THE SLAUGHTER ESTATE UNIT CO_2 FLOOD: A COMPARISON BETWEEN PILOT AND FIELD SCALE PERFORMANCE *

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ABSTRACT

This paper describes the performance of both a pilot and a Unit-wide carbon dioxide (CO_2) flood in the Slaughter Estate Unit, Slaughter Field, Hockley County, Texas. The performance and design of both projects are compared and contrasted. The comparison yields insight into the process, the impact of flood design variables, and the effects of project scale.

Between 1976 and 1984, Amoco Production Company conducted a pilot flood consisting of a double five-spot pattern of twelve acres in the Slaughter Estate Unit. A stream of CO_2 and hydrogen (H_2S) sulfide gas was injected using an alternating gas water injection ratio of 1:1 followed by chase gas. A 65% hydrocarbon pore volume (HCPV) slug of gas was ultimately injected.

The pilot project has been the topic of several SPE papers. This paper summarizes the performance to provide a basis for comparison with the performance of the Unit-wide project.

The pilot performance was extremely encouraging and supported a recommendation to implement a field scale flood in the Unit. In 1982, Amoco approved a project to start up a Unit-wide CO_2 flood and injection began in late 1984. The original design of the Unit-wide flood involved injecting a 30% HCPV slug of pure CO_2 using a 2:1 gas alternating water injection ratio. In response to changing oil prices, the gas-water injection ratio and slug size have been modified to maximize the profitability of the project. The resultant gas-water injection ratio scheme is also expected to improve vertical sweep and reduce gas handling requirements. The Unit-wide project has responded very favorably to the injection of CO_2.

INTRODUCTION

Amoco Production Company drilled an "oil-in-the-tank" pilot in the Slaughter Estate Unit to better understand the miscible gas process. The pilot was waterflooded from 1972-1976. In August 1976, miscible gas injection was initiated in the pilot. The initial gas stream contained an acid gas (72% CO_2 and 28% H_2S on a mole basis). The acid gas was eventually replaced with a chase gas (various concentrations of residue gas and nitrogen). Water was injected alternately with the gas. The pilot was completed in July 1984. A reservoir description of the pilot and surrounding area was obtained by starting with geological and pressure transient data, and then modifying parameters which were least known to match primary and waterflood performance.[1] The reservoir description was important for quantitative[2] interpretation of the tertiary performance. Pilot design, performance[3]

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through 1981, and mechanical design considerations[4] were subjects of other technical papers.

The favorable tertiary oil response from the pilot provided comfort with the CO_2 flood process and Amoco initiated a Unit-wide CO_2 flood in December 1984. Previous feasibility studies were used to design a fieldwide CO_2 flood. Reservoir descriptions for various segments of the Slaughter Estate Unit had been developed by history matching primary and secondary (waterflood) performance. Once history matched, CO_2 predictions were made for a variety of conditions to determine the most profitable manner to inject CO_2. Ongoing CO_2 flood modeling has been part of the reservoir monitoring process. With changing oil prices, additional CO_2 flood predictions were made resulting in changes in the slug size, and grading of the gas-water injection ratio to improve vertical sweep.

This paper updates pilot performance through termination of the pilot, describes how the tertiary performance was matched, and compares and contrasts pilot and Unit performance. The procedure employed for fieldwide design is also discussed.

Slaughter Estate Unit Miscible Gas Pilot

The Slaughter Estate Unit tertiary pilot was one of several miscible gas enhanced oil recovery pilots which Amoco operated in the Permian Basin of West Texas. The pilot was located in the Slaughter Estate Unit of the Slaughter Field in Hockley County, Texas (Figure 1). The Slaughter Estate Unit Pilot was a 12-acre, double five-spot "oil-in-the-tank" pilot. The pilot producers were completely surrounded by pilot injectors in order that the producers would only be affected by the fluids injected in the pilot injectors. The Slaughter Estate Pilot was drilled in 1972 in an area of the Unit that had only undergone volumetric depletion. The pilot was then waterflooded from November 1972 to August 1976. The predicted volume of oil drained from the pilot prior to waterflooding was 60.7 MSTB (9.4% OOIP).[1] The pilot oil recovery during waterflood operations was 191.9 MSTB, or 29.9% OOIP. The model predicted additional oil recovery for continued waterflood operations through pilot termination to be 72.0 MSTB (11.2% OOIP). Using the predicted recoveries plus the actual waterflood oil recovery, the ultimate primary plus secondary oil recovery for the pilot is 324.6 MSTB or 50.5% OOIP.

An alternate acid gas (72% CO_2 and 28% H_2S)-water injection project was initiated in August 1976. Acid gas and water were injected over 10 cycles at a gas-water injection ratio (GWR) of 1:1 (1 RB/RB). A 25% HCPV slug of acid gas was injected. The pilot oil production rate increased from 37 STB/D to a peak of 152 STB/D in February 1979 (Figure 2). Chase gas injection began in October 1979. The chase gas was composed of residue gas or nitrogen, depending on the available supply. The chase gas was immiscible with the Slaughter Estate oil, but was first-contact miscible with the acid gas. A 40% HCPV slug of chase gas was injected over 11 cycles. After five chase gas cycles, the

GWR was reduced to 0.7:1.0 to improve vertical sweep. Chase gas injection was completed in June 1982. Chase water injection continued until July 1985. The incremental tertiary oil recovery from the pilot was 125.9 MSTB (19.6% OOIP).

The reservoir description[1] of the Slaughter Estate Pilot and the surrounding area was used with the contact miscible solvent relative permeability model[5,6] to interpret tertiary pilot performance. The performance of the pilot was satisfactorily matched. Figures 3-6 show typical matches of tertiary performance obtained. In the model, the fluid injection and production rates were specified on a reservoir barrel basis to allow the pilot injection withdrawal ratio to be met. Matching the injection withdrawal ratio is required to ensure the correct volumes of fluid enter and leave the pilot. The accuracy of the match is judged by the ability to match oil rate, GOR, WOR, and bottomhole pressures. The reservoir description from the waterflood history match[1] was not changed. This predicted tertiary oil response and acid gas response occurred at the same time. This phenomenon, which is consistent with a high level of dispersion, occurred in the Slaughter Estate Pilot, as well as other Amoco CO_2 pilots. The timing of the predicted peak tertiary oil response is slightly off (Figure 3). This may be due to slight errors in the reservoir description. Chopra[6] found that a miscible gas flood is more sensitive to reservoir heterogeneities than is a waterflood. The solvent relative permeability concept[5,7] was necessary to match the maximum 50% loss of water injectivity experienced (1979). The solvent relative permeability, important in matching gas injectivity and gas production, lies below the oil relative permeability curve in the presence of a final oil saturation.[5] Since the average reservoir pressure of 2000 psi was well above the minimum miscibility pressure of 1050 psi, loss of miscibility had little effect on the predicted tertiary performance.

Water bottomhole injection pressures were in the 2800-3100 psi range, depending on each well's fracture parting pressure. The pilot gas injection rate was maintained equal to the pilot water injection rate to maintain a GWR of 1.1. The acid gas bottomhole injection pressures usually ran about 100 psi below the water bottomhole injection pressures. During chase gas, the bottomhole injection pressures were 2500 psi. This lower bottomhole pressure resulted in equal gas and water injection rates on a reservoir barrel basis. Bottomhole producing pressures started out at about 200 psi, but near the end of acid gas injection, climbed to 600 psi. High gas rates caused difficulties in pumping off the pilot producers. Bottomhole producing pressures were eventually lowered by removing vent strings and packers to allow the gas to flow up the annulus.

Modeling Tertiary Pilot Performance

The chase gas was assumed to be miscible with the oil in the model.[5] This assumption, although not true, is allowable so long as the chase gas bank does not overrun the acid gas bank. This did not happen in the predictions. Based on numerical dispersion, the Peclet number along the diagonal between pilot injector-producer pairs was 16. With the excellent tertiary oil response, it is unlikely that the chase gas bank overran the solvent bank.

The model in Reference 5 assumes stabilized displacement (no viscous fingering). Fractional flow calculations similar to that presented by Stalkup[8] were used to estimate the maximum GWR allowed for stable displacement. The maximum GWR was 19 for the Slaughter Estate Pilot relative permeability (Figure 7). This calculation uses the solvent relative permeability curve.[5]

The modeling of pilot tertiary performance indicated that the final oil saturation to the acid gas was 5% PV. This value was obtained by determining which specified final oil saturation yielded the best match in cumulative oil recovered.

The promising tertiary performance of the Slaughter Estate Pilot provided Amoco with confidence in 1982 to approve a Unit-wide CO_2 flood. H_2S was not considered for fieldwide injection with CO_2 because of safety reasons and is still not considered.

Slaughter Estate Unit History

The Slaughter Estate Unit comprises 5752 acres in the southeast portion of Slaughter Field. Average net pay is 79 ft. with average porosity of 12.0% and average permeability of 4.9 md. Other pertinent data can be found on Table 1.

The Slaughter Estate Unit was formed in December 1963. Prior to unitization, limited waterflooding had occurred on various leases which were to comprise the Unit. Before unitization, the leases were allowable restricted and oil production almost doubled due to the increased Unit allowable. From unitization until 1968, some 16 injectors were added with the allowable going up accordingly. In 1968, a 25% injection bonus allowable was given to the Unit which put the Unit capacity under the allowable for the first time.

Approximately 125 wells were drilled from 1969 through 1974, mainly in the southern two-thirds of the Unit. Approximately 70 conversions to water injection were also made during this time. Unit production rose from around 8000 BOPD to a peak of 23,500 BOPD in 1974 (Figure 8).

The two predominant patterns in the Slaughter Estate Unit are five-spot and the chicken wire patterns. The southwest portion of the Unit is drilled on 20 acre five-spot patterns. The southeast portion of the Unit is drilled on 160 acre chicken wire patterns (Figure 9), while the northern portion of the Unit contains 40 acre five-spots.

During waterflood, the Unit was operated under the following philosophy: Ensuring all the pay was open in both injectors and producers, keeping the producing wells pumped off (<500' fluid level) and injecting below formation parting pressure. The Unit showed typical waterflood performance with high water injection as fill-up occurred followed by a decrease in water injection between fill-up and water breakthrough (Figure 8). The GOR also collapsed during this time and water breakthrough occurred in 1967.

Oil response was observed beginning in 1965. From unitization in 1963 until 1968, it was difficult to notice response because the Unit was allowable limited. Several infill drilling packages occurred between 1969 and 1974 all of which were undertaken to enhance waterflood recovery. Oil production peaked in 1974 at 23,500 BOPD and began a 12% annual decline until 1983. During 1983 and early 1984, an infill drilling package was implemented in the northern portion of the Unit. This was done to standardize the patterns and to prepare for CO_2 flooding. This infill drilling package halted the waterflood decline and held oil production flat during this time.

CO_2 Model Study

Amoco studied the feasibility of implementing Unit-wide CO_2 flooding in several West Texas properties. Preliminary pilot results were favorable as were the potential economic incentives. A method was formulated[9] which allowed Amoco to study the feasibility in a timely manner. Several rounds of studies were completed between 1978 and 1982. With the encouraging results from the Pilot and feasibility studies, the Unit-wide implementation of CO_2 flooding for the Slaughter Estate Unit was authorized in 1982. CO_2 injection began in December 1984.

While undergoing CO_2 flooding, reservoir modeling has been used as a tool for monitoring performance. There have also been several detailed geologic studies completed as well as a new model developed for miscible flooding.[5] These new data and tools were utilized in the most recent model study.

History Matching

The Unit was history matched for both waterflood and early tertiary performance, utilizing the latest geologic data and techniques[10] for developing a reservoir description. Relative permeability data for the Unit were averaged and normalized to the Unit average connate water saturation of 7.5% and average residual oil saturation of 20%. The average water relative permeability hysteresis curve allowed for a trapped water saturation of 12%. The pilot relative permeability had higher residual oil and trapped water saturations (31% and 37%, respectively).

The field was modeled using a similar approach as the feasibility modeling.[9] Average patterns for the waterflood were based on similar development history, geology and waterflood performance. The average pattern models were then scaled up for the full Unit performance.

For the tertiary performance matching, the contact miscible solvent relative permeability model[5] was used. The model was used to match Unit performance through 1988. Both waterflood and tertiary performance were used for the history matching, as matching only the waterflood performance did not yield an accurate enough reservoir description for tertiary performance. The contribution of some of the thin, high k/Ø layers can go unnoticed during waterflooding. Their effect is more pronounced during tertiary flooding due to the high mobility of the CO_2.[6] These high k/Ø layers account for the early gas responses.

The timing of converting wells to alternate gas-water injection (AGWI) was taken into account. Each well in a model area has various injection half-cycle times which were averaged for the model work. The initial GWR was 2:1 using a 1% HCPV half-cycle of CO_2 and a 0.5% HCPV half-cycle of water. The initial GWR was changed twice during the history match period. In August 1986, the GWR increased to 3:1 GWR using a 1.5% HCPV CO_2 half-cycle. In January 1987, the GWR was again increased to 4:1 GWR using a 2.0% HCPV CO_2 slug. The water half-cycle remained the same at 0.5% HCPV during both of these increases. The GWR was increased to increase CO_2 injectivity and in turn accelerate tertiary oil response.

During the history matching of the Unit, several things became obvious. Actual field performance was less than the model predictions using waterflood operating assumptions on the producing wells. That is, the wells have very low producing BHP's and they are in an improved or negative skin condition. Due to problems inherent in pumping gassy wells, the actual measured producing BHP's varied from 140 psi to 300 psi. Additionally, it was found that wells were tending to scale up faster than they had under waterflood. These two factors were taken into account in the model and BHP's were increased on the producers and the effective wellbore radii were reduced.

In order to finally match both the oil and gas performance of the tertiary period, the final oil saturation (S_{of}) had to be increased. The derived S_{of} for the Unit is 12%. Using this value allowed for both tertiary oil response and gas response to be matched. Matches of oil, water and gas production for the 20 acre five-spot patterns (Model Segment No. 1) are shown in Figures 10-12, respectively. These plots represent the average of four five-spot patterns. CO_2 flood performance starts in 1985. Prior performance represents waterflooding.

Tertiary Performance

The Slaughter Estate Unit is experiencing tertiary response due to CO_2 flooding (Figure 8). The decrease in oil production seen in 1985-86 was expected due to the loss of injectivity experienced with AGWI floods.[3] The initial loss was not as great as expected, based on pilot experience, partly because of the staging of the CO_2 injection implementation. The current oil rate is approximately 4000 BOPD above the predicted waterflood decline (Figure 13).

The various areas of the field are in different stages of tertiary performance due to well spacing and startup of CO_2 injection. The 20 acre five-spot patterns in the southwest of the Unit are the most mature with an average of 26% HCPV CO_2 injected, although they were the last be put on CO_2 injection. Figure 14 shows typical producing well performance for this area. The CO_2 production seemed to lead the tertiary oil response, beginning in late 1986. The water production began declining when the CO_2 production rate began to increase.

The chicken wire patterns in the southeast portion of the Unit are the least mature area with an average of 11% HCPV CO_2 injected. Figure 15 shows typical producing well performance for this area. The characteristic shape of the CO_2, oil and water curves are similar to the performance of the five-spot pattern producer shown in Figure 14. The tertiary oil response in Figure 15 did not occur until 1988. Other areas of the field are between these two in their maturity and response.

The relative losses of injectivity for water and CO_2 are shown in Table 2. The losses of injectivity are relative to the pre-CO_2 water injectivity. The cycle numbers in Table 2 are based on a statistical sampling criteria of 30% of the wells achieving that cycle. The most mature patterns have experienced the greatest injectivity loss.

Injection profiles were not markedly different between waterflooding and CO_2 flooding. The profiles indicated that the same intervals were swept during waterflooding and CO_2 flooding.

CO_2 retention is very good, cumulative injection is 146 BCF and cumulative production is 13 BCF for a retention of 91% (Figure 16). The initial plans called for a total slug of 30% HCPV at a constant 2:1 GWR. Current plans call for reducing the GWR's from the 4:1 level to improve sweep and to inject a larger total slug. These changes were brought about by changes in oil prices, CO_2 prices and recycle costs. The eventual total slug size and ultimate tertiary recovery will be dependent on future changes in the economic climate.

Comparison of Pilot and Field Tertiary Performance

The Slaughter Estate Pilot and Unit both experienced tertiary response. The performance is similar. CO_2 breakthrough was observed at the first sign of tertiary oil response. The ratio of the peak tertiary oil rate to the peak waterflood oil rate was 0.5 for both the pilot and Model Segment No. 1. The Unit chicken wire patterns are expected to have a slightly lower ratio. The lower ratio is because the individual producers in the chicken wire pattern peak at different times. The decline in tertiary oil rate is expected to be slower in the chicken wire patterns. The percentage oil recovery will probably be less in the Unit than the pilot. There are several factors which cause the lower recovery. First, the pilot had a larger tertiary target. The minimum displaceable tertiary oil saturation (residual oil saturation to waterflooding minus model estimated final oil saturation to CO_2) was estimated to be 26%. In the Unit, the minimum displaceable tertiary oil saturation is estimated to be 8%.

The Unit had higher GWR's which helped increase the oil and gas production rates and may have also led to some viscous degree of fingering. Figure 17 shows fraction flow calculations for the average Slaughter Estate Field relative permeability curves. The maximum GWR above which viscous fingering is estimated to occur is 1.9:1. The initial GWR in the Slaughter Estate Unit was 2:1, then was increased to 4:1 to accelerate rates. Therefore, there may be some viscous fingering[11-13] which could lead to a higher effective final oil saturation. Some of the oil might be bypassed due to the nonequilibrium effects associated with viscous fingering.[12]

The maximum loss in water injectivity was similar in the pilot and Unit. The water injectivity loss in the pilot is partly due to a larger trapped water saturation in the pilot. The Unit loss in water injectivity is primarily due to the higher final oil saturation to CO_2 which reduces the solvent relative permeability and the maximum water relative permeability.[5]

Gas injectivity is difficult to compare between the pilot and the Unit. The acid gas injection rates in the pilot were lower than the Unit-wide CO_2 injection rates. Lower bottomhole injection pressures for acid gas than water make this comparison difficult.

The degree of stratification is only slightly different between the Slaughter Estate Pilot and Unit. A Lorenz coefficient plot for the pilot and Model Segment No. 1 of the Slaughter Estate Unit (Figure 18) shows the pilot is slightly more stratified. The Lorenz coefficients were 0.41 and 0.37 for the pilot and Model Segment No. 1, respectively. In matching the Unit performance, the fastest layer was broken up in two layers to provide a small pore volume faster layer (high $k/\emptyset$). This may be due to lack of sensitivity of reservoir layering to waterflooding[6] or may be due to viscous fingering.

This faster layer was not always apparent from core or log data. Since the predictive model did not account for viscous fingering,[5] the high $k/\emptyset$, small $\emptyset h$ layer may represent an artifact to account for viscous fingering in the fastest layer. Larger cycles sizes which occur in the faster layers may not fully stabilize the solvent-water bank.

CONCLUSION

1. The Slaughter Estate Unit Pilot tertiary oil recovery was significant. Incremental tertiary oil recovery was 19.6% OOIP. This is attributed to the success of acid gas mobilizing tertiary oil.

2. The "oil-in-the-tank" pilot concept was valuable for advancing our understanding of the miscible gas performance. The data from the pilot was

used for validation of the contact miscible solvent relative permeability model and was successfully used in evaluating Unit-wide performance. The Slaughter Estate Unit Pilot performance provided Amoco's management comfort to initiate a Unit-wide CO_2 flood.

3. The Slaughter Estate Unit is responding to CO_2 flooding. The current incremental oil rate is 4000 BOPD.

4. There have been differences in the Unit and the pilot CO_2 flood responses. These differences appear to be caused by variations in residual oil saturation to waterflooding, the final oil saturation to miscible gas flooding, and higher initial gas-water injection ratios.

5. The higher gas-water injection ratios used in the Unit CO_2 flood may have caused some viscous fingering which may lead to lower oil recovery.

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NOMENCLATURE

BHP	Bottomhole Pressure, psi
GWR	Gas-Water Injection Ratio, RB/RB
k	Permeability, md
S_{of}	Final Oil Saturation to Miscible Gas Displacement, Percent Pore Volume
Ø	Porosity, Percent Pore Volume

ACKNOWLEDGMENTS

We thank Amoco Production for permission to publish this paper.

Table 1
Pertinent Data Sheet

Working Interest	-	98.5%
Producing Area	-	5,703 Acres
Original Oil-in-Place	-	283 MMBO
Formation	-	San Andres Dolomite
Depth	-	4,985 ft.
No of Wells	-	202 Producers
	-	147 Injectors
Producing Mechanisms		
Primary	-	Solution Gas Drive
Secondary	-	Waterflood
Tertiary	-	CO_2 Miscible
Average Pay	-	Gross 140 ft.
	-	Net 79 ft.
Average Porosity	-	12.0%
Average Permeability	-	4.9 md
Oil Gravity	-	32° API

Table 2
Loss of Injectivity

		% Injection Reduction	Cycle Number
Total Unit	CO_2	31	15
	Water	49	15
20 Acre Five-Spot Patterns	CO_2	40	16
	Water	57	16
160 Acre Chicken Wire Patterns	CO_2	16	9
	Water	49	9

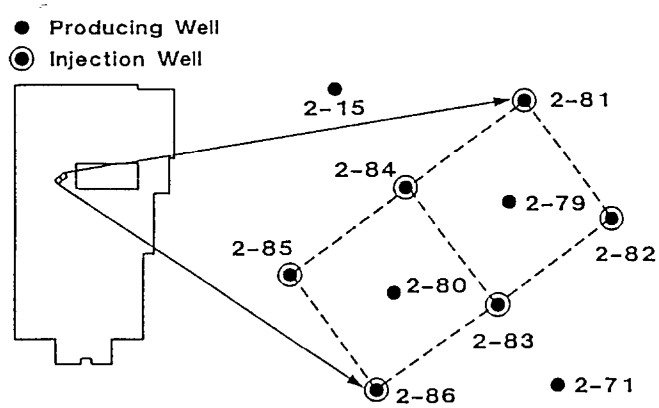

Figure 1 - Slaughter Estate Unit tertiary pilot

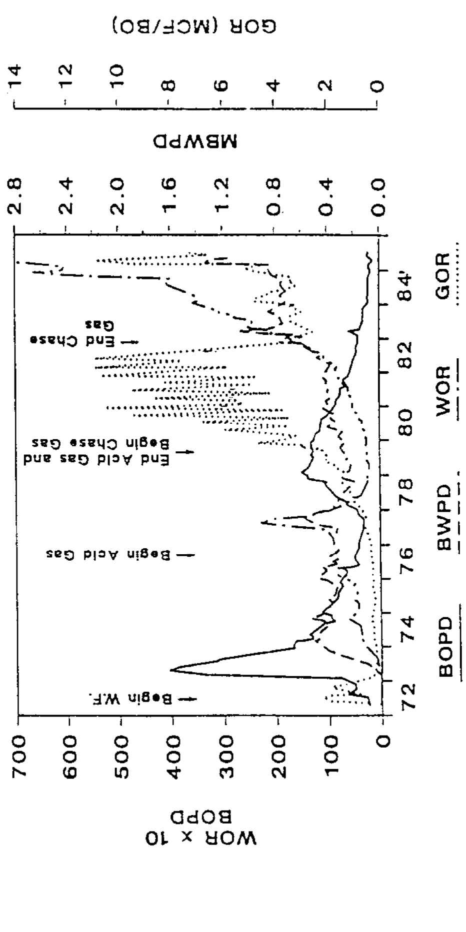

Figure 2 - Slaughter Estate Unit pilot performance

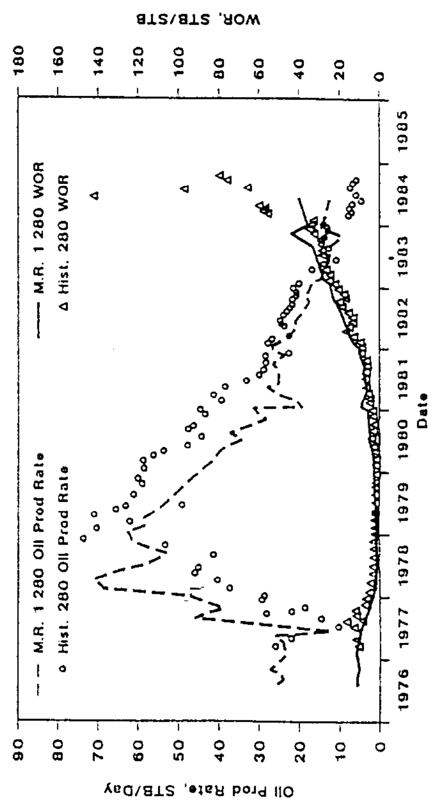

Figure 3 - Tertiary pilot oil and WOR matches, Well 280

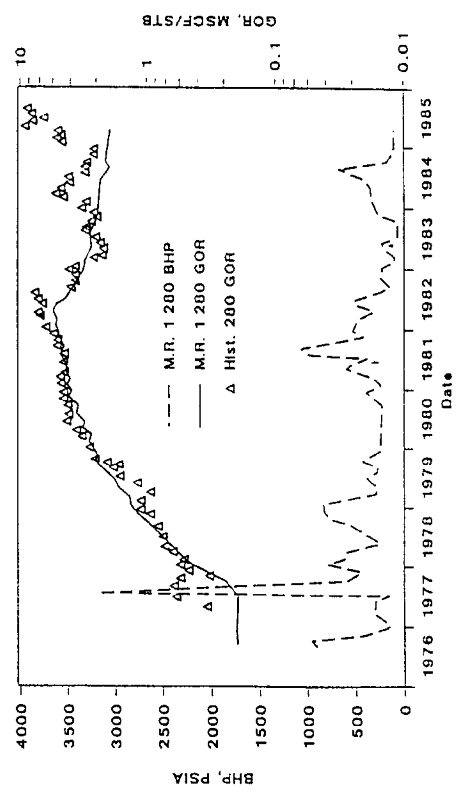

Figure 4 - Tertiary pilot GOR match, Well 280

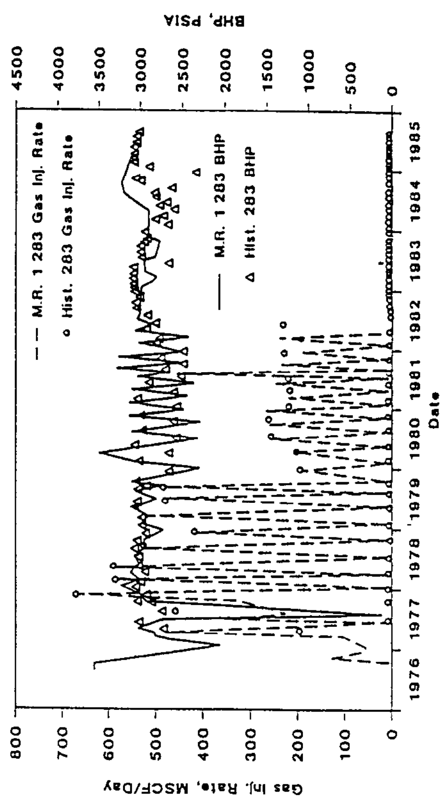

Figure 5 - Tertiary pilot gas injection match, Well 283

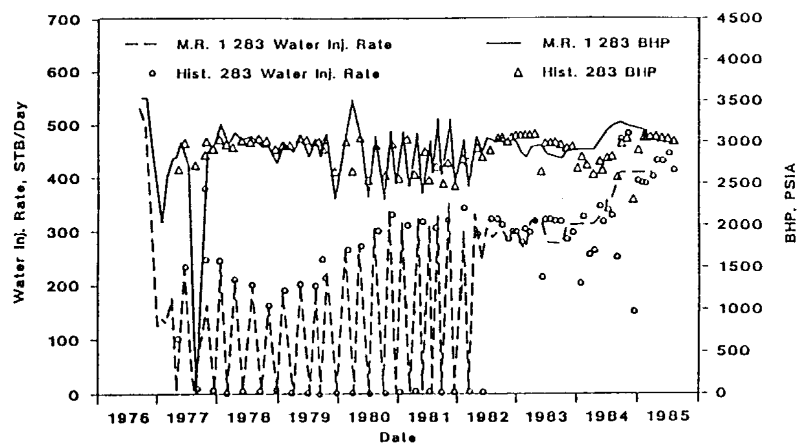

Figure 6 - Tertiary pilot water injection match, Well 283

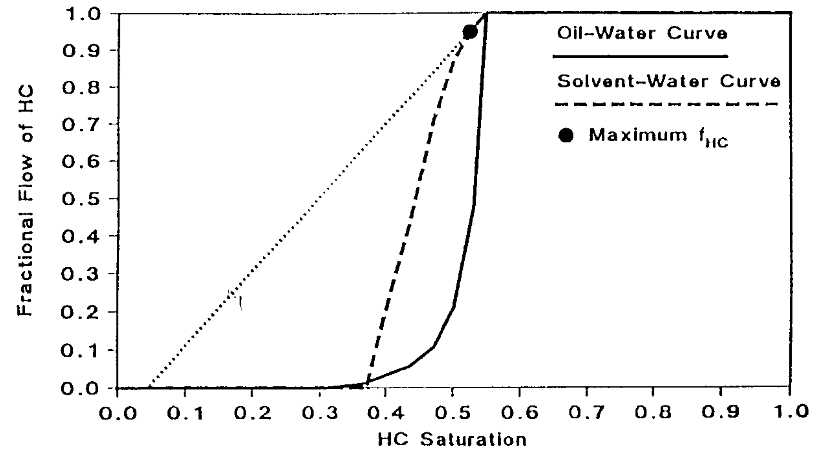

Figure 7 - Pilot maximum GWR (gas/water injection ratio=19)

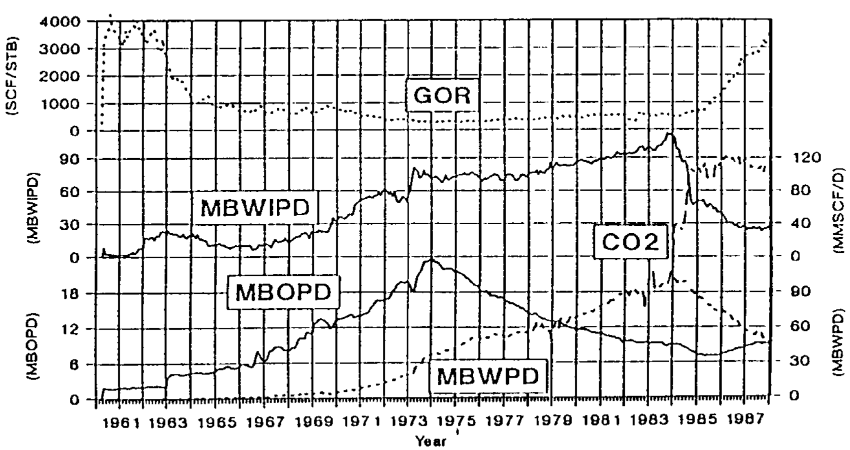

Figure 8 - Slaughter Estate Unit performance

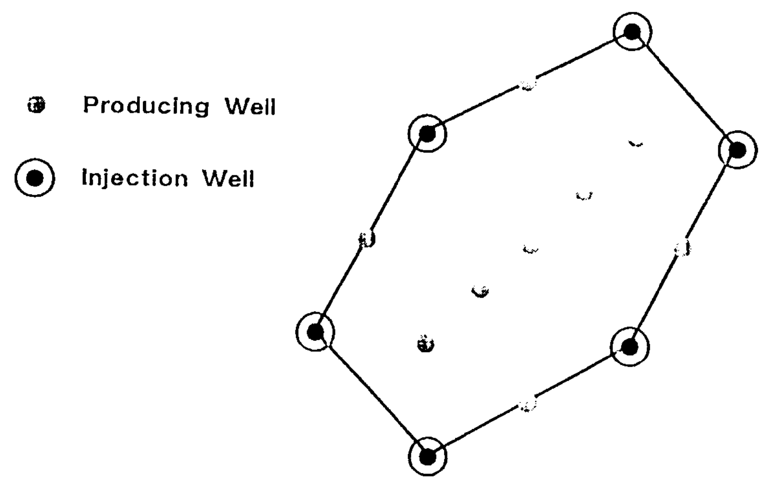

Figure 9 - 160-acre chicken wire pattern

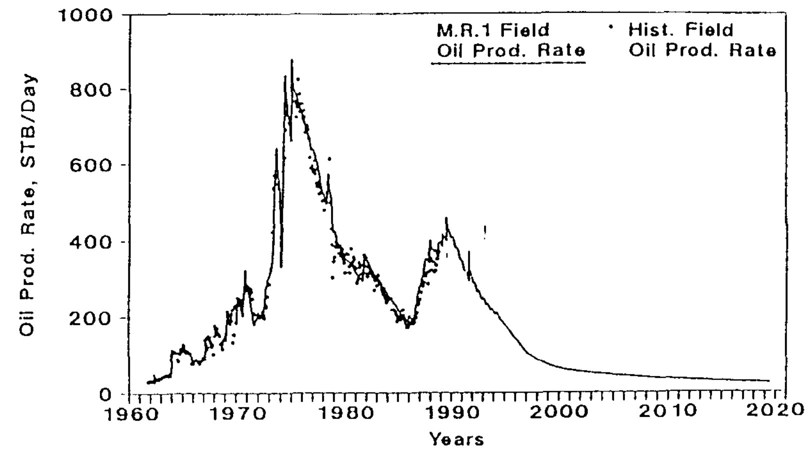

Figure 10 - Slaughter Estate Unit model Segment No. 1 oil rate

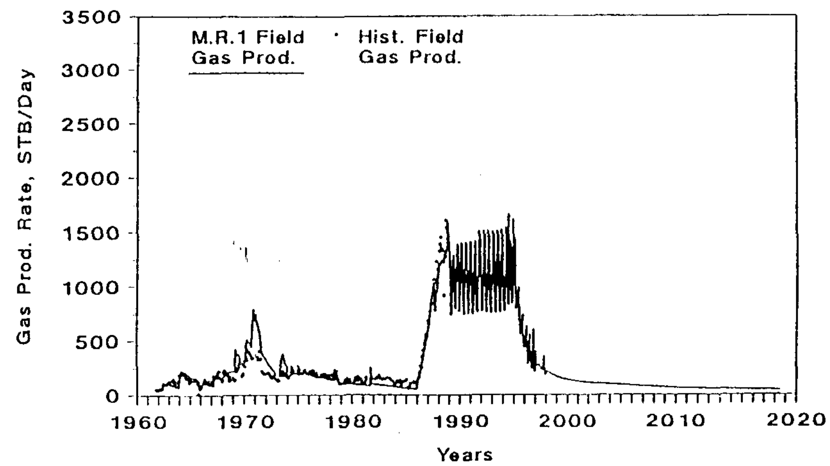

Figure 11 - Slaughter Estate Unit model Segment No. 1 gas production rate

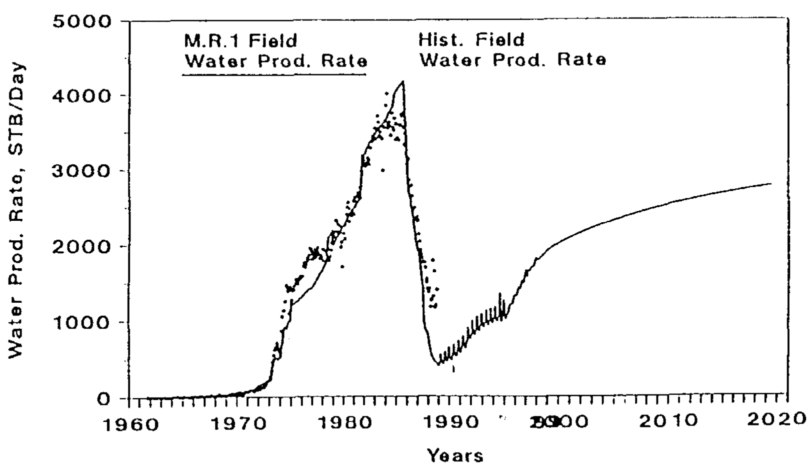

Figure 12 - Slaughter Estate Unit model Segment No. 1 water production rate

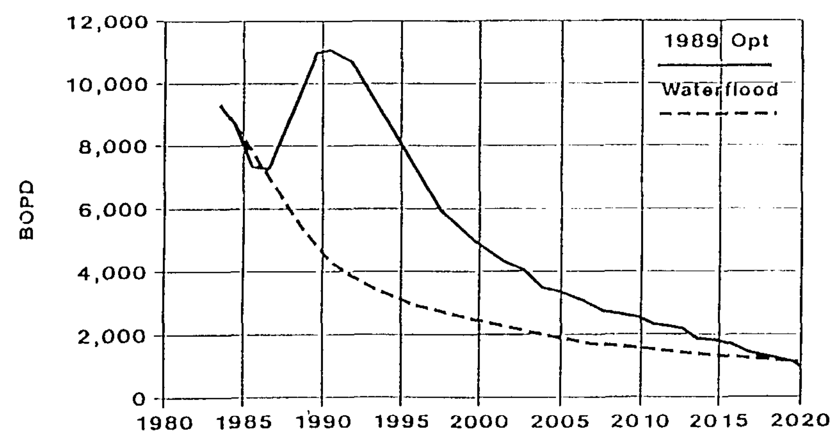

Figure 13 - Slaughter Estate Unit predicted waterflood and tertiary oil rates

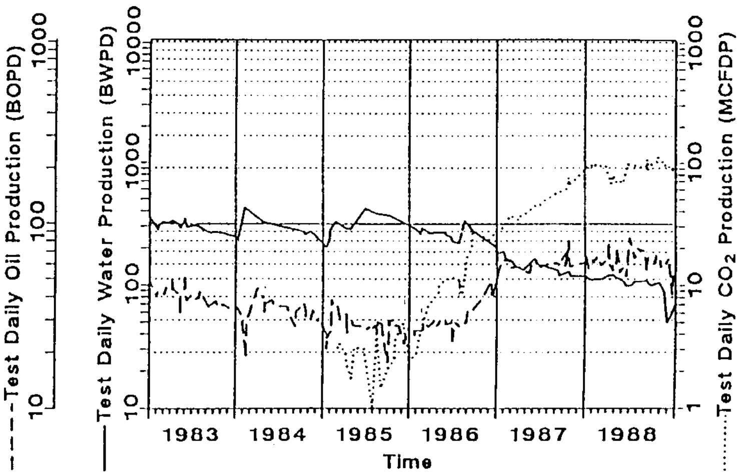

Figure 14 - CO_2 flood performance, Well A

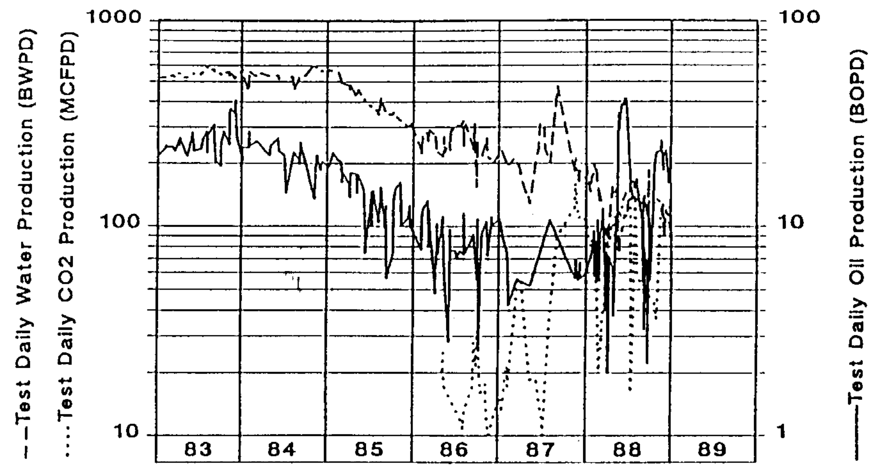

Figure 15 - CO_2 flood performance, Well B

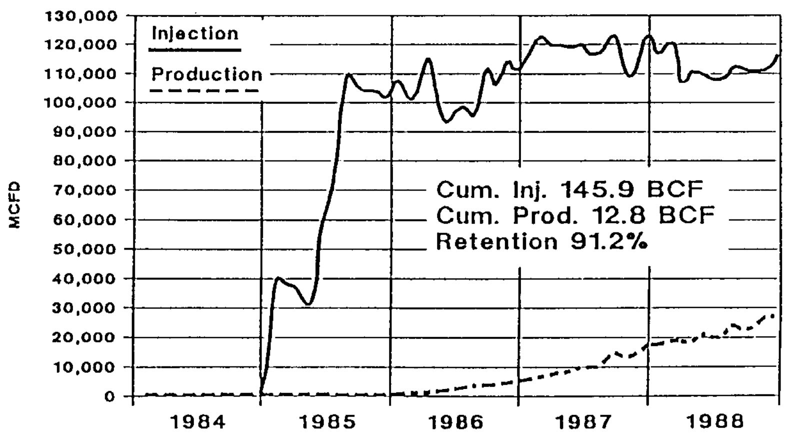

Figure 16 - Slaughter Estate Unit CO_2 production

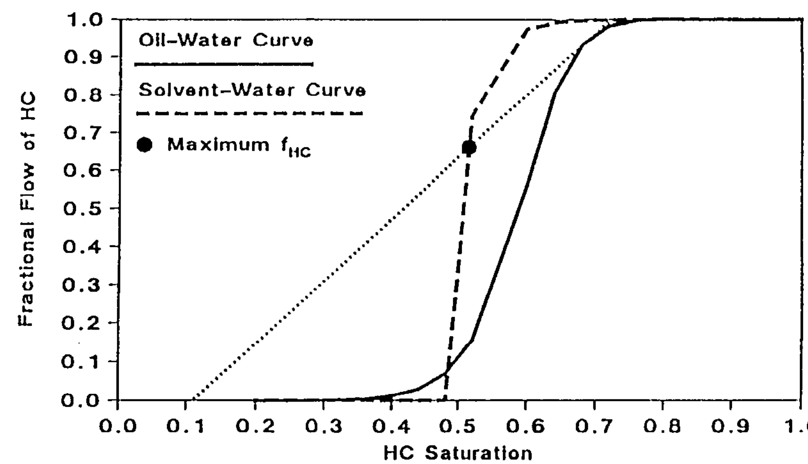

Figure 17 - Unit maximum GWR (gas/water injection ratio=1.9)

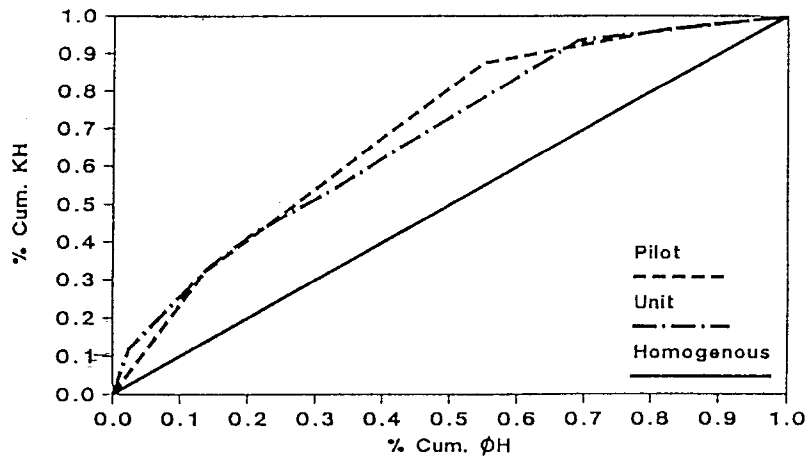

Figure 18 - Lorenz coefficient