTRODUCTION

The Port Neches Field, located in Orange County, Texas, was discovered during 1929 near the historic Spindletop oil field between Beaumont and Port Arthur, Texas. In 1934 the Marginulina sandstone reservoir was encountered at a depth of approximately 5900 feet and the oil zone was rapidly developed by infill drilling.

As shown in Figure 1, the sand has two project areas where a CO_2 miscible flood will be conducted. The upper fault block is approximately 235 acres in size and has an average thickness of 30 feet. This segment of the sand underwent pressure depletion during primary production from 2700 psi original reservoir pressure down to below 100 psi by 1965. At this time, the reservoir had produced 4.2 million barrels of oil (MMBO), 40% of the 10.4 MMBO original oil in place (OOIP), and a waterflood was initiated. An additional 1.5 MMBO, (14% OOIP), has been produced from the sand as a result of this operation. Analysis of open-hole logs from two sidetracked wells obtained during 1993 and high watercuts from producing wells, indicate that this reservoir is very near its residual oil saturation of 30%. A miscible CO_2 flood is currently being conducted to extend the life of the reservoir and will attempt to recover an additional 19% OOIP by applying this tertiary process.

Due to the proximity of an industrial CO_2 source, the

Port Neches Field was selected as a site where enhanced oil recovery using CO_2 injection could be performed. The Marginulina sandstone reservoir was determined to be the best candidate due to its light oil properties and moderate depth. A laboratory slimtube test performed on the 34.6° API crude oil indicates that the minimum miscibility pressure (MMP) for the oil is 3310 psia, which is 1460 psia above its waterflood operating pressure of 1850 psia. The reservoir was pressured up with water and CO_2, and is currently operating at a reservoir pressure of 3350 psia. A horizontal well has been drilled along the reservoir's original oil-water contact and has a 250 foot horizontal section. Production from the reservoir has increased from 80 barrels of oil per day (BOPD) to 250 BOPD. Peak production of 800 BOPD is anticipated during 1995.

PROJECT DESIGN

In the design of the CO_2 flood, DOE's CO_2PM, a personal computer program, was used during the initial phase of the design due to its ease of operation and adaptability to waterflooded reservoirs. As shown in Figure 2, the CO_2PM program simulates the CO_2 recovery process for a five spot injection pattern with four corner injectors surrounding a center producer. Reservoir properties data, as shown in Table 1 for Port Neches' Marginulina reservoir, can be entered in the program and results can be obtained within minutes. A dimensionless oil recovery curve versus hydrocarbon pore volumes (HCPVs) of CO_2 injected, and a dimensionless oil yield curve versus HCPVs of CO_2 injected are obtained from the output, and a prediction of the performance of the flood is generated. The program gives an output for a fixed daily rate of CO_2 injection but can, by using a spreadsheet similar to the one shown in Figure 3, be set up to account for the reinjection of produced CO_2. As CO_2 is injected, the oil is recovered at rates which satisfy the dimensionless oil recovery curve, and given the point along the HCPV injected curve, the yield (i.e., BO/MMCF) curve determines the amount of CO_2 being returned with the oil. What may appear to be a very lengthy injection process due to limited daily injection volumes can be shortened dramatically by the reinjection of recycled CO_2 in these high permeability reservoirs.

The CO_2PM program is felt to give reliable results for the five- spot pattern, but what can be done for the asymmetrical pattern seen at Port Neches? The Port Neches Marginulina 235 acre waterflooded fault block is typical of other salt dome fields where wells are often irregularly spaced above the oil-water contact. Some assumptions will have to be made in order for the CO_2PM program to be utilized. The breakthrough of CO_2 to producing wells will occur much sooner than predicted by a 235 acre five spot pattern due to the irregular well spacings, thus affecting the oil response. In order to use CO_2PM for this prediction, the assumption is made that the reservoir will be flooded as though it is three independent five-spot patterns. A 60 acre five-spot pattern will be flooded first, then another 60 acre five-spot, and finally a 115 acre five-spot. CO_2 produced from these first two patterns will be used to flood the final pattern, thus speeding up the process. An initial injection of 4.3 MMCFPD purchased CO_2 will increase to a peak injection of 15 MMCFPD within 4 years. The injection of produced saltwater is also being used to offset fluid withdrawals. This also allows for greater withdrawals from the producing wells (See Figure 4).

COMPOSITIONAL MODEL

Recognizing that CO_2PM has many limitations when attempting to simulate a full field project, a compositional model was developed for the 235 acre project area. Fifty-seven years of primary and secondary waterflood production and pressure history was matched using the limited data available for the project area. The equation-of-state for the original reservoir oil was fine tuned by supplying laboratory constant composition and swelling tests data of a recombined live oil sample to the PVT program[4]. The composition of the original reservoir oil was unknown; however, the bubble point pressure and solution gas/oil ratio could be approximated by field performance data. Methane gas was recombined with the stock tank oil in order to establish the estimated initial gas/oil ratio of 500 SCF/STB and a bubble point pressure of 2685 psia. After further evaluation of the cumulative gas production and oil in place volumes, propane and butane concentrations were added to the oil composition within the PVT program in order to lower the bubble point pressure and solution gas/oil ratio. Reservoir pressure dropped below 100 psia prior to waterflood; therefore, essentially all of the solution gas was produced from the reservoir leaving only 11 SCF/STB of solution gas.

Lack of core data and porosity logs limited reservoir characterization prior to project initiation. After cutting and analyzing a conventional core during a

workover in 1993, the estimated average permeability within the reservoir was increased to 3000 md from 750 md estimated originally. Vertical permeability within the reservoir is seen to be restricted by thin shale streaks that are less than one foot thick. The effect of these shale streaks is difficult to quantify in a reservoir model due to limited knowledge of their lateral extent. Therefore, the reservoir was modeled by a two- layer system with the top layer being 420 md and the bottom layer being 1080 md. Next, the two aquifers affecting the performance of this reservoir were adjusted in strength in the model to obtain the proper pressure distributions and water influx in the reservoir. The compositional model supported the CO_2PM prediction that the CO_2 flood can recover an additional 19% OOIP. It also supported the adjustment of the production profile curve generated by CO_2PM to account for an earlier oil production response.

After comparing current performance to the model's results, the importance of making a proper determination of the reservoir's residual oil saturation to waterflood becomes apparent. It was initially assumed that since only three water injection wells were utilized during the waterflood operation, areas of upswept oil above the residual oil saturation existed in the reservoir. An average oil saturation prior to the CO_2 flood of 30% was calculated for the reservoir, and a residual oil saturation to waterflood of 20% was estimated based upon data obtained from other high permeability sands in the area. However, as open-hole log and core data became available, it was found that the true residual oil saturation to waterflood is 30%. This leaves the reservoir with very little additional mobile oil.

One area of the reservoir has been found to have a higher oil saturation than 30%, and with a change in water injection pattern, has increased oil production from 30 BOPD to 220 BOPD. The higher residual oil saturation will require that higher water percentages be produced until the CO_2-contacted oil reaches the producers.

STREAMTUBE MODEL

A streamtube model has been developed for this project which overcomes many of the limitations of CO_2PM, but can still be run quickly on a personal computer. The model develops streamlines which represent the flowpaths of the injectant and produced fluids and can either be set up as a custom pattern (as shown in Figure 5 for Port Neches' reservoir) or can use standard five-spot, modified seven-spot, inverted nine-spot, regular four-spot, or direct line drive patterns. Utilizing a five-spot pattern as used in CO_2PM, the streamtube model was initialized at different oil saturations to show its effect upon oil recovery and yield (see figures 6 and 7). Upon reviewing this model's prediction of the recoverable CO_2 reserves versus HCPVs of CO_2 injected, some major concerns arise in the project's ability to recover an additional 19% of the OOIP. The oil yield curve also poses major questions about the recycle CO_2 volumes necessary to recover these reserves. As a result of these concerns, a rigorous investigation into the prediction of CO_2 flood performance using CO_2PM, the streamtube model, and compositional models has been completed.

FIVE-SPOT COMPOSITIONAL MODEL

A 29 X 29 X 3, 40-acre five-spot compositional model was developed to determine the accuracies which one can expect from the PC-based simulation programs such as CO_2PM and the streamtube model. An equation-of-state for the current reservoir oil (as opposed to the original reservoir oil) was determined by running the PVT program with laboratory constant composition data input. This was accomplished by splitting the C7+ fraction into four pseudocomponents. In order to have consistent parameters, the oil/water relative permeability curve used in CO_2PM and the streamtube model is used and absolute permeabilities are set equal to those used in CO_2PM of 6404 md, 1991 md, and 605 md (Dykstra Parsons[5] coefficient of 0.7) for layers one, two and three, respectively. Each sand layer is 10 feet thick. An oil viscosity of 3.3 cp is obtained from laboratory data at 3400 psia. CO_2PM and the streamtube model were run with this same viscosity. (It may be pointed out that without the AVIS viscosity correction in the equation-of-state, the oil viscosity calculated by the compositional model is 1.4 cp.)

These properties closely represent a reservoir oil with a solution gas/oil ratio of 11 SCF/STB. The actual stock tank oil composition differs from the oil composition predicted by the compositional model used to obtain the production history match, with the current reservoir oil having fewer lighter components (See Table 3). This lack of lighter components results in a poorer oil recovery than seen previously and may contribute to some of the uncertainties associated

with our previous history match, particularly when the original oil composition was not known.

RESULTS

A comparison of the dimensionless curves for the three models is shown in Figures 8 and 9. It is seen that the streamtube and compositional models provide similar results up to 2.0 HCPVs of CO_2 injection, and then deviate from that point. CO_2PM has a much slower production response than the other models, but has a higher ultimate recovery. The yield curves show quite substantial deviation, with the compositional model showing extremely low yields after approximately 1.3 HCPVs of CO_2 injection. To explain this phenomenon, a closer look at the compositional model's results reveal some important observations.

The CO_2PM and streamtube programs both use a Dykstra Parsons coefficient to represent heterogeneity within the reservoir. For the three layer model run, the highest permeability of 6400 md is automatically placed as the top layer of the reservoir and the lowest, i.e., 605 md, is placed on the bottom. The density segregation of the CO_2 in the high permeability upper layer results in poor vertical sweep efficiency of the sand (See Figure 10). A model using three layers of equal permeability of 3000 md gives very similar results to the coarsening upward sequence case. The five-spot compositional model allows for these layers to be rearranged.

If the lower permeability layer of 605 md is placed on top of the 1991 md and 6404 md second and third layer intervals, respectively, still maintaining a Dykstra Parsons coefficient of 0.7, the projected oil recovery from the model is greatly improved (See Figures 11 and 12). This fining upward sequence is typical of fluvial-dominated deltaic reservoirs and may contribute to improved recoveries through application of the CO_2 flooding process at Port Neches.

To extend these concepts one step further, all models were run with varied permeability, initial oil saturation, vertical to horizontal permeability ratios (Kv/Kh), and reduced permeability-feet (Kh) (See Figures 13 through 16). In high permeability sands (i.e., greater than 250 md), the recoveries were mostly dependent upon oil saturation at the start of the CO_2 flood, but as seen by the fining upward sequence example discussed, the recovery is also very sensitive to permeability profile. This wide range in recovering efficiencies resulting from changes in oil composition, vertical layering, and HCPVs of CO_2 injected, supports the use of multi-disciplinary teams of engineers and geoscientists to improve the prediction phase of these projects. Actual field implementation will determine the accuracy of these predictions.

CONCLUSIONS

1. The Port Neches CO_2 miscible flood will attempt to lower the oil saturation from 30% residual to an average of 17% in a fluvial-dominated deltaic reservoir. As a result, an additional 2 MMBO, or 19% OOIP, will be recovered.

2. A streamtube model that was developed as part of the technology transfer for this project, is capable of accurately predicting the recoveries associated with waterflood and CO_2 flood processes. This model is expected to benefit the design of CO_2 projects in various types of reservoirs and will be released to the oil industry during 1994 through SPE/DOE.

3. A five-spot compositional model utilizing the equation-of-state of the stock tank oil from Port Neches was used to determine the accuracy of the CO_2PM and streamtube models. The streamtube model was shown to be an effective screening tool for applying CO_2 floods.

4. Results from the streamtube and five-spot compositional models indicate that the risk of accurately predicting the outcome of CO_2 floods is highly dependent upon the vertical sweep efficiency obtained within the reservoir.

5. The results obtained by using an equation-of-state of the currently existing reservoir oil, as opposed to the original reservoir oil, may improve the prediction phase of compositional modeling. By initializing the model with this improved equation-of-state, an average oil saturation across the oil zone equal to 30%, and the best geological description available, a more realistic forecast may occur.

ACKNOWLEDGEMENTS

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TABLE 1
CO2PM INPUT

PARAMETER	VALUE	PARAMETER	VALUE
Depth	5900 feet	N_{oil}	2
Porosity	30%	N_{wat}	2
Permeability	Variable	K_{ro} @ S_{wi}	1.0
API Gravity	34.6°	K_{rw} @ S_{or}	0.116
Area	40 acres	S_{wc}	0.20
Height	30 feet	S_{orw}	0.30
No. Layers	3	B_o	1.05
Reservoir Pressure	3400 psi	μ_o	3.28
Temperature	165° F	R_s	11
K_V/K_H	0.85	SG (gas)	0.6
Oil Cut	0.001	Salinity	100,000 ppm
Injection Rate	2150 BFPD	V	0.7
WAG Ratio	0.05	HCPV	5.0

TABLE 2
STREAMTUBE MODEL INPUT

PARAMETER	VALUE	PARAMETER	VALUE
Dykstra Parsons	0.7	K_{wro}	0.116
Temperature	165°F	S_{wir}	0.20
Reservoir Pressure	3400 psi	S_{orw}	0.30
MMP	3310 psi	N_{wat}	2.0
μ_o	3.28 cp	K_{rocw}	1.0
B_o	1.05	S_{wc}	0.20
Solution GOR	11.0	N_{oil}	2.0
Oil Gravity	34.6° API	K_{rgcw}	0.477
Gas Specific Gravity	0.6	S_{gr}	0.30
μ_w	0.47	N_{gas}	2.0
Salinity	100,000 ppm	S_{org}	0.30
Layers	3	S_{orm}	0.001
Pre-Set Pattern	5-Spot	S_{oi}	0.3001

TABLE 3 - PVT COMPOSITION OF CURRENT RESERVOIR OIL

PVT COMPOSITION

COMPONENT	PC	TC	MW	OMEGA	OMEGB	ZCRIT	CRITZ	PCHOR	AC	REFD	REFT	TBOIL
1 PC1	550.7	765.6	58.12	0.42748023	0.08664035	0.2742	0.2742	189.900	0.1930	0.58440	60.0	31.1
2 CO2	1070.0	547.8	44.01	0.44910847	0.09215464	0.2749	0.2527	79.700	0.2250	0.77700	68.0	-109.2
3 PC2	453.8	895.5	82.27	0.42445979	0.08657156	0.2657	0.2666	260.028	0.2835	0.61480	139.4	139.4
4 F7	379.4	1078.5	124.49	0.30164148	0.09831126	0.2614	0.2614	401.739	0.3576	0.75344	60.0	285.0
5 F8	265.3	1247.6	191.13	0.49320023	0.08208457	0.2418	0.2418	593.821	0.5107	0.80675	60.0	453.5
6 F9	182.9	1440.8	293.24	0.56240752	0.10033184	0.2208	0.2208	880.971	0.7269	0.86339	60.0	660.6
7 F10	98.3	1694.1	469.21	0.48377806	0.07069124	0.1609	0.1609	1529.928	0.9862	0.93121	60.0	939.7

VISD .0087398 .0171533 .0076849 .0068290 .0056734 .0046768 .032690

AVIS -2.03281 1.41452 .441014 -.450068 .078543

	PC1	CO2	PC2	F7	F8	F9
BIN	0.106000	0.018813	-0.096436	-0.096436	-0.096436	-0.096436
	0.106000	0.066277	0.066277	0.066277	0.066277	
	-0.003985	-0.003985	-0.003985	-0.003985		
	0.000000	0.000000	0.000000			
	0.000000	0.000000				
	0.000000					

OIL COMPOSITION OF CURRENT RESERVOIR OIL

	PC1	CO2	PC2	F7	F8	F9	F10
Z	.00040	.00000	.00360	.18062	.38380	.29739	.13420

OIL COMPOSITION OF CURRENT RESERVOIR OIL BY HISTORY MATCH

	PC1	CO2	PC2	F7	F8	F9
Z	.04580	.00000	.05300	.33690	.41360	.15070

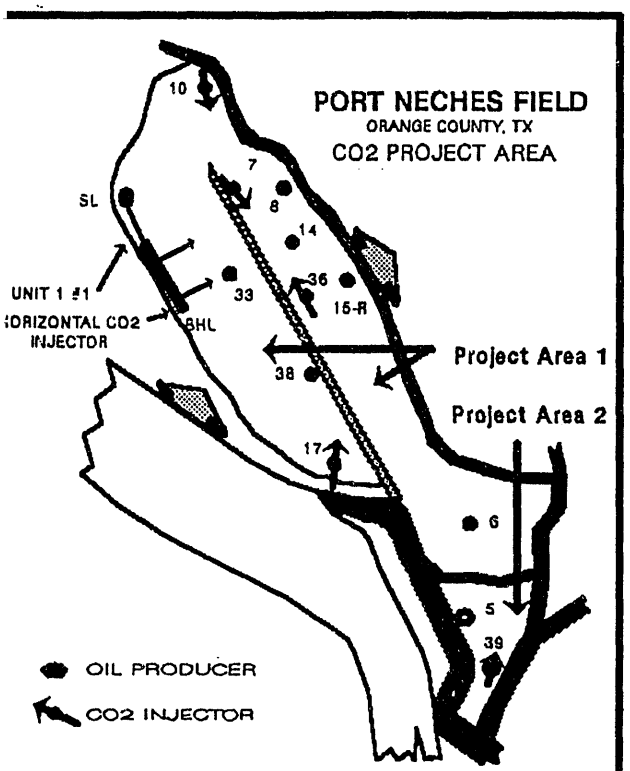

Figure 1 - Field Injection Pattern

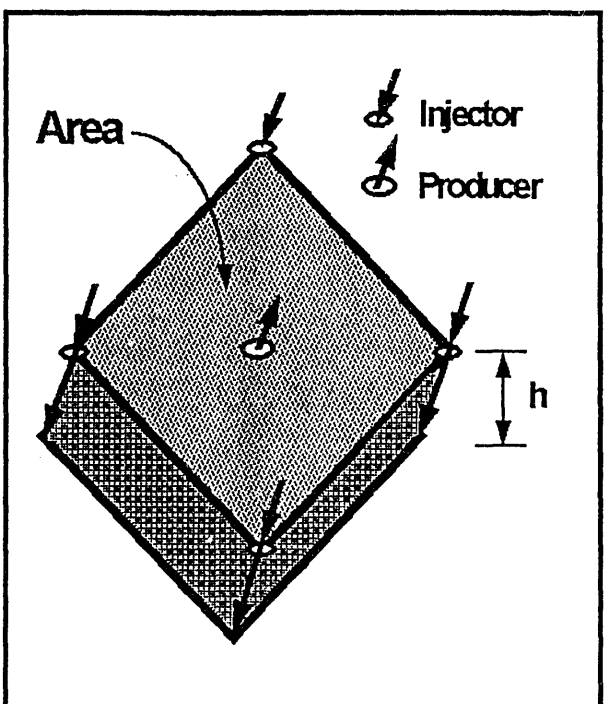

Figure 2 - Five Spot Injection Pattern

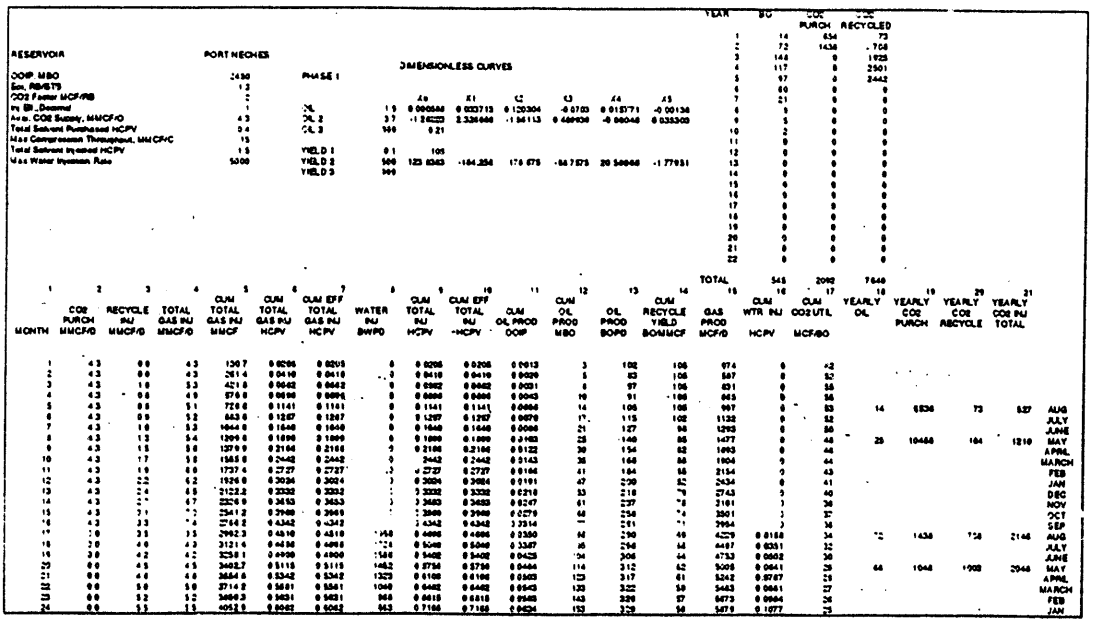

Figure 3 - CO_2 Recycle Volume Determination Spreadsheet

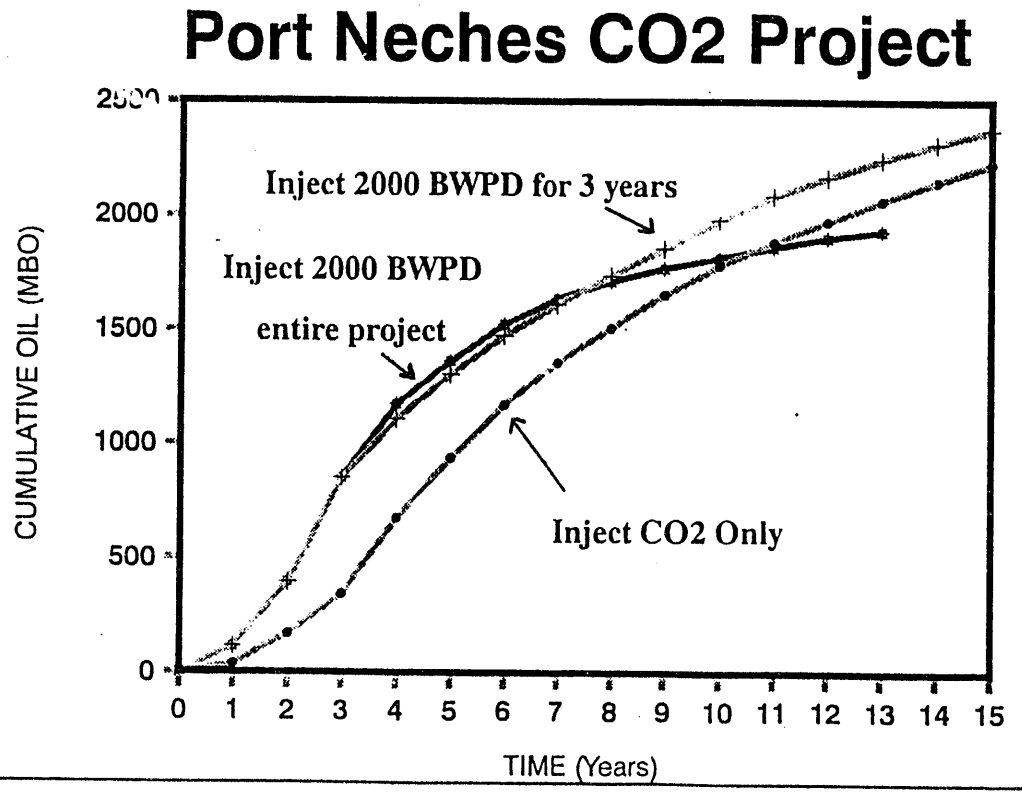

Figure 4 -Advantages of Water Injection

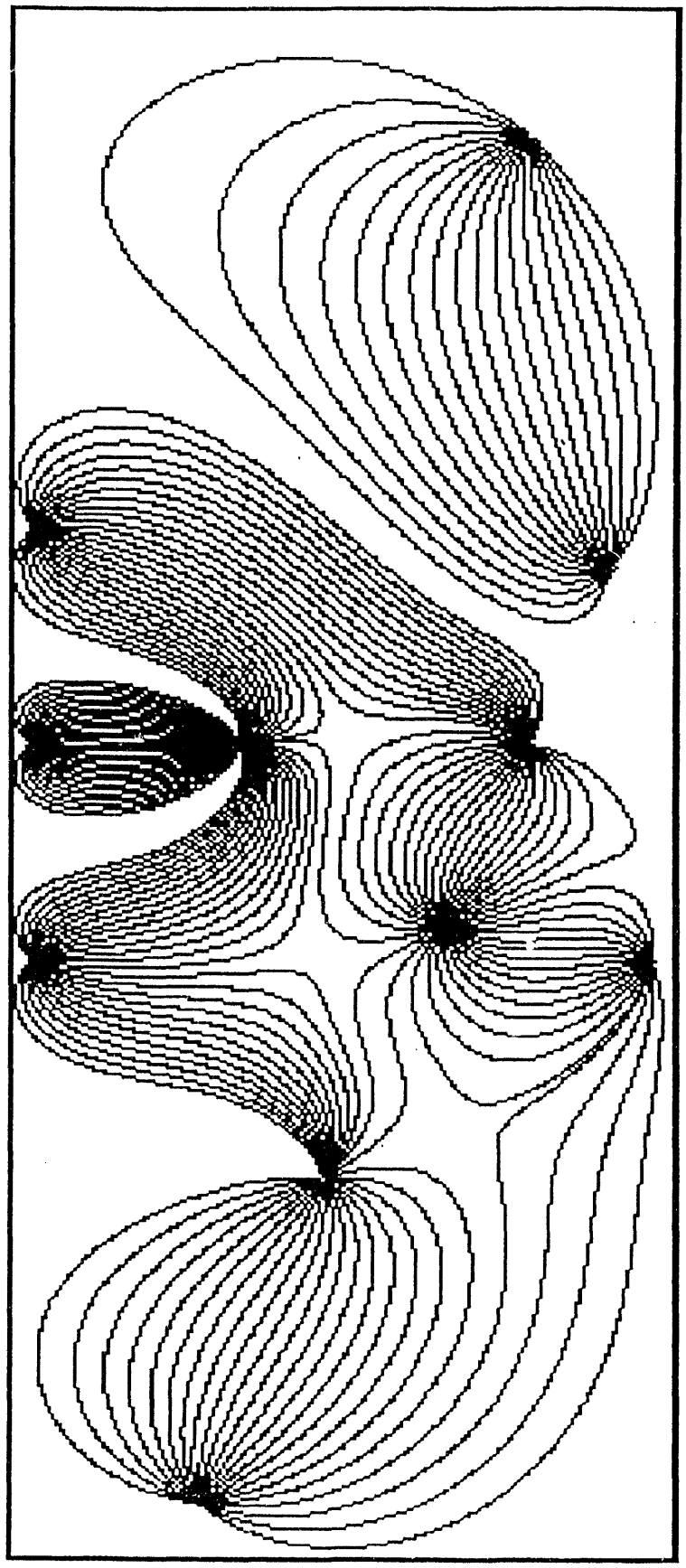

FIGURE 5

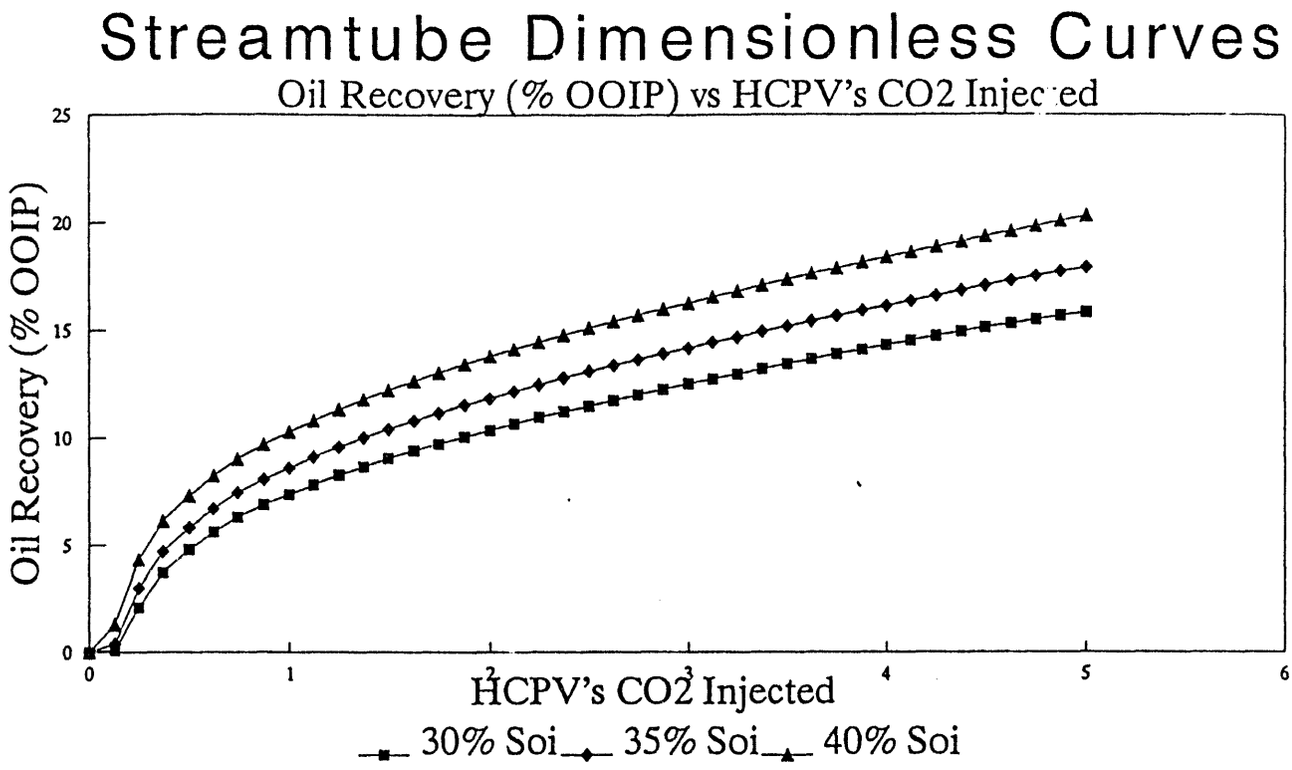

Figure 6. Streamtube Dimensionless Oil Recovery Curve versus HCPV's CO2 injected at varying initial oil saturation.

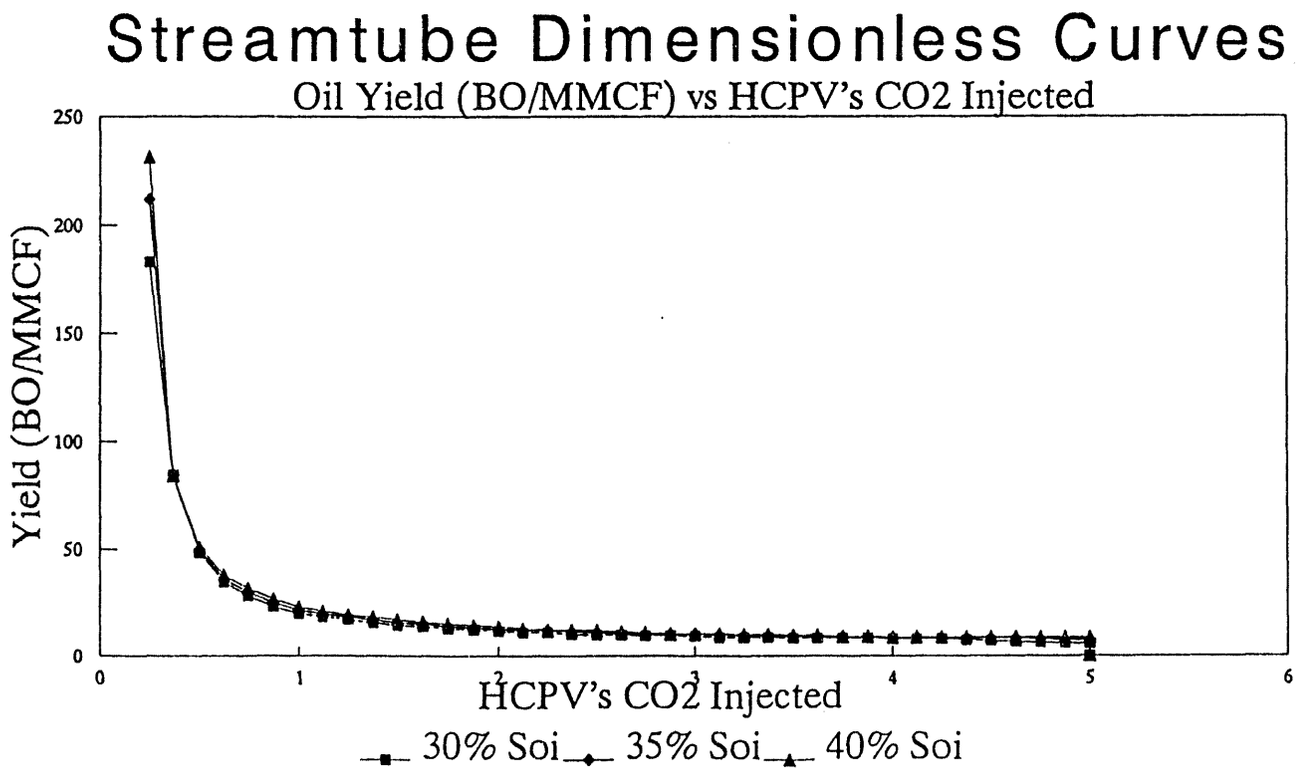

Figure 7. Streamtube Oil Yield Curve versus HCPV's CO2 injected at varying initial oil saturation.

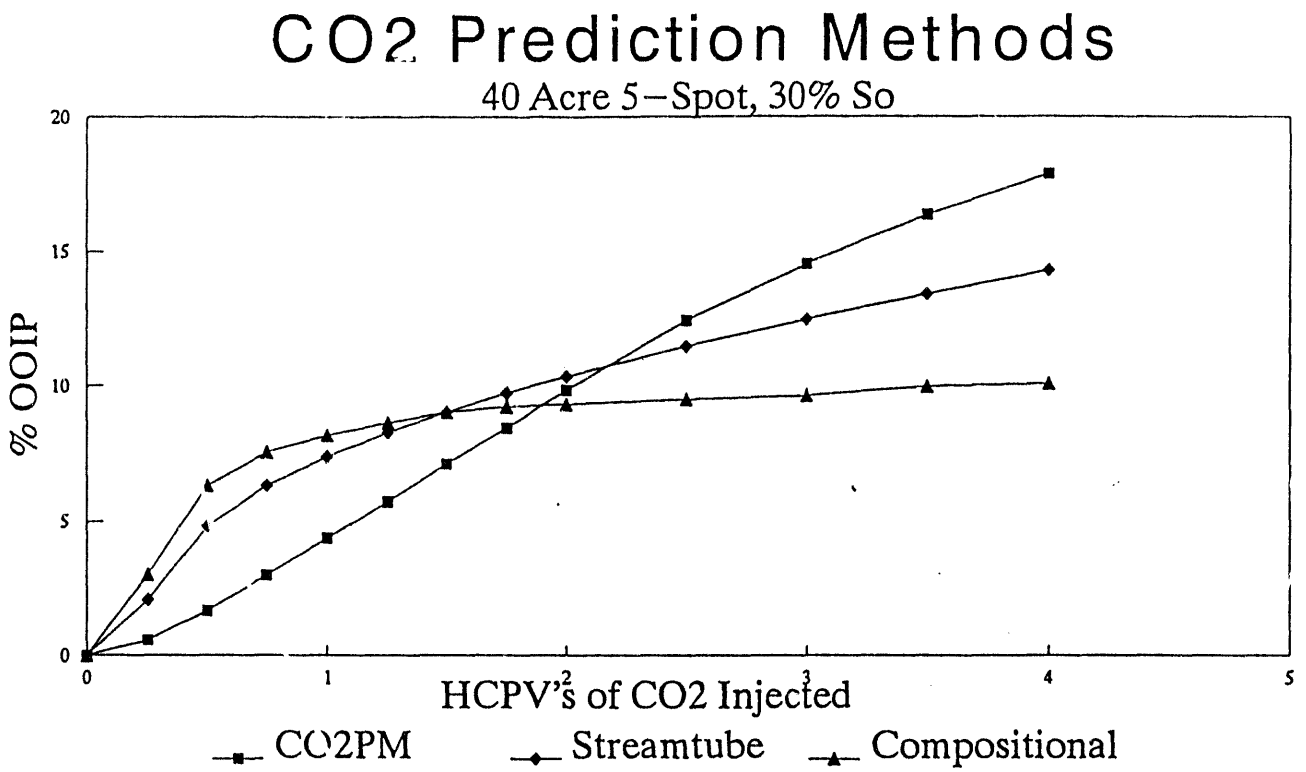

Figure 8. Comparison of Dimensionless Oil Recovery Curves versus HCPV's CO2 injected for three different models.

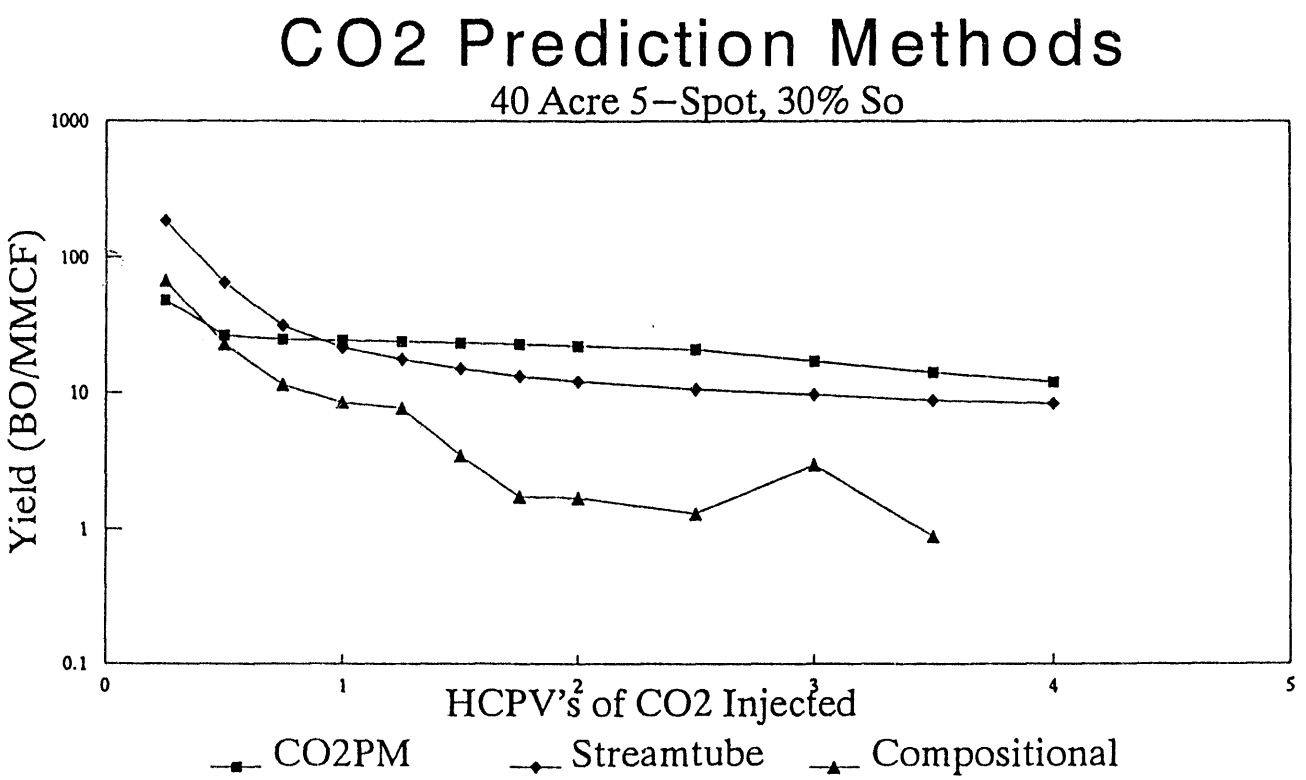

Figure 9. Comparison of Oil Yield Curves versus HCPV's CO2 injected for three different models.

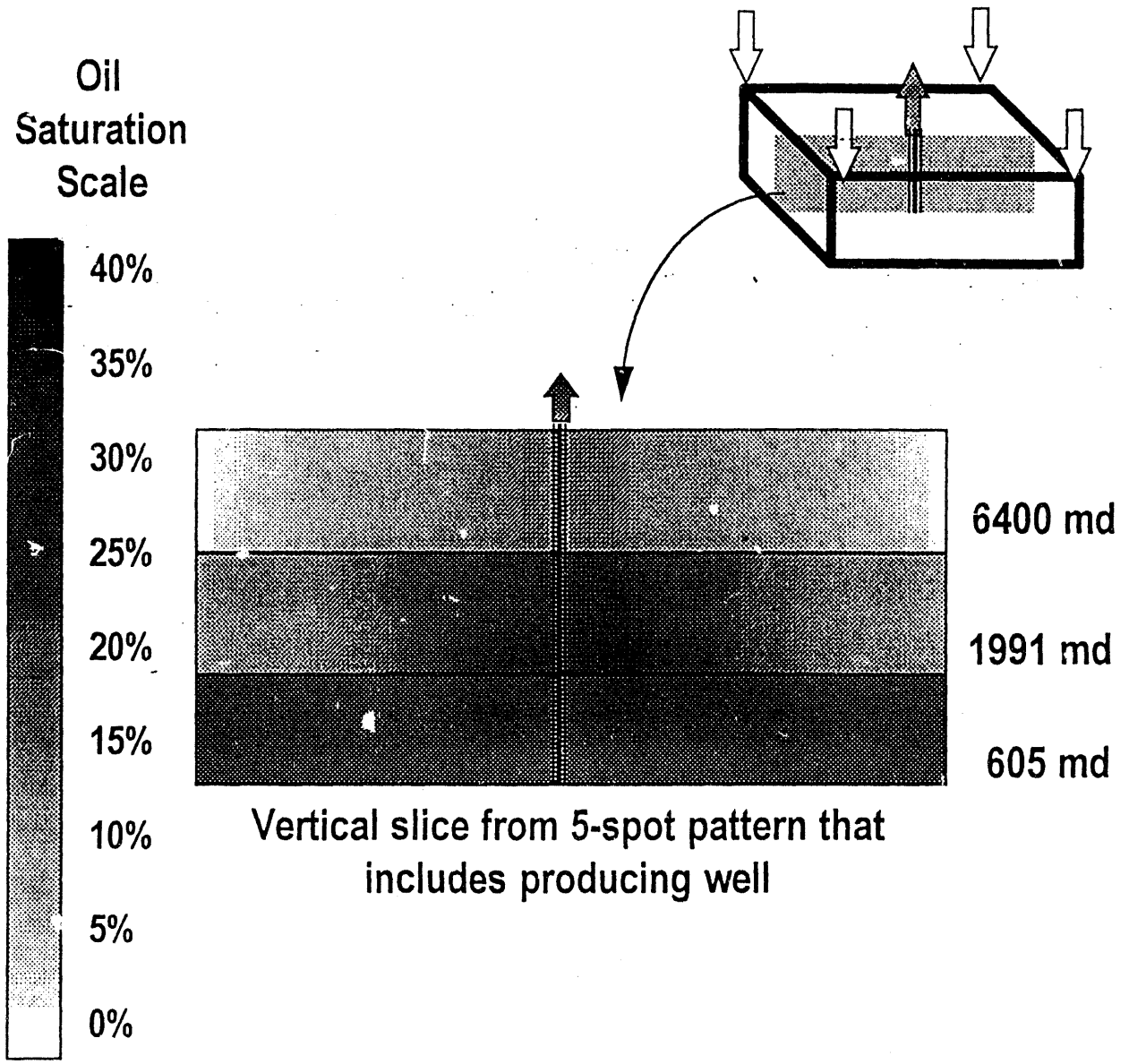

Figure 10 - Remaining Oil Saturation After CO_2 Injection

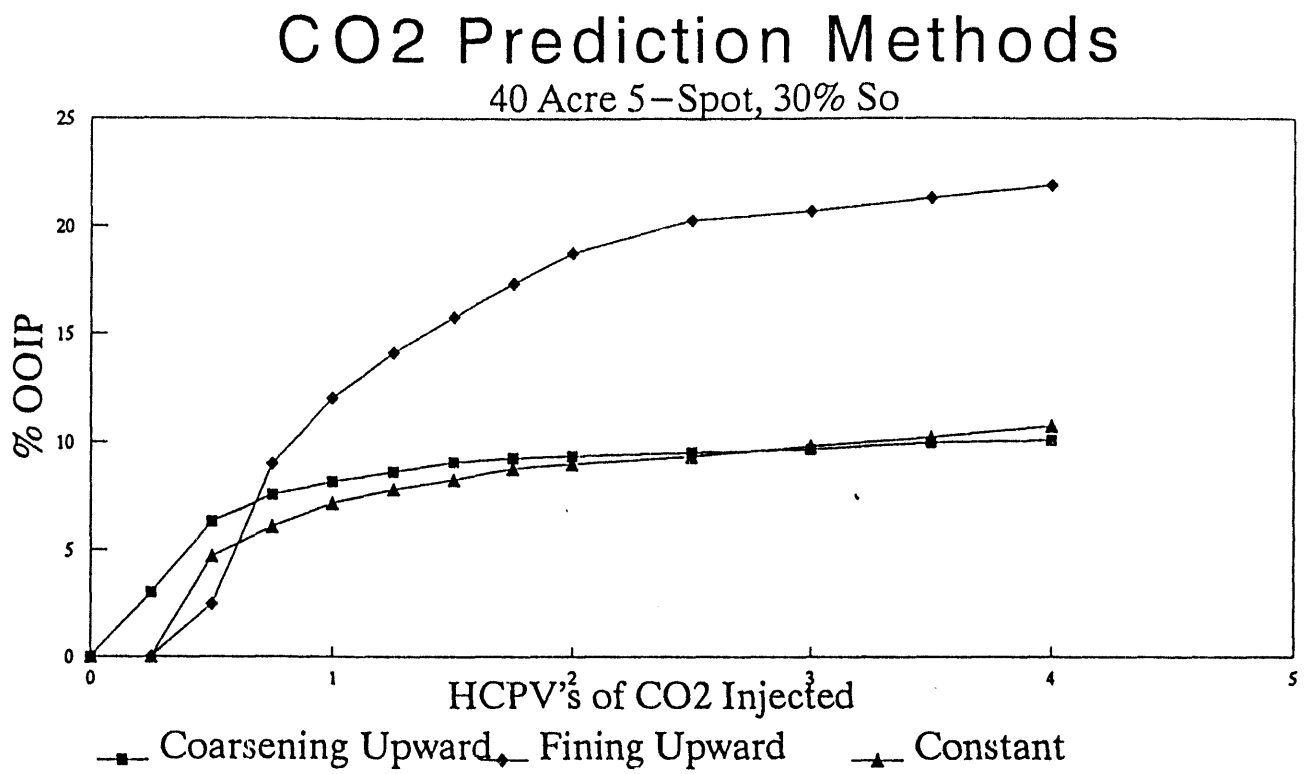

Figure 11. Oil Recovery versus HCPV's CO2 Injection for Five-spot Compositional model with permeability of layers varied.

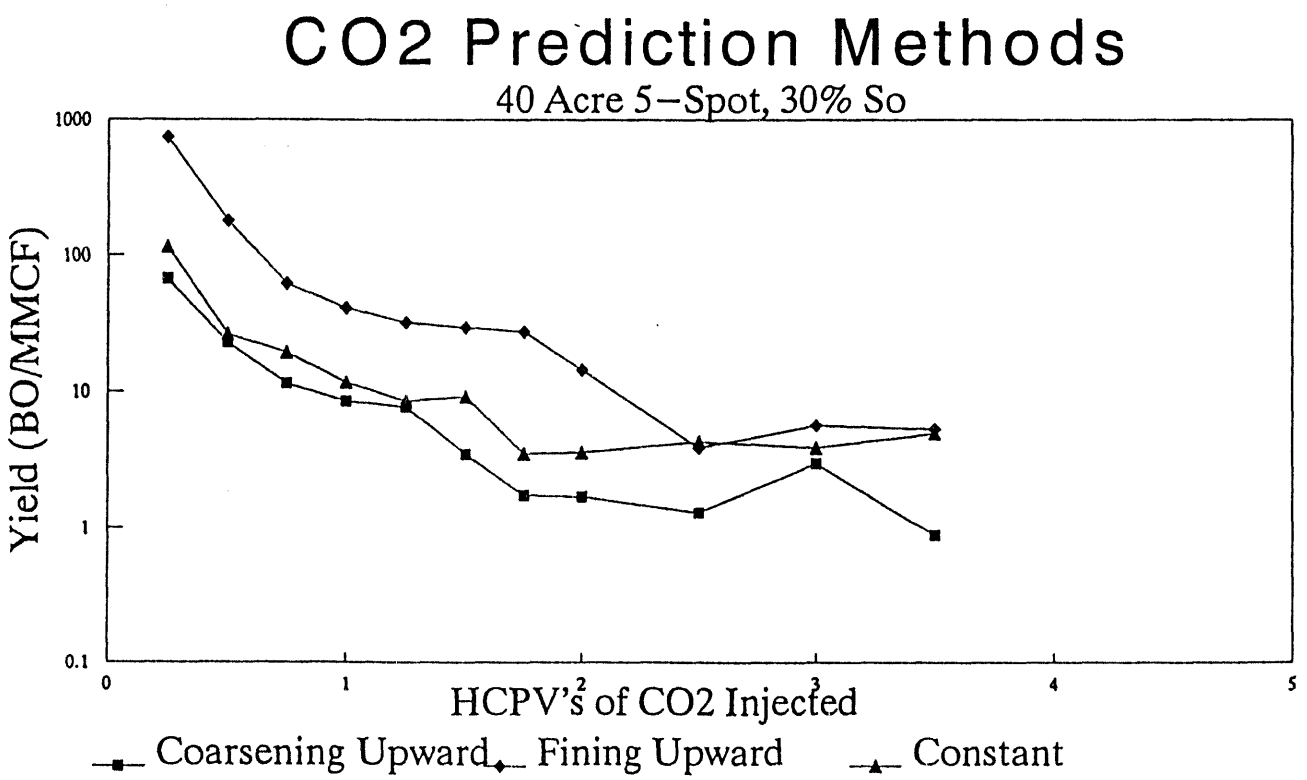

Figure 12. Oil Yield versus HCPV's CO2 Injection for Five-spot Compositional model with permeability of layers varied.

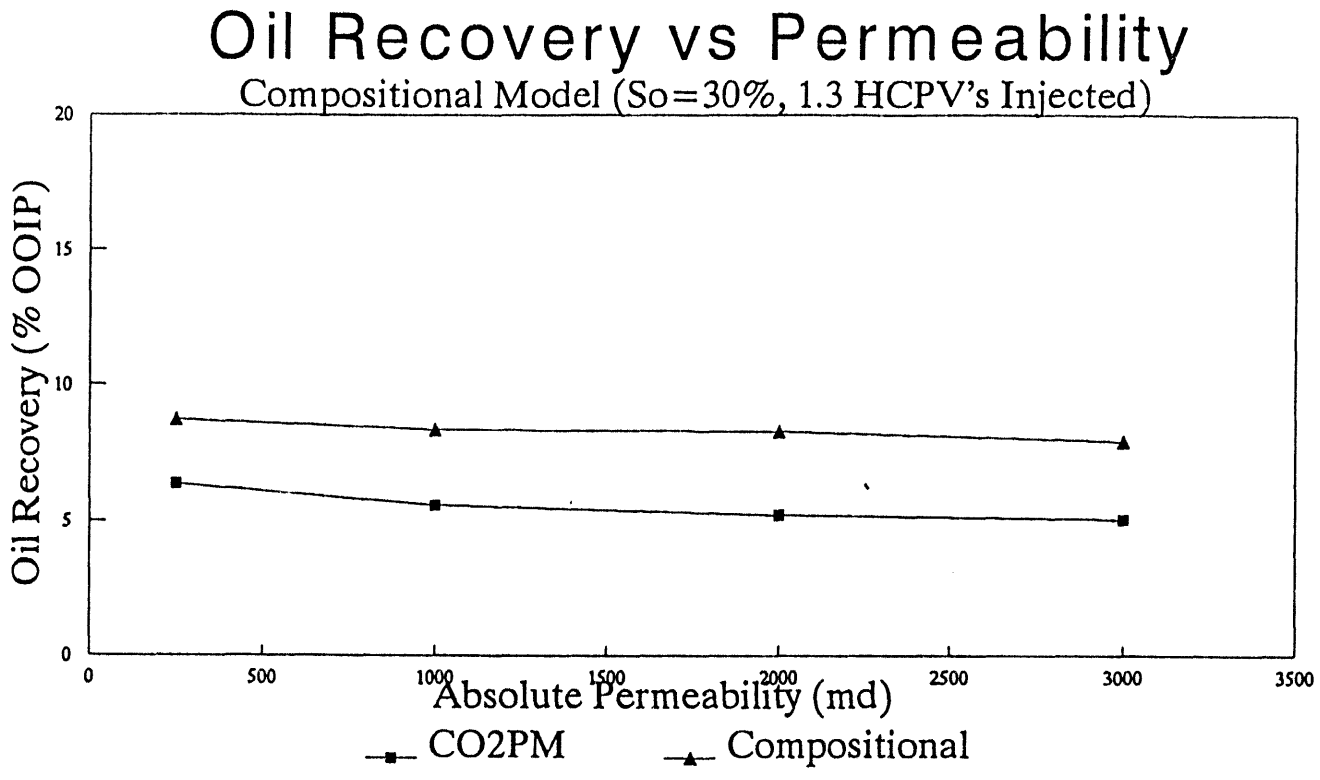

Figure 13. Oil Recovery after 1.3 HCPV's CO2 Injection versus Absolute permeability, as determined by Compositional Five-spot and CO2PM models.

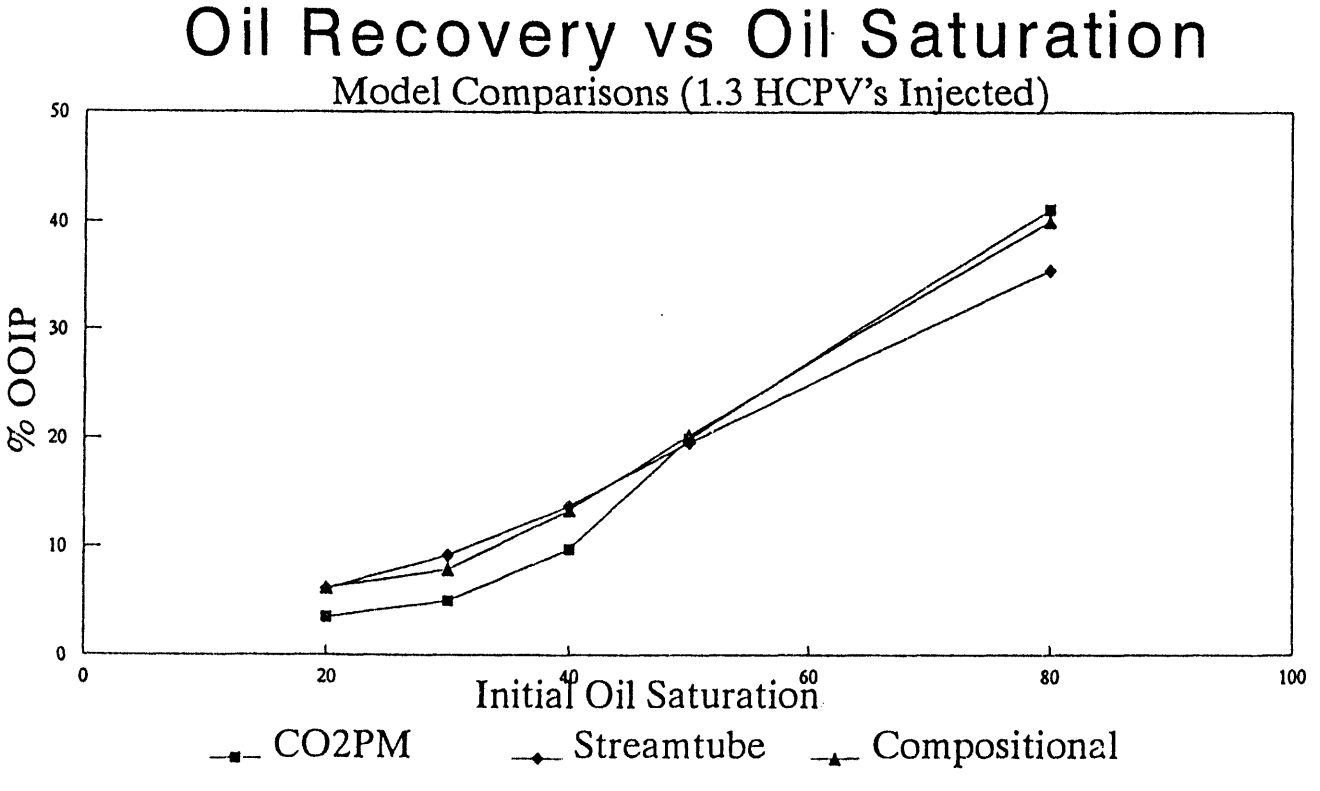

Figure 14. Oil Recovery after 1.3 HCPV's CO2 Injection versus Initial Oil Saturation, as determined by three models.

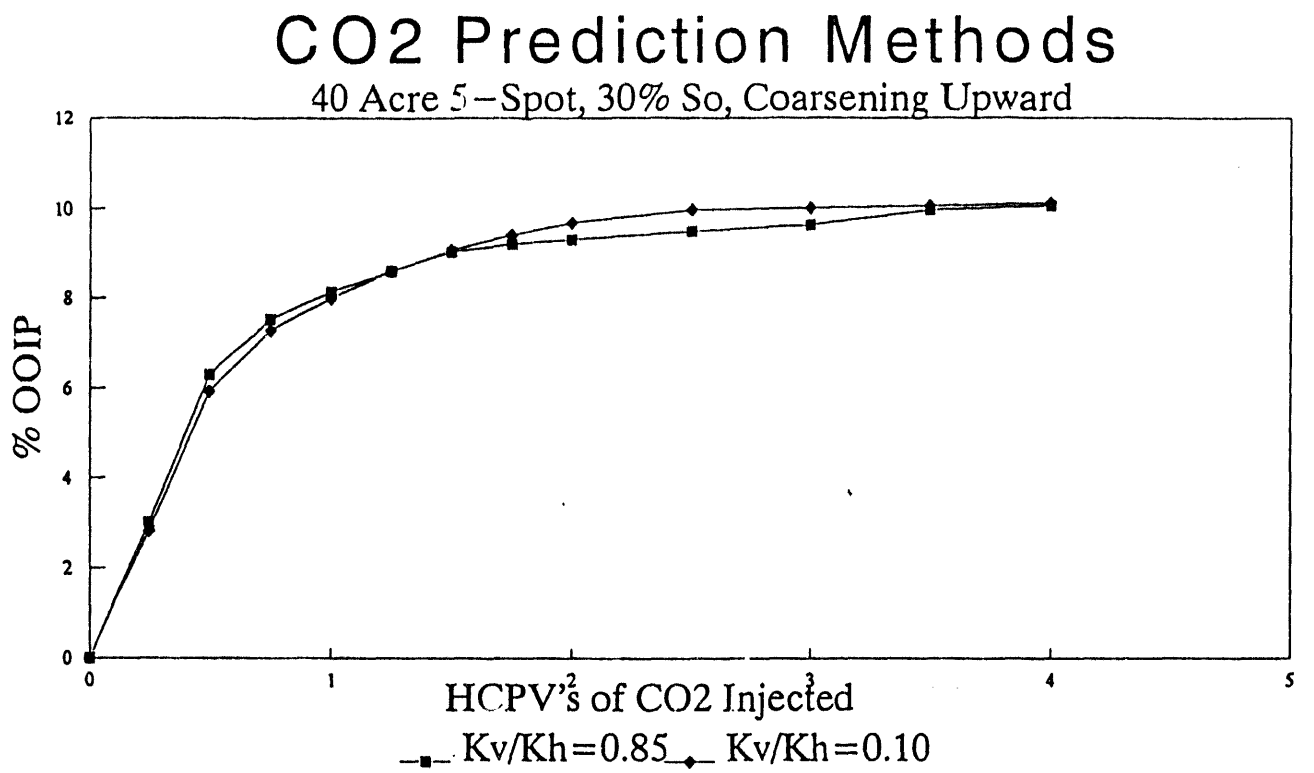

Figure 15. Oil Recovery versus HCPV's CO2 Injection for Five-spot Compositional model with vertical to horizontal permeability varied.

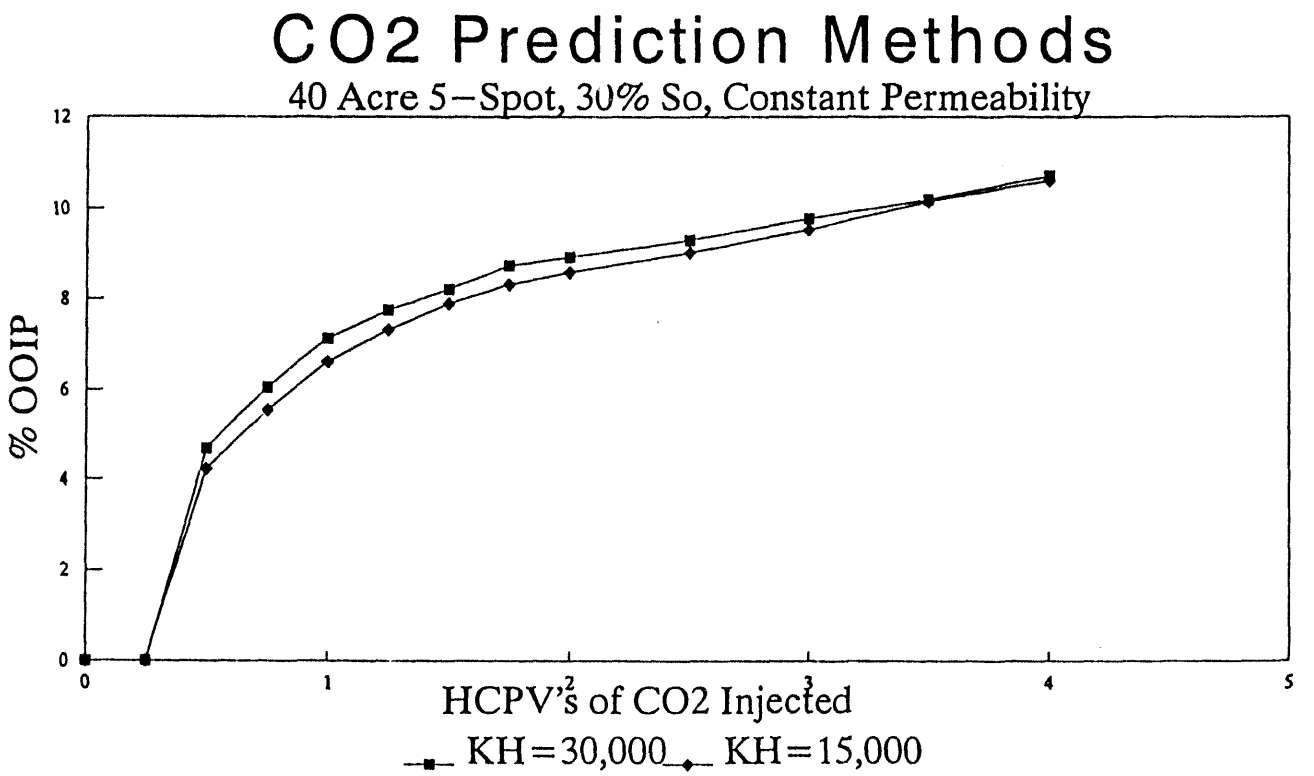

Figure 16. Oil Recovery versus HCPV's CO2 Injection for Five-spot Compositional model with varying KH values.

Appendix B

ABSTRACT

)2-Prophet, a water and gas flood prediction software ›duct, has been developed by Texaco with support of the S. Department of Energy (DOE). This paper describes ; model and presents case comparisons with physical ›dels and commercial reservoir simulators.

)2-Prophet has been shown to be a good tool for screen- ; and reservoir management and is being released to the iustry complete with a detailed user manual. Ease of use s emphasized in the development of the user interface.)2-Prophet runs on PC compatible computers and fol- ving are some of its features:

- A front end for easy reservoir parameter input.
- Several predefined patterns to simplify use.
- The ability to design patterns to fit most situations
- Fast computation.
- Multiple flood regimes so water, gas, and miscible floods can be modeled.
- Output in surface units and dimensionless formats.
- Output designed for importing into a spreadsheet

'2-Prophet computes streamlines between injection and duction wells to form stream tubes. It then makes flow nputations along the stream tubes. The mixing ameter approach, proposed by Todd and Longstaff[1], is d for simulation of the miscible process. CO2-Prophet s the Dykstra-Parsons[2] coefficient to distribute the initial injection into a maximum of ten layers, and then fractional flow calculations determine the flows and fluid saturations along the stream tubes. Program inputs are pattern description, relative permeability curves, initial saturations, injection rates, and reservoir-to-surface conversions. A new case can be set up and run in a few minutes making this program ideal for the screening of EOR projects and pattern comparisons.

The hardware requirements to run CO2-Prophet are an Intel® 386 based PC or better with at least 4 megabytes of RAM and 4 megabytes of disk space free. A math coprocessor is required for 386 or 486SX systems.

INTRODUCTION

CO2-Prophet was developed with partial support of the DOE as part of the Class I cost share program "Post Waterflood, CO_2 Flood in a Light Oil, Fluvial Dominated Deltaic Reservoir." It was written as an alternative to the DOE distributed CO_2 miscible predictive model (CO2PM). CO2PM has limitations that interfere with the accurate prediction of CO_2 flood response when the field realities do not match the assumptions made in CO2PM. The most limiting restrictions are the five spot well configuration and not being able to handle alternate injection schemes such as hybrid WAG and tapered WAG. It has also been recognized that the predictions made by CO2PM are generally optimistic in terms of oil rate and recovery.

CO2-Prophet was written to be a flexible tool that does not suffer from the limitations of CO2PM and, at the same time, is easy to use. CO2-Prophet has been extensively

'erences and illustrations at end of paper.

:sted and has been used for prediction of waterflood and :O_2 flood performance and for screening purposes. Also, it as been used for rate prediction for economic analysis of lanned CO_2 floods. CO2-Prophet is also a good tool for ıe prediction and analysis of waterfloods It produces :sults very close to those of much more sophisticated :servoir simulators when the reservoir description is fairly ncomplicated.

O2-Prophet can be used with virtually any flooding pat-rn. It comes with files generated for common patterns ıch as the five spot or inverted nine spot (Table 1). It is so possible to generate the stream tube files for any pat-rn that you wish (Figure 1). Patterns are input by defining :ttern boundaries and locating the injectors and producers ith X and Y coordinates and specifying well rates. Up to n injectors and ten producing wells can be input.

O2-Prophet can simulate many different injection :hemes including waterfloods, CO_2 floods, WAG (with fferent ratios), or any combination of these. Individual tes can be specified for each injection well for each of ur injection periods.

utput is in three formats: dimensionless (hydrocarbon ıre volumes), surface units readable by people, and rface units suitable for importing into a spreadsheet. me between surface unit report times can be annual, annual, quarterly, or monthly. Graphical output was not corporated so that changes in hardware would have inimal effect on the operation of the program.

verall operation of CO2-Prophet is easy. A front end with op down menus and entry fields is supplied to generate ɔut files and control the main program. Default values ɔ included to get the program running for the novice user. ror and consistency checks are done on entry fields. The ɔut file can also be manipulated directly by the perienced user to gain flexibility of operation.

DESCRIPTION OF THE MODEL

)2-Prophet creates a stream tube model of a reservoir. 'eam lines are constructed using potentials based on the ɔr-specified injection and production rates and well :ations in an areally homogenous field. Stream tubes are med from these stream lines, and the tubes are divided o sections for finite difference calculations. The lengths d areas of these sections are written to files to be used for ure runs. The area of the reservoir is mapped into these ɔam tubes to make all the pore volume of the pattern :essible to flow. Areal heterogeneity is modeled by the ference in the lengths and areas of the stream tubes as :n in Figure 1.

e reservoir is further divided into a user specified nber of equal thickness layers to model three ıensional flow. The Dykstra-Parsons coefficient is used calculate the comparative permeabilities of the layers. reservoir heterogeneity in CO2-Prophet is introduced through the Dykstra-Parsons coefficient. The total thickness of these layers can be calculated from a specified OOIP or input by the user in which case CO2-Prophet calculates OOIP. From one to ten layers can be specified, and five layers seem to work well for most situations. Cross flow between layers is not allowed, and gravity effects are not included.

Overall layer resistances are used to determine the fraction of the injection that will be routed into each layer. Figure 2 illustrates the distribution of initial relative injectivity with a Dykstra-Parsons coefficient of 0.7. Injection into each layer is determined by the product of the formation resistance and the mobility resistance as determined by relative permeabilities and fluid viscosities. The relative injections change as saturations change during the flood. Miscible fluids are handled by varying the viscosity using the Todd and Longstaff mixing parameter. No empirical correlations are used for areal or vertical sweep efficiency.

In typical mixing parameter models, the miscible phase relative permeability is set equal to the oil relative permeability. CO2-Prophet does not have this limitation. The miscible phase relative permeability can be handled in three different ways.

The first option makes the miscible phase relative permeability, k_{rm}, a saturation weighted average of the solvent and oil relative permeabilities.

$$k_{rm} = \frac{S_o - S_{orm}}{1 - S_w - S_{orm}} k_{row} + \frac{S_g}{1 - S_w - S_{orm}} k_{rs} \quad \text{.....(1)}$$

This method directly incorporates the relative permeability of the solvent and is similar to the Solvent Relative Permeability (SRP) method presented by Chopra, Stein, and Dismuke [3]. The solvent relative permeability can be defined as the gas relative permeability, but it does not have to be.

The second option makes the miscible phase relative permeability the average of the gas and oil relative permeabilities.

$$k_{rm} = 0.5\,(k_{row} + k_{rg}) \quad \text{.....(2)}$$

The third option, in which the miscible phase relative permeability is set equal to that of the oil, is the standard formulation which is used in mixing parameter models.

$$k_{rm} = k_{row} \quad \text{.....(3)}$$

The solvent and oil are tracked separately even though they are miscible. This is done by dividing the miscible phase relative permeability and assigning to the solvent and oil the correct fractions. The correct fractions are based on saturation.

Inder miscible conditions, the gas relative permeability is:

$$k_{rg} = \frac{S_g}{1 - S_w - S_{orm}} k_{rm} \quad \text{.....(4)}$$

nd the oil relative permeability is:

$$k_{ro} = \frac{S_o - S_{orm}}{1 - S_w - S_{orm}} k_{rm} \quad \text{.....(5)}$$

ı some formulations, the miscible residual is left out of ıe denominator. However, when this is done, the non-queous phase permeability is not completely distributed etween the CO_2 and the oil.

imple material balances are used throughout. There are no rms in the flow equations for compressibility; so, the olume injected is the volume produced. Also, perme-ility is not input into the model. The average rmeability of the formation is expressed in the rate of jection. Conversions between surface units to reservoir its are done for both injection and production.

VERIFICATION

ıe output of CO2-Prophet has been compared with the iggins-Leighton[4] waterflood model as presented by 'illhite[5] and two commercial compositional simulators for iscible displacement, COMP III from Scientific oftware-Intercomp, Inc. and VIP-EXEC(COMP) from 'estern Atlas Software.

ıe Higgins-Leighton displacement data was converted to e same dimensionless basis as CO2-Prophet and mpared directly. The Higgins-Leighton stream tube odel was designed to model fluid flow consistent with ıckley-Leverett[6] displacement. Figure 3 shows that the reement between the Higgins-Leighton model and 02-Prophet is quite good. This result is from a five spot ttern as are the rest of the comparisons.

ıe remaining comparisons were performed using data m a Permian Basin CO_2 flood prospect (Appendix). A 'e spot pattern was modeled using five layers with no rtical transmissibility. Each of the layers was mogenous. Three different flooding scenarios were used; l Water Alternating Gas (WAG) tertiary injection, ntinuous CO_2 tertiary injection, and continuous CO_2 condary injection. The saturation weighted method was ed to calculate the miscible phase relative permeability CO2-Prophet. The gas to oil endpoint relative perme-ility ratio was 0.34. A ratio other than 1.0 makes it a ficult test for a mixing parameter model. The miscible idual oil saturation was set to zero. No attempt was ıde to match the results of CO2-Prophet to the npositional simulators by adjusting input parameters. e same input data were used for all three simulators, and output results were compared. A nine-point finite dif-ence formulation was used for the compositional ıulators to reduce grid orientation effects.

Figure 4 shows the results of the waterflood comparison between CO2-Prophet, COMP III and VIP-EXEC(COMP). The outputs of the three simulators are nearly identical.

A 1:1 WAG injection after waterflood was then simulated. The WAG was modeled as simultaneous injection rather than as discreet alternating slugs. Figures 5 and 6 show generally good agreement between CO2-Prophet and the other simulators. The agreement is especially good through the period of WAG injection, which lasts until 0.67 HCPV has been injected. The oil recovery prediction flattens more for the compositional simulators than it does for CO2-Prophet during the chase water drive which follows the WAG injection. The peak oil rate of CO2-Prophet is somewhat lower, and the production declines more slowly for an overall recovery of about 3% OOIP more. Even with the higher total recovery CO2-Prophet is probably more conservative than the two other simulators when economics are taken into consideration since the oil rate is lower until approximately 0.5 HCPV injection.

Figure 7 shows the comparison of CO2-Prophet and COMP3 with a continuous tertiary CO_2 flood (CO_2 injection after a waterflood). Both rates and total recovery are slightly lower for CO2-Prophet though the final difference is only about 2% OOIP. CO_2 is injected for 0.31 HCPV followed by chase water.

Figure 8 shows the results of the last comparison, a secondary CO_2 flood (CO_2 is injected continuously). The initial water saturation is at the connate level, and the rest of the pore space initially contains oil. CO2-Prophet predicts a slightly lower recovery, but the difference is not very large.

CO2-Prophet predicts oil recoveries very similar to those of compositional simulators for reasonably simple reservoir descriptions. Such descriptions are ones with no areal heterogeneity and no vertical transmissibility. The results are especially good for WAG processes. Consequently, CO2-Prophet is a very good tool for screening and even for forecasting when a great deal of reservoir description is not available.

Gas Relative Permeability

CO2-Prophet has a feature which makes it more versatile than other mixing parameter models. The saturation weighted formulation for the miscible phase relative permeability makes it possible for CO2-Prophet to more closely match the results of compositional simulators when the gas and oil relative permeability curves are very different.

Compositional simulators predict different oil recoveries for different gas relative permeability curves. However, the traditional mixing parameter models do not do this because they do not use the gas relative permeability curve in their formulation of the miscible phase relative permeability.

'able 2 shows how the predicted oil recovery is changed /hen the gas relative permeability curve is changed. The aturation weighted formulation for the miscible phase elative permeability is used in CO2-Prophet. Incremental il recoveries at the end of the WAG period are shown in ıe table for three different magnitudes of the endpoint gas) oil relative permeability ratio. All input parameters are ıe same as previously discussed except for the gas to oil ndpoint relative permeability ratios. The predicted oil ecovery increases for CO2-Prophet and the compositional mulators as this ratio is decreased. The predicted differnce in oil recovery is less between CO2-Prophet and ither of the two compositional simulators then between ıe two compositional simulators themselves.

he predicted recovery is also shown for the standard mixıg parameter formulation (in which the miscible phase elative permeability is set equal to that of the oil). Under iiscible conditions, this recovery does not change if the as relative permeability is changed. The standard ırmulation produces good results if the gas relative ermeability curve is similar to that for the oil. Situations which the standard formulation introduces inaccuracies e discussed by Prieditis and Brugman[7].

CONCLUSIONS

A new water and CO2 flood prediction software oduct, CO2-Prophet, has been developed for use on ersonal computers. It overcomes many of the limitations the DOE's CO2 Predictive Model (CO2PM). CO2-ophet can simulate many different injection schemes cluding waterfloods, CO2 floods, WAG floods, or any ımbination of these.

CO2-Prophet computes streamtubes between injection ıd production wells. It then makes flow computations ong the streamtubes. An enhanced mixing parameter proach is used for simulation of the miscible process. ıe enhancement permits the incorporation of gas relative rmeabilities in modeling the miscible process.

Ease of use was emphasized in the development of the er interface. Easy to use drop down menus are available. new case can be set up very quickly.

CO2-Prophet compares very favorably with the edictions of the Higgins-Leighton waterflood model and th the predictions of commercially available mpositional simulators. The oil recovery predictions of)2-Prophet are very similar to those of compositional nulators for cases without areal heterogeneity and thout vertical transmissibility.

CO2-Prophet is a very good tool for screening and en for forecasting both waterfloods and CO2 floods ıen a great deal of reservoir description is not available.

CO2-Prophet is being made available to the industry.

NOMENCLATURE

k_{rg} = relative permeability to gas
k_{rm} = miscible phase relative permeability
k_{ro} = relative permeability to oil
k_{row} = oil-water relative permeability
k_{rs} = solvent relative permeability
S_g = gas saturation
S_o = oil saturation
S_{orm} = miscible residual oil saturation
S_w = water saturation

ACKNOWLEDGMENTS

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APPENDIX

INPUT TO MODELS

:luids:

Oil viscosity	1.23 cp
Water viscosity	0.7 cp
CO_2 viscosity	0.065 cp

.eservoir parameters:

Dykstra-Parsons coefficient	0.75
Number of layers	5
Pattern type	5-spot
ω mixing parameter	0.666

elative permeability curve parameters:

S_{orw}	residual oil to waterflood	0.40
S_{org}	residual oil to gas flood	0.25
S_{gr}	residual gas saturation	0.05
S_{sr}	residual solvent saturation	0.05
Swc	connate water saturation	0.15
Swir	residual water saturation	0.15
krocw	endpoint oil rel perm	0.295
kwro	endpoint water rel perm	0.27
krse	endpoint solvent rel perm	0.10
krgcw	endpoint gas rel perm	0.10
now	oil curve exponent	2.36
nw	water curve exponent	2.10
ns	solvent curve exponent	3.17
ng	gas curve exponent	3.17

ıese parameters are used in analytical relative perme-ility equations. The equations are provided in reference 7 d the CO2-Prophet manual.

TABLE 1

PRE-SET PATTERNS

5 Spot
7 Spot (incomplete inverted nine spot)
Inverted 9 Spot
Line Drive (opposed wells)
4 Spot (same as true 7 spot)
2 Spot (isolated 2 well pattern)

TABLE 2

INCREMENTAL OIL RECOVERY (%OOIP)

AT END OF WAG PERIOD

	Gas to oil endpoint relative permeability ratio.			
Model	3.4	1.00	0.34	0.034
CO2-Prophet	15.7	16.9	17.1	17.8
VIP-EXEC(COMP)	15.3	-	17.4	18.8
COMP 3	15.4	-	16.5	16.9

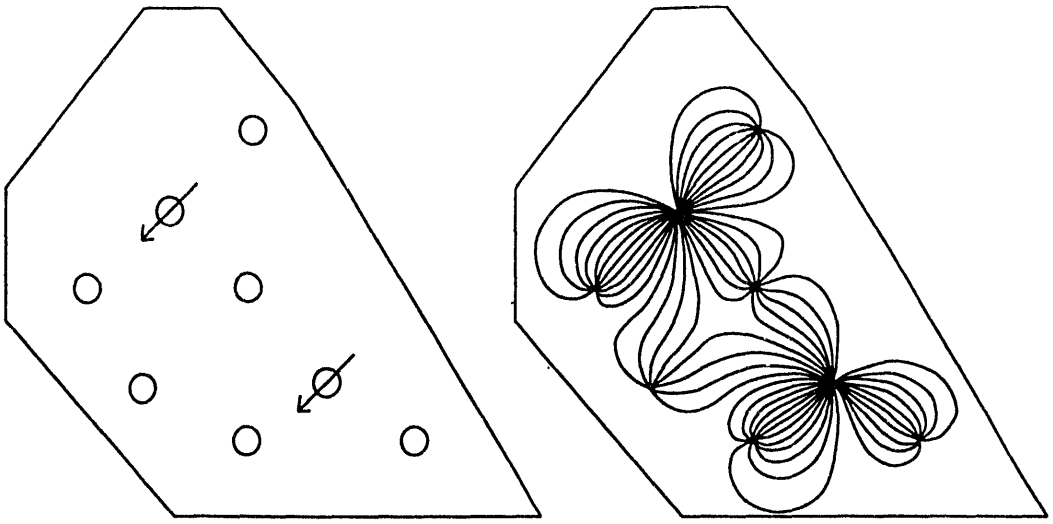

Figure 1. Example pattern and streamlines generated by CO2-Prophet.

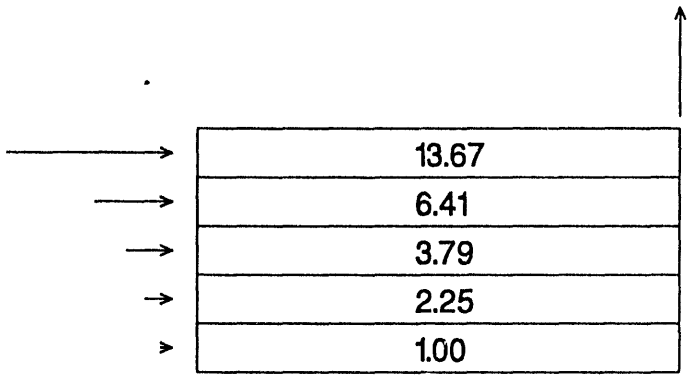

Figure 2. CO2-Prophet initial relative injectivity resulting from a Dykstra-Parsons coefficient of 0.7.

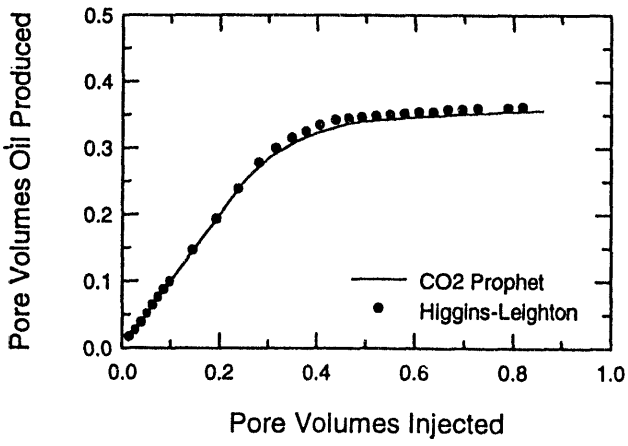

Figure 3. Comparison of CO2-Prophet with Higgins-Leighton model.

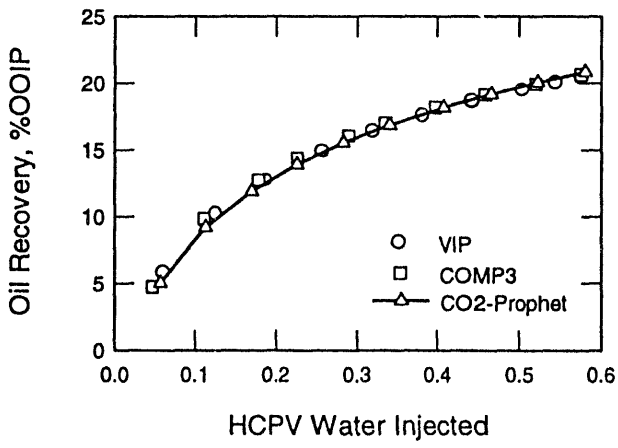

Figure 4. Waterflood comparison between VIP, COMP3, and CO2-Prophet.

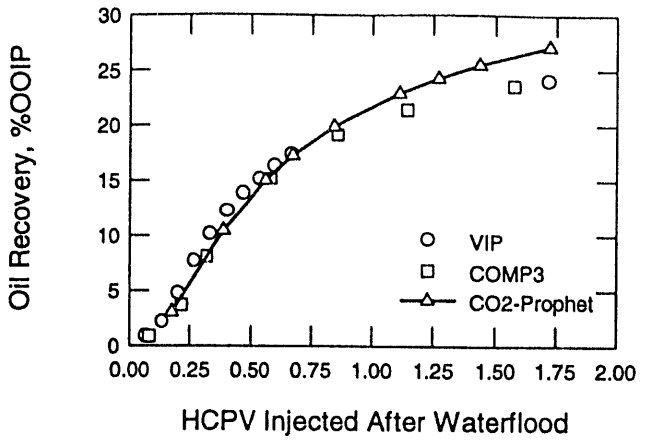

Figure 5. Comparison of CO2-Prophet with VIP and COMP3, 1:1 WAG, cummulative oil production.

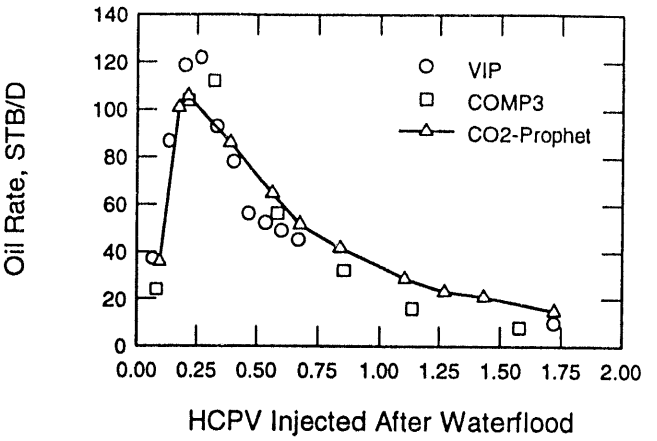

Figure 6. Comparison of CO2-Prophet with VIP and COMP3; 1:1 WAG, oil rate.

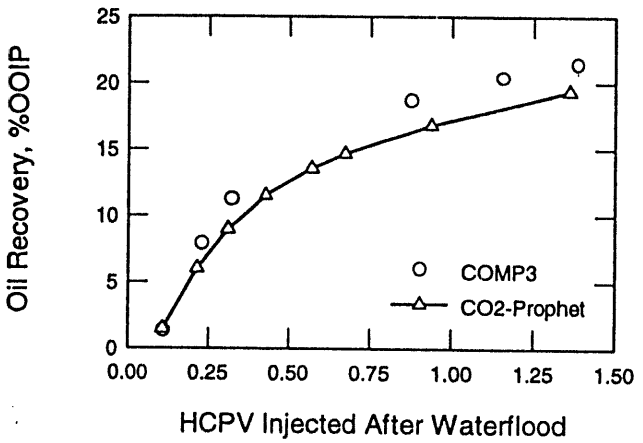

Figure 7. Comparison of CO2-Prophet with COMP3, continuous tertiary CO2 flood.

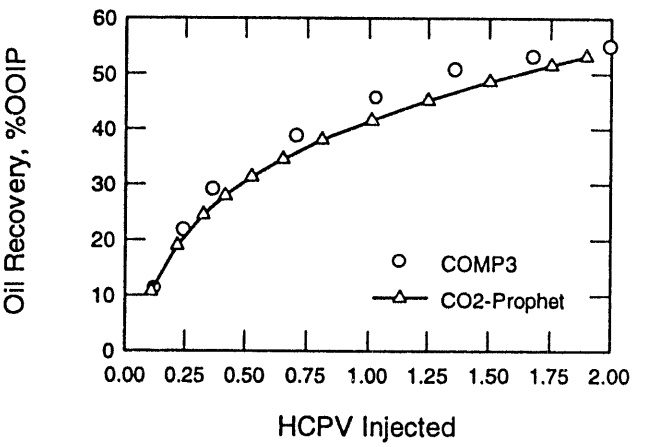

Figure 8. Comparison of CO2-Prophet with COMP3, continuous secondary CO2 flood.

DATE

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7/18/94

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