SIMULATION OF A CO_2 FLOOD IN THE SLAUGHTER FIELD WITH GEOSTATISTICAL RESERVOIR CHARACTERIZATION

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Abstract

Texaco has been operating a CO_2 flood in the Sundown Slaughter Unit in Hockley County, Texas since January of 1994. The CO_2 flood was originally justified by analogy with an adjacent CO_2 flood. A CO_2 flood simulation was later done to predict and optimize the performance of the flood. With actual production data from the CO_2 flood available, the simulation forecast was redone and updated. Specific objectives of this new, revised simulation study were to use geostatistical reservoir characterization to improve the representation of reservoir heterogeneity and to use more representative relative permeability curves and residual saturation values.

A team was formed for the new simulation study which included both geologists and engineers with members both from the operating division and Texaco's research organization. Four new geostatistical reservoir models were developed, each with a different level of effective heterogeneity. The basic idea was to adjust the reservoir characterization to improve the CO_2 flood match and forecast. All the new models as well as the old model could be used to match the waterflood history equally well with moderate adjustments in the water-oil relative permeability curves. The correct level of reservoir heterogeneity was not needed to do a waterflood match. However, all the models were not equally valid in matching and predicting CO_2 flood performance. The predicted CO_2 flood performance was substantially different for these models and indicates that a good waterflood history match is not sufficient for a good CO_2 flood prediction.

The reservoir heterogeneity in a model must be substantially correct for a successful CO_2 flood match. Adjusting the gas relative permeability curve for a CO_2 flood history match can compensate for moderate, but not large, errors in the reservoir heterogeneity.

This paper describes the methods used for conducting the waterflood and CO_2 flood history matches, for making the CO_2 flood forecast, and for evaluating the different geostatistical realizations. In addition, the important sensitivities of a tertiary CO_2 flood forecast to the reservoir description and the gas relative permeability are discussed and quantified.

Introduction

The Sundown Slaughter Unit (SSU) in Hockley County, 100 miles north of Midland, Texas, is operated by Texaco. It is one of a number of units in the Slaughter field, located on the Northern Shelf of the Permian Basin. Production is from the San Andres formation, which is Permian in age and composed of shallow marine sequences of carbonates and evaporites. The field was discovered in 1937 and was produced under solution gas drive until 1959, when waterflooding was started. An infill drilling program in the 1970's reduced the well spacing from 35.4 to 17.7 acres per well. A CO_2 flood was started in January of 1994, when the field was already in a very mature stage of waterflooding. The field is currently responding favorably to the CO_2 flood.

The Texaco Slaughter CO_2 flood was originally justified by analogy using dimensionless CO_2 flood performance curves from an offset operator. A CO_2 flood simulation and forecast was later done by Texaco to improve the forecast as well as to optimize operations. This simulation has been previously described in the literature.[1] The CO_2 flood simulation was redone recently with the goal of creating an even better forecast by matching actual production data from the early stages of the CO_2 flood. Objectives of the new simulation study were to use geostatistical reservoir characterization to improve the representation of reservoir heterogeneity and to use more representative relative permeability curves and residual saturation values. A special need and concern was to improve the prediction and match of the initial tertiary oil and CO_2 response. The MORE compositional reservoir simulator was used for the revised study.

Simulation

CO_2 Flood Simulation Area

The area that was used for the new CO_2 flood simulation included 355 acres and was the same as the area used in the previous simulation study.[1] (See **Figures 1** and **2**.) The simulation grid size was 29 blocks by 29 blocks with 16 layers. The wells used for the CO_2 flood in this area and the field are in a configuration similar to a line drive in which rows of injectors are alternated with rows of producers.

Permeability and Porosity Grids

One of the main goals of the new CO_2 flood simulation was to use a permeability and porosity grid model which more accurately represents the actual reservoir geology. The basic idea was to adjust the reservoir characterization to improve the CO_2 flood match and forecast. Initially four new geostatistical grid models were created using conditional simulation, but more would have been created if needed. It was felt that the previous simulation study may have used a permeability grid model that did not have sufficient variation.

For comparison, the final permeability and porosity grid model from the previous Slaughter CO_2 flood simulation was also used in this study. This grid model, which contained sixteen layers, was created by averaging layers from a geological model. (Landmark's Geolink software was used for this averaging process.)

The four new geostatistical grid models are referred to as Case 1 through Case 4 and are described in **Table 1.** Case 1 represented the best estimate while Cases 2 to 4 were attempts to increase the effective heterogeneity even more by adjusting the correlation lengths. Correlation lengths were adjeusted to modify the heterogeneity.

Although Case 2 represented an attempt to increase the effective heterogeneity over that present in Case 1, the attempt was not successful. The effective heterogeneity in Case 2 was less than in Case 1. Apparently, the slight increase in the vertical correlation length produced a larger effect than the increase in the horizontal correlation length. A small increase in the vertical correlation length significantly reduced the effective heterogeneity in the model.

The type of heterogeneity referred to here is an increase in permeability variation with a long correlation length (i.e., long relative to the distance between wells). This is the type of heterogeneity that leads to increased fluid channeling. A large amount of heterogeneity combined with a very short correlation length acts like an effectively homogeneous permeability structure without much fluid channeling. These production characteristics are based on the continuity of the high permeability streaks between wells as controlled by the correlation length.

The comparative levels of heterogeneity in the permeability grids could be inferred from fluid flow behavior in the simulations. Increased heterogeneity is associated with lower oil recovery for both the waterflood and the CO_2 flood as well as earlier CO_2 breakthrough (with other inputs, such as relative permeability curves, left unchanged). Although not shown here, comparative levels of heterogeneity were also apparent on plots of the log of the permeability versus the probability (i.e., plots similar to the plots used to compute a Dykstra-Parsons factor).

Waterflood History Matches

Waterflood history matches could be made using the original permeability grid and all four new geostatistical grids. All that was required was ***moderate adjustment of the curvatures of the oil-water relative permeability curves***.

For all cases, the maximum oil relative permeability (*krocw*) was set to 0.9, the maximum water relative permeability (*kwro*) was set to 0.6, and the connate water saturation (*Swc*) was set to 0.12. These values were adopted from the previous simulation. The waterflood residual oil saturation (*Sorw*) was reduced to 0.3 from 0.4. A greater value was used in the previous study, and an objective of the current study was to use a smaller, more representative value.

The adequacy of the waterflood history matches was determined by comparing simulated rates to actual oil and water production rates and simulated cumulative totals to actual water and oil production totals as a function of time. The comparisons for the original grid and the geostatistical cases are shown in **Figure 3**. In addition, the predicted ultimate recoveries for extended waterfloods (i.e., continuing the waterfloods without CO_2 floods) were also very similar (as shown in the last column in **Table 3**). In doing these matches, only the injection rates and production well bottom hole pressures were set. The oil production rates were not set.

The different matches shown here demonstrate that waterflood history matches are not unique. By adjusting the water-oil relative permeability curves appropriately, a given oil and water production history can be matched for a broad range of different assumed permeability variations. The ability to use oil-water relative permeability curve adjustments to compensate for the absence of sufficient reservoir heterogeneity in a model has long been known in the petroleum industry and is the basis of the technique of using "pseudo relative permeability" curves in simulation.[6]

Tertiary CO_2 Flood Forecast: Potential Variation when CO_2 Flood History is Unavailable for Matching

After the waterflood history matches were performed, CO_2 flood performance forecasts were made for all the permeability grid cases ***using the same gas relative permeability*** curve. This would be done if no actual CO_2 flood production data were available. **Figure 4** compares dimensionless tertiary oil forecasts for the different permeability grid cases. **Figure 5** compares dimensionless CO_2 production forecasts. The gas relative permeability curve used in these cases had a maximum value of 0.125. The CO_2 flood injection process for these cases consisted of injection of about a 17% HCPV continuous CO_2 slug followed by an approximately 1.5 to 1 volumetric WAG until a total volume of 50% HCPV CO_2 had been injected. The WAG was followed by a chase water drive.

Unlike the predicted waterflood performance forecasts after the history match, the tertiary CO_2 flood forecasts are very different and are highly dependent on the permeability grids (with their associated reservoir heterogeneities) that were used. The original (least heterogeneous) grid resulted in the highest predicted tertiary oil recovery, higher than all of the geostatistical grids. However, there was still substantial variation in predicted recovery for the geostatistical grids. The dimensionless Denver Unit performance curves are also provided in these figures for comparison. These curves are often used as representative of average CO_2 flood performance and are taken from the Shell CO_2 flood scoping spreadsheet model.[7,8]

In addition to differences in the predicted ultimate tertiary oil recovery, the timing of the initial predicted tertiary response is also affected by the reservoir heterogeneity. **Figure 6** compares differences in the initial CO_2 production for the different permeability models. **Figure 7** compares differences in the initial oil production. The predicted oil and CO_2 production are earlier as the heterogeneity increases.

If there is no CO_2 flood production history to match, a wide potential variation in predicted tertiary CO_2 flood oil recovery is possible even though the waterflood history was matched. ***An excellent waterflood match does not guarantee a correct CO_2 flood forecast largely because the match is independent of the appropriate level of heterogeneity required for the CO_2 flood forecast***. The waterflood match can, however, generate a false belief in a calibrated model and a false sense of confidence in the CO_2 flood forecast

CO_2 Flood Match and Tertiary Forecast

The objective of the revised simulation study was to provide improved forecasts of oil and CO_2 production. A requirement and first step in the new forecast was matching the historical CO_2 flood oil and CO_2 production data for the simulated area. A key factor for the present study was that actual CO_2 flood response data was available.

The strategy for doing the CO_2 flood history match was to select the geostatistical case whose forecast was closest to the actual CO_2 flood production data with the base gas relative permeability curve and then improve the match by adjusting the gas relative permeability curve to better match oil and CO_2 production data. The crucial factor to match was the ***timing of CO_2 breakthrough***. The anticipated range for the maximum endpoint gas relative permeability was about 0.1 to 0.2. (See section on CO_2 and gas relative permeability.)

The original grid proved to be inadequate because the predicted CO_2 flood response with the base gas curve was too delayed. Increasing the gas relative permeability to acceptable levels did not result in a match. This inability to match the initial CO_2 flood response indicates that the original grid did not have sufficient heterogeneity and validated the decision to create new geostatistical grid models. Case 3 and Case 4 were also excluded, but for the opposite reason. Too early a CO_2 flood response was predicted. Extremely small values for the maximum gas relative permeability would be required to delay the predicted response to match the timing of the actual response. Case 3 and Case 4 had too much effective heterogeneity.

Case 1 and Case 2 were both found to give results close to the actual CO_2 flood production data with the base gas relative permeability curve. The base gas relative permeability curve used in the current simulation study had a maximum value of 0.125. For Case 1, a delay was needed, and a decrease of the maximum gas relative permeability to 0.09 was found to best match the actual production data. An earlier response and an increase of the maximum gas relative permeability to 0.2 was found to give the best match for Case 2. **Figure 8** shows the match of the CO_2 production for these two cases, and **Figure 9** shows the match of the oil production. The objective was to achieve a very good match to the actual CO_2 flood data, and this objective could be achieved for these two cases, and additional geostatistical grids were not created.

Adjusting the gas relative permeability curves to match the initial CO_2 flood production data brought the ultimate tertiary oil and CO_2 production forecasts for Cases 1 and 2 much closer. *Adjusting the gas relative permeability curve could compensate for moderate differences in the reservoir heterogeneity.* **However, adjusting the gas curve is not a perfect process and can not compensate for large errors in the reservoir heterogeneity.**

CO_2 and Gas Relative Permeability: In order to most accurately simulate all phases of recovery for a field in which a CO_2 flood is conducted, two gas curves may be needed. Two curves were used for the this study. The gas curve from the standard gas-oil relative permeability tests (with moderate adjustments) was used for the primary production and the waterflood phases, while a gas curve which represents CO_2 relative permeability was used during the CO_2 flood phase. A base gas relative permeability curve with a maximum value of 0.125 was used for the CO_2 flood while a curve with a larger endpoint value was used for primary production. Measurements of CO_2 relative permeability are typically not done. Some measurements of endpoint values of CO_2 relative permeability have been done. Such tests have been done by Texaco as well as by a few other companies. The results have typically shown that CO_2 relative permeability tends to be smaller than the gas permeability measured in standard gas-oil relative permeability tests and that the maximum CO_2 relative permeability is about a factor of five to ten smaller than the maximum oil relative permeability.[2,3,4] A gas curve with a maximum endpoint relative permeability of about 0.1 to 0.2 is suggested by these studies.

Conclusions

1. Waterflood history matches are not unique. By adjusting the water-oil relative permeability curves appropriately, a given oil and water production history can be matched using different permeability grids with different amounts of variation.

2. The subsequent tertiary CO_2 flood forecasts for these grids can be very different and have substantial errors. An excellent waterflood match does not guarantee a correct CO_2 flood forecast because adjustment of the water-oil relative permeability curves no longer compensates for different reservoir heterogeneities in the CO_2 flood as it did for the waterflood. The permeability grid must have the correct amount of permeability variation for the CO_2 flood forecast to be accurate.

3. The original grid from a previous simulation study was found to have insufficient heterogeneity. It could not be used to effectively match the initial CO_2 flood response. Four new geostatistical grid models with varied, but greater, levels of heterogeneity were created for a revised simulation study. Additional models would have been created, if needed.

4. Matching actual CO_2 flood response was a key factor in the selection of a grid with an appropriate level of heterogeneity.

5. The predicted CO_2 flood production response was initially fairly close to the actual for two of the grid models. The match was improved further with adjustments of the gas relative permeability curve. Matches for the original grid and the other geostatistical grids could not be done or required extreme gas curve adjustment. Adjustments in the gas curve can not be expected to compensate for large errors in reservoir heterogeneity.

6. Even though the two cases which could be used for the CO_2 flood history match initially predicted different ultimate tertiary recoveries when the same gas relative permeability curve was used, adjusting the gas relative permeability curves to match the initial CO_2 flood production data brought the subsequent tertiary oil and CO_2 production forecasts for both cases much closer. Adjusting the gas curve for the CO_2 flood can compensate for moderate errors in the reservoir heterogeneity just as adjusting the water-oil curves can similarly compensate for heterogeneity errors in a waterflood match or forecast.

7. Matching actual CO_2 flood response data permitted the generation of CO_2 flood forecasts with much less variability and much greater confidence.

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Table 1 - Correlation Lengths for Geostatistical Cases

Case	Major Correlation ft	Minor Correlation ft	Vertical Correlation ft	Apparent Heterogeneity
1	2000	700	1.5	Intermediate
2	3000	2000	2	Least
3	6000	3000	1.5	Greatest
4	8000	6000	1.6	Greatest

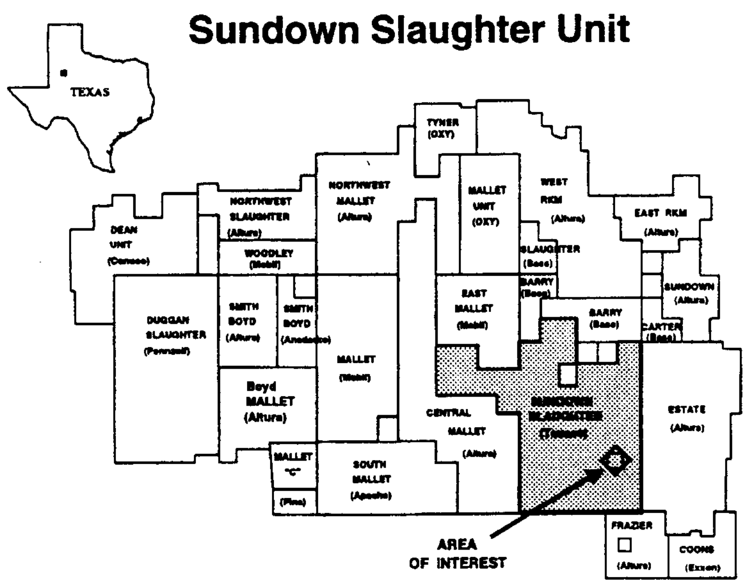

Figure 1 - Sundown Slaughter Unit Location

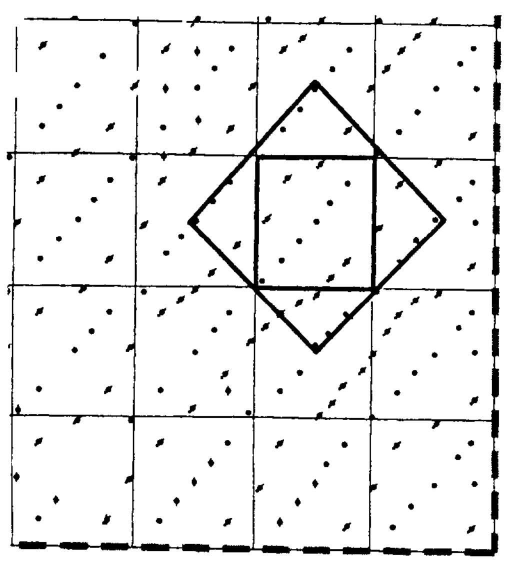

Figure 2 - Simulation Area

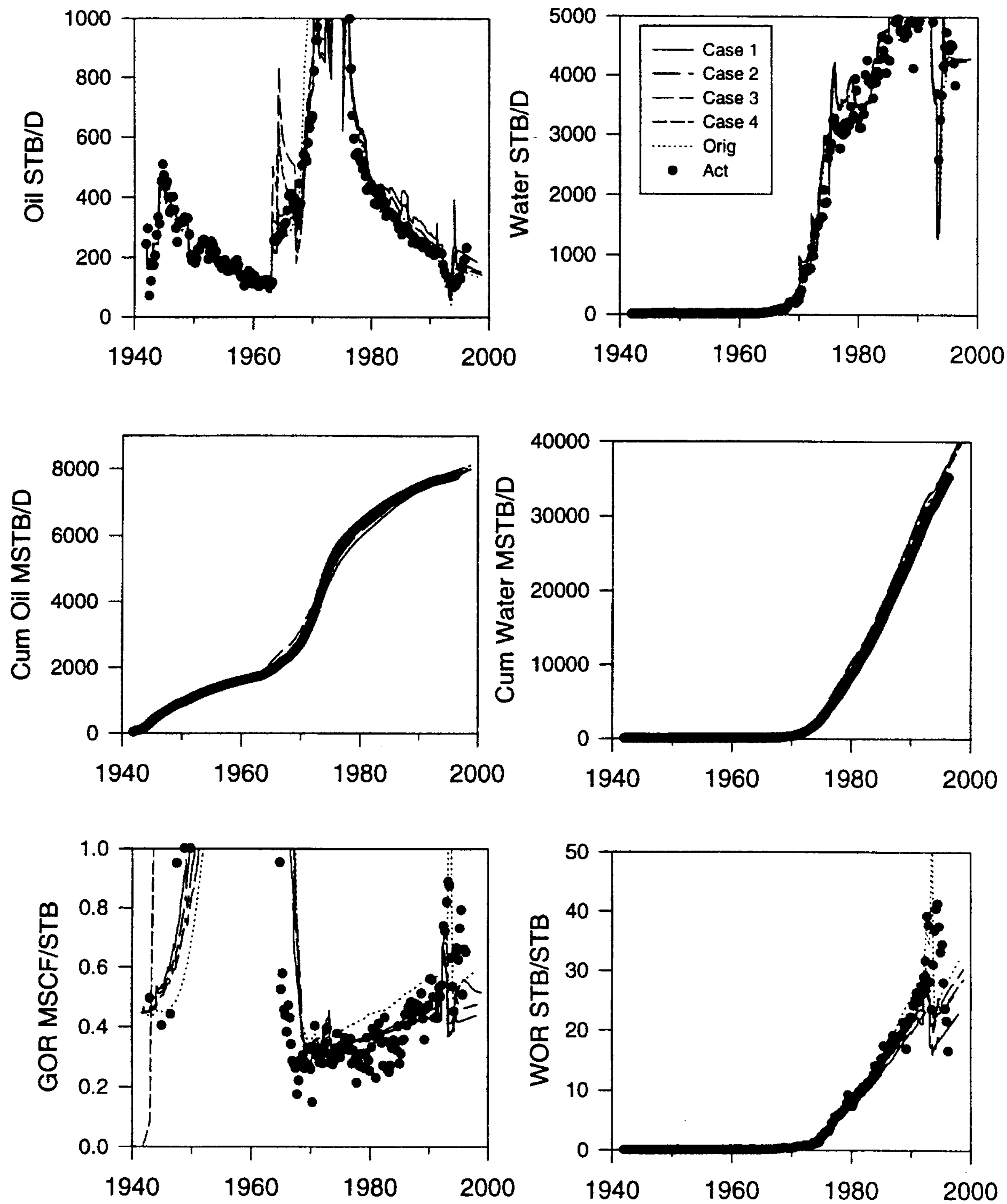

Figure 3 - Waterflood History Matches for Different Permeability Grid Cases

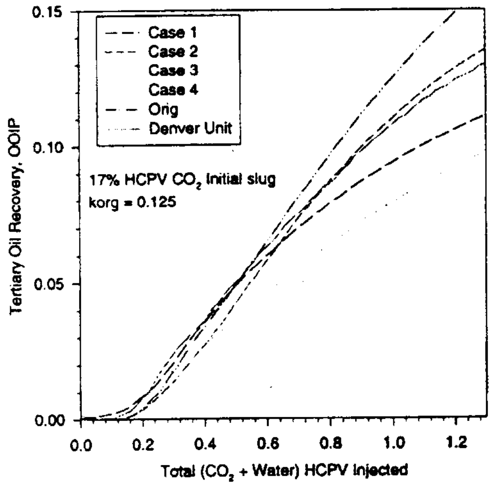

Figure 4 - Dimensionless CO_2 Flood Tertiary Oil Recovery Forecasts for Different Permeability Grid Cases (using the same gas relative permeability)

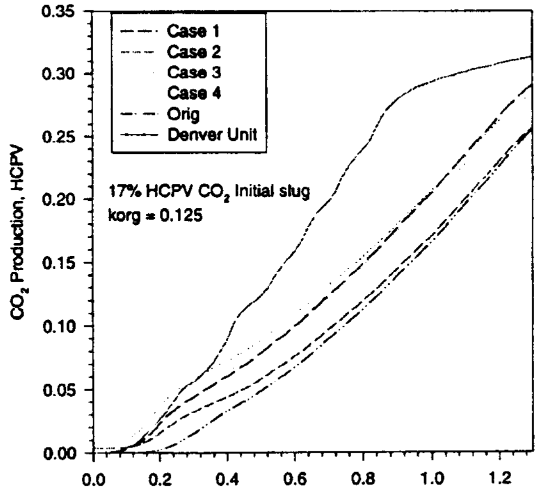

Figure 5 - Dimensionless CO_2 Production Forecasts for Different Permeability Grid Cases (using the same gas relative permeability)

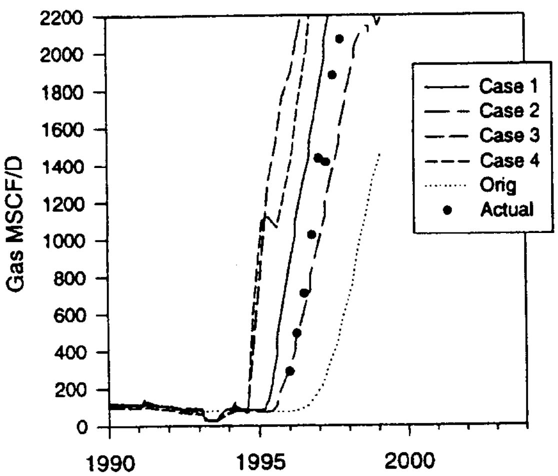

Figure 6 - Variation in Predicted Initial CO_2 Production

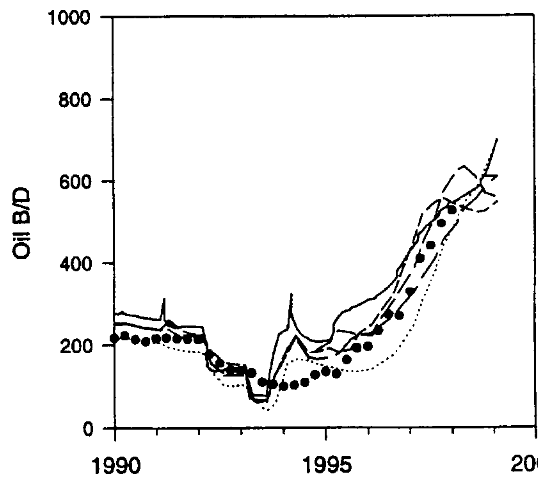

Figure 7 - Variation in Predicted Initial CO_2 Flood Oil Production

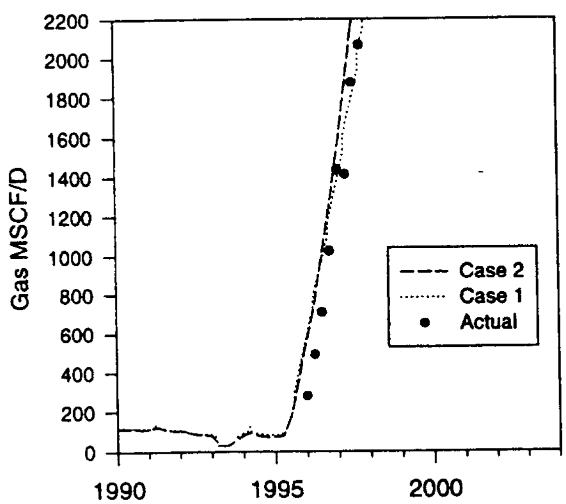

Figure 8 - History Matches of Actual CO_2 Production

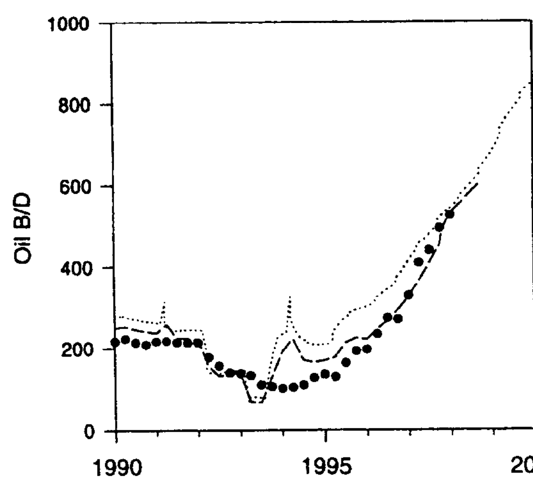

Figure 9 - History Matches of Actual CO_2 Flood Oil Production