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Semi-Annual Technical Progress Report

PREFERRED WATERFLOOD MANAGEMENT PRACTICES FOR THE SPRABERRY TREND AREA

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Harold Vance Department of Petroleum Engineering
Texas A& M University
3116 TAMU
College Station, TX 77843-3116
(979) 845-2241

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Program Manager:	C. M. Sizemore Pioneer Natural Resources
Principal Investigator:	David S. Schechter Harold Vance Department of Petroleum Engineering
Contracting Officer's Representative:	Dan Ferguson National Petroleum Technology Office
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ABSTRACT

This report describes the work performed during the first semi-annual third year of the project, “Preferred Waterflood Management Practices for the Spraberry Trend Area.”

The objective of this project is to significantly increase field-wide production in the Spraberry Trend in a short time frame through the application of preferred practices for managing and optimizing water injection. Our goal is to dispel negative attitudes and lack of confidence in water injection and to document the methodology and results for public dissemination to motivate waterflood expansion in the Spraberry Trend. To achieve this objective, in this period we concentrated our effort on analyzing production and injection data to optimize the reservoir management strategies for Germania Spraberry Unit. This study address the reservoir characterization and monitoring of the waterflooding project and propose alternatives of development of the current and future conditions of the reservoir to improve field performance.

This research should serve as a guide for future work in reservoir simulation and can be used to evaluate various scenarios for additional development as well as to optimize the operating practices in the field.

The results indicate that under the current conditions, a total of 1.410 million barrels of oil can be produced in the next 20 years through the 64 active wells and suggest that the unit can be successfully flooded with the current injection rate of 1600 BWPD and the pattern consisting of 6 injection wells aligned about 36 degrees respect to the major fracture orientation.

In addition, a progress report on GSU waterflood pilot is reported for this period.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

Evaluation of Waterflooding Performance in Germania Spraberry Unit

Germania Spraberry Field Demonstration Status

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This support is gratefully acknowledged, as well as that of Oil Filed Manager (OFM), which donated software used in this study. I greatly appreciate diligent efforts from the following individuals who contributed to this project: Erwin Hernandez conducted evalution of waterflooding in Germania unit as described in Chapter 1 and Erwinsyah Putra wrote field demonstration status as described in Chapter 2.

EXECUTIVE SUMMARY

This report describes the work performed during the first semi-annual of the third year of the project, “Preferred Waterflood Management Practices for the Spraberry Trend Area.” The objective of this project is to significantly increase field-wide production in the Spraberry Trend in a short time frame through the application of preferred practices for managing and optimizing water injection. Our goal is to dispel negative attitudes and lack of confidence in water injection and to document the methodology and results for public dissemination to motivate waterflood expansion in the Spraberry Trend.

This report provides results of the fifth semi-annual technical progress report that consists of analyzing production and injection data to optimize the reservoir management strategies for Germania Spraberry Unit and an update on GSU waterflood pilot. Within the project objective, the specific goals for this period are to (1) integrate the production and injection data to characterize the reservoir, (2) evaluate development opportunities with emphasis toward preventing trapped oil, and maximizing recovery, (3) identify bypassed oil and flood front to locate infill wells, (4) identify problems in some wells by using the concept of water-oil ratio and its derivative to differentiate whether the wells are experiencing coning problems, layer breakthrough or near wellbore channeling, (5) estimate the remaining reserves associated to the drainage radius of every well by performing decline curve analysis of individual wells, and (6) analyze the historical relationship between reservoir withdrawals and the water injection rate in different areas of the unit to optimize the performance of the waterflood.
In this report we present the following work that has been performed to achieve the aforementioned goals. The following headings and subsequent findings outline the work that appears in this report.

Evaluation of Waterflooding Performance in Germania Spraberry Unit. The Germania unit as well as other units in the Spraberry Area has been waterflooded using the conventional waterflood techniques applied in natural fractured reservoirs, where all injection wells are aligned parallel along major fracture trend to force the oil to flow perpendicular to the fracture trend towards a line of producer wells.
In the past, several studies have been conducted to propose different waterflooding techniques and development plans for Germania Unit; however none of the previous studies, have addressed the reservoir characterization and monitoring of the waterflooding project and propose alternatives of development taking into account the current and future conditions of the reservoir.
Consequently, this project will be addressed to provide a significant reservoir characterization and evaluate the performance of the waterflooding to provide facts, information and knowledge to obtain the maximum economic recovery from this reservoir. Thus, attempts are made to describe the reservoir, understand the performance of the reservoir under the current waterflooding project, and controlled surveillance will be carried out to improve field performance. The following methodology was used to achieve the objectives of the project:

1. The data needed was collected, reviewed, and validated and data base constructed using the software Oil Field Manager (OFM). Since the data was obtained from

different related sources, it was reviewed, re-organized, and finally reduced to a format manageable in OFM. The data collected comprises: production and injection, coordinates, dates and events, wellbore, limits of leasing, logs, PVT analyses, etc. The calculations and processes were done using the main modules of the program (Decline Curve Analysis, System Functions, Calculated Variables, Plots, Reports, Bubble Maps, Grid Maps and Scatter Plots) and the interrelation among them, was also considered.

2. The study was approached by considering the overall performance of the Germania Unit as well as the performance and experiences obtained in others areas of Spraberry Unit. Under a full field scope surveillance system, the different modules of OFM were used and statistical analyses for different wells were also considered.
3. Based on this study, recommendations for future field operation and developing plan were provided.

Germania Spraberry Field Demostration Status. In our previous results, we forecasted the incremental oil recovery due to waterflood in other pilot area, which was applied to the Germania Spraberry Unit (GSU,) and requested management approval of this project. The project was approved and we proposed the new location of injectors based on the existing injectors' location and response of previous injectors to producers. We also identified the wells that have casing leaks using OFM based on the plot of water-oil ratio. We observed the response of water injection through each of production wells and the group of the wells in each track. We analyzed the production and injection data through production database management using Oil Field Manager (OFM) and Field Management Database Software (FMDS).

In this period, we continue to observe the response of water injection through each of production wells and the group of the wells in each track. We found that the current amount of water injection rate is not enough to support the current production rates based on response of new production wells and VRR analysis. The effect of water injection still has not reached many wells in Tracts 1 and 3. There may be the water is still in the filling up process. We may need to wait a longer time to see the waterflood response.

Project Fact Sheet

Progress work efforts at Project Fact Sheet are listed in Appendix A.

I. Evaluation of Waterflooding Performance in Germania Spraberry Unit

I. Introduction

The Germania Unit is located in Midland County, 12 miles east of Midland, Texas (Fig.1.1) and covers and area of approximately 4900 acres. It is part of the Spraberry Formation in the Midland Basin which is one of the largest known oil reservoirs in the world bearing between 8.9 billion barrels (Handford, 1981) and 10.5 billion barrels (Guevara, 1988) of oil originally in place (OOIP). Of this, 740 million barrels have been produced since its discovery in 1949. The Spraberry formation has been affected by postdepositional tectonic activity creating a network of secondary porosity. The field is considered geologically complex since it comprises typically low porosity, low permeability fine sandstones and siltstones that are interbedded with shaly non-reservoir rocks and natural fractures existing over a regional area that have long been known to dominate all aspects of performance in the Spraberry Trend Area.

Germania Unit has been waterflooded using the conventional techniques applied in naturally fractured reservoirs in the Spraberry area, where all injection wells were aligned parallel along the major fracture trend to force the oil to flow towards a line of production wells. Many wells have been abandoned in The Germania Unit as a result of either casing failures or low productivity. In this area , conventional waterflooding techniques have often led to economic failures in the attempt to recover additional oil, because the injected water tends to channel through the high permeability fracture system leaving the rock matrix, where the additional oil resides , virtually unaffected by the waterflood process, and thus understanding the mechanics and interaction between the fracture system, matrix, wells and the past performance of the waterflooding may lead to more effective oil production and therefore to a significant increasing in the recovery factor.

Germania Unit was discovered in 1957. During the first 8 years under primary recovery, the reservoir was poorly developed due to low well productivity and well spacing. During this primary stage, the unit produced under solution gas drive. The total cumulative oil production corresponding to this period was 0.55 million barrels of oil at an average oil rate of 188 BOPD. In 1965 a waterflooding program was initiated and continued until 1990. The purpose of this waterflooding program was to improve the recovery by sweeping the oil from the injectors located in the middle part of the structure, towards the producers located throughout the reservoir. The water was injected through 5 wells located in different positions of the reservoir. The cumulative water injected under this period was 2.44 million barrels and the cumulative water production was 0.95 million barrels. In May 1990 the water injection was suspended when the average water cut in the producer wells increased up to 0.75, two infill drilling campaign took place increasing the numbers of producer wells from 20 to 98 in a period of 10 years and increasing the number of active wells up to 66 .Oil production reached its maximum peak at 956 BOPD in 1992. The reservoir continued producing under this condition (water injection equal to zero) from 1990 to 2002. The cumulative oil production and injection as of June 2003 were 2.24 million barrels and 2.44 million barrels respectively. In February 2003 the operator began a new water injection project (under a new injection pattern) from six injector wells by converting three wells to water injectors, returning two wells to water injectors and drilling a new injector well (**Fig.1.2**). Each one of the six injector wells is injecting 270 BWPD. Since this program was initiated, some producers have shown favorable response to the injection (they have increased the oil rate respect to the rate they had before the new injection process took place). Currently the production level is 470 BOPD through 64 active wells and the cumulative oil production is 2.242 million barrels.

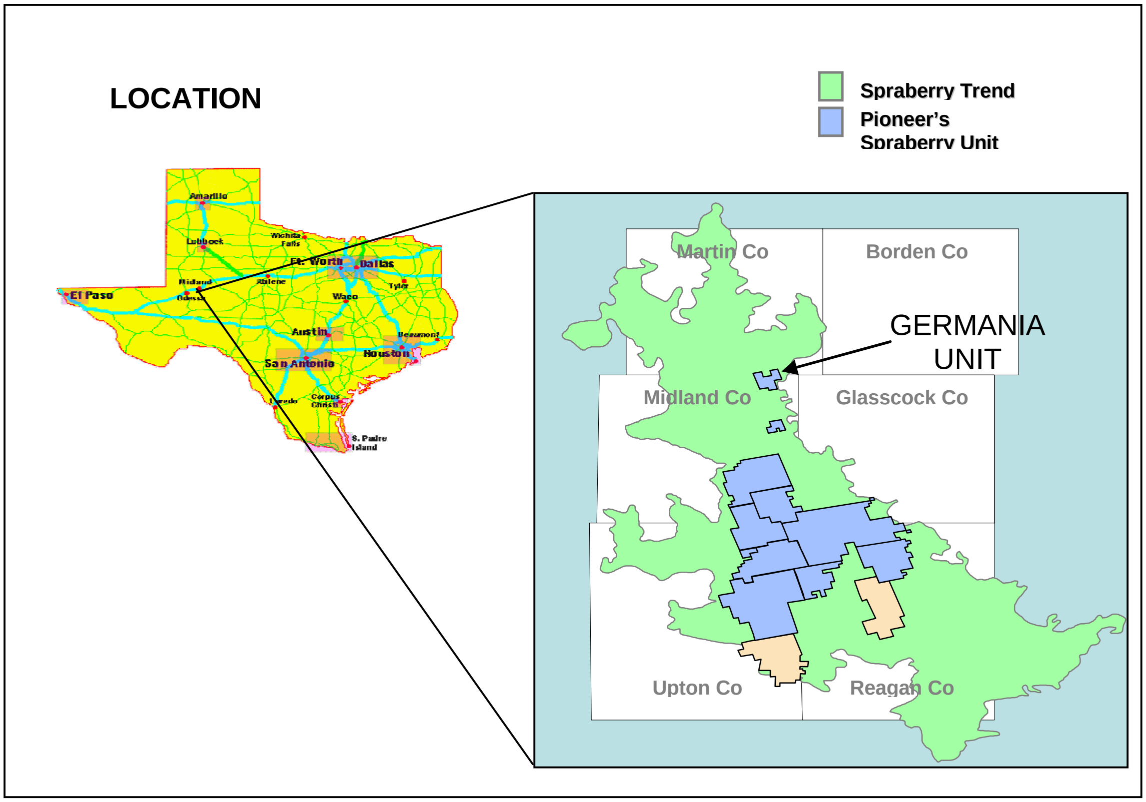

Fig.1. 1– Location of Germania Spraberry Unit.

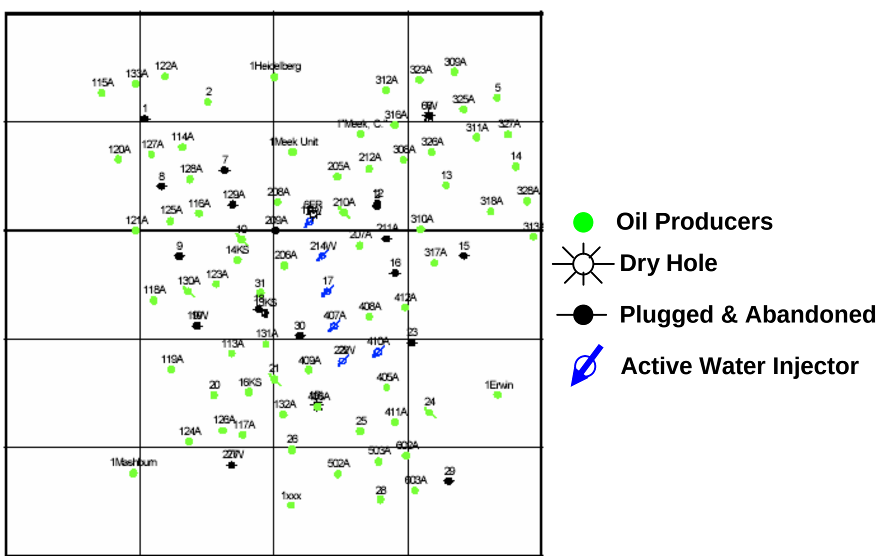

Fig.1. 2– Location of New Water Injectors Wells in Germania Spraberry Unit.

1.1. Description of the Problem

The Germania unit as well as other units in the Spraberry Area has been waterflooded using the conventional waterflood techniques applied in natural fractured reservoirs, where all injection wells are aligned parallel along major fracture trend to force the oil to flow perpendicular to the fracture trend towards a line of producer wells.

In the past, several studies have been conducted to propose different waterflooding techniques and development plans for Germania Unit; however none of the previous studies, have addressed the reservoir characterization and monitoring of the waterflooding project and propose alternatives of development taking into account the current and future conditions of the reservoir.

Consequently, this project will be addressed to provide a significant reservoir characterization and evaluate the performance of the waterflooding to provide facts, information and knowledge to obtain the maximum economic recovery from this reservoir. Thus, attempts are made to describe the reservoir, understand the performance of the reservoir under the current waterflooding project, and controlled surveillance will be carried out to improve field performance.

1.2 Objectives of the Research

The main objectives of this study are:

1. Integrate the production and injection data to characterize the reservoir. During the primary and secondary performance, wells indicating high cumulative production may indicate high permeability zone and porosity. On the other hand , wells with relative low cumulative production may indicate very low permeability and porosity or poor mechanical condition , skin damage , or isolated pay intervals.
2. Evaluate development opportunities with emphasis toward preventing trapped oil, and maximizing recovery. These development opportunities may comprise perforating additional intervals in some wells.
3. Identify bypassed oil and flood front to locate infill wells and look for further development opportunities by selecting areas with high oil saturation remaining and showing in pictorial displays the location of various flood fronts showing visual

differentiation between areas of the reservoir that have and have not been swept by the water.

4. Provide possible fracture orientation and its effect on the production based on past performance of the waterflood. The analysis of the on-trend and off-trend well production will help to support the theory of northeast-southwest trend. The on-trend and off-trend wells will be chosen based on their location with regards to the injectors.
5. Identify problems in some wells by using the concept of water-oil ratio and its derivative to differentiate whether the wells are experiencing coning problems, layer breakthrough or near wellbore channeling.
6. Estimate the remaining reserves associated to the drainage radius of every well by performing decline curve analysis of individual wells completed in the reservoir. Present the results in pictorial displays showing the areas of the reservoir with the most remaining reserves. In this stage different scenarios will be analyzed to forecast the reserves and make extrapolations in the future to evaluate the benefits of waterflooding in Germania Unit area and predict the future performance of the field under different producing and injection schemes.
7. Analyze the historical relationship between reservoir withdrawals and the water injection rate in different areas of the unit to optimize the performance of the waterflood.

1.3 Research Methodology

The following methodology was used to achieve the objectives of the project:

1. The data needed was collected, reviewed, and validated and data base constructed using the software Oil Field Manager (OFM), which is a powerful surveillance software application that provides an array of modules and tools for managing and analyzing static and dynamic data. Since the data was obtained from different related sources, it was reviewed, re-organized, and finally reduced to a format manageable in OFM. The data collected comprises: production and injection, coordinates, dates and events, wellbore, limits of leasing, logs, PVT analyses, etc. The calculations and

processes were done using the main modules of the program (Decline Curve Analysis, System Functions, Calculated Variables, Plots, Reports, Bubble Maps, Grid Maps and Scatter Plots) and the interrelation among them, was also considered.

2. The study was approached by considering the overall performance of the Germania Unit as well as the performance and experiences obtained in others areas of Spraberry Unit. Under a full field scope surveillance system, the different modules of OFM were used and statistical analyses for different wells were also considered.
3. The final step in this waterflooding surveillance and reservoir characterization study was reporting the results achieved, derived conclusions, as wells as recommendation for future field operation and developing plan.

II. Reservoir Performance

2.1 Primary Performance in Germania Spraberry Unit

The Germania Spraberry Unit is located in Midland county, 12 miles east of Midland, Texas and began its primary production in 1957. After the discovery, the unit was developed in a 160 acre-spacing and by the end of this stage (primary performance) in 1965 a total of 11 wells were drilled and some of them temporarily abandoned or shut-in due to different reasons (low productivity, high water cut, and casing failures). The total cumulative oil production corresponding to this period was 0.55 million barrels of oil at an average oil rate of 188 BOPD and the production reached a maximum peak of 480 BOPD in 1961 and the water cut by the end of the stage averaged 20 percent (**Fig.2.1**). The production of liquid per well averaged 37 BLPD and the average production of oil per day per well was 37 BOPD (**Fig.2.2**). The oil produced during this stage (0.55 million barrels) represents only 1.7 percent of the total produced by the unit (Germania Spraberry) as of June 2002.

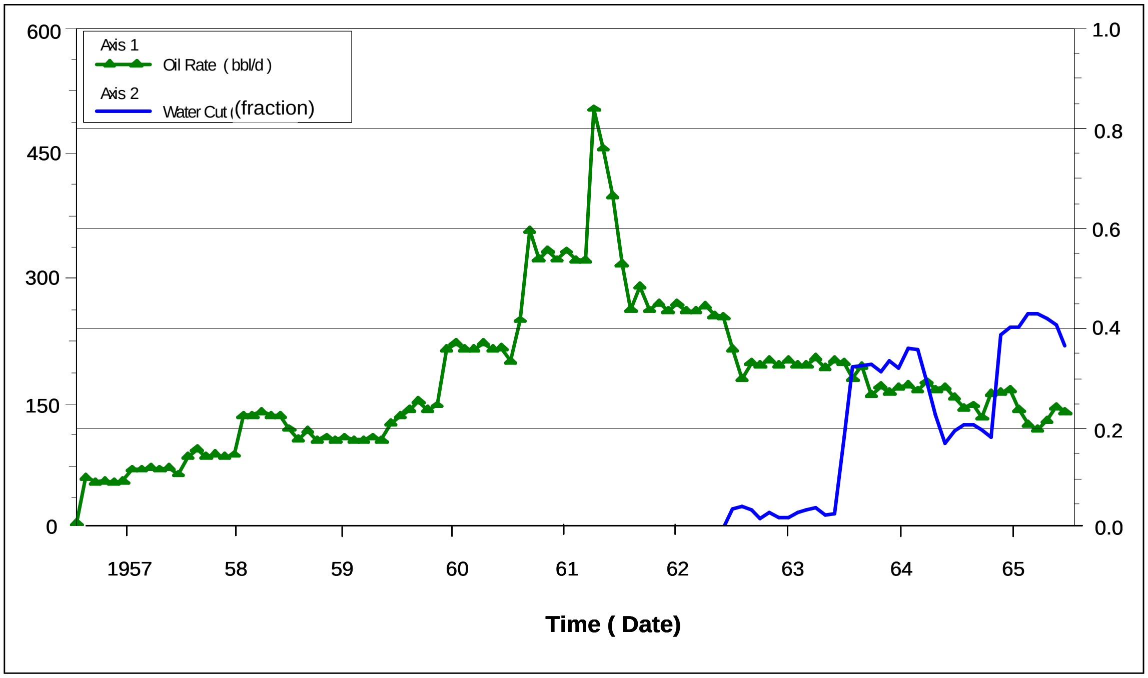

Fig. 2.1-Oil Rate and Water Cut during Primary Depletion of Germania Spraberry Unit.

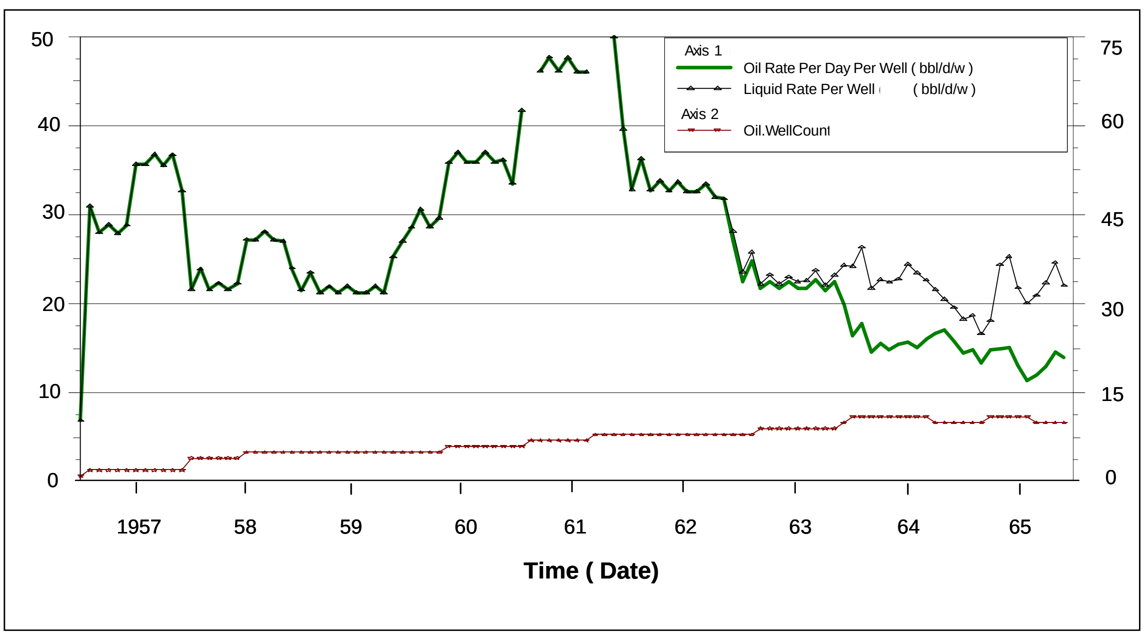

Fig. 2.2-Oil Rate per well, Liquid Rate per well and Active wells during Primary Depletion for Germania Spraberry Unit.

2.2 Secondary Performance in Germania Spraberry Unit (Waterflooding).

In 1965 a waterflooding program was initiated and continued until 1990. The purpose of this waterflooding program was to improve the recovery by sweeping the oil from the injectors located in the middle part of the structure towards the producers located throughout the reservoir. The water was injected through 5 wells (wells: 11W, 19W, 22W, 17W, and 6W) located in different positions of the reservoir (**Fig.2.3**). The cumulative water injection under this period was 2.44 million barrels, the average water injection rate per well was 688 BWPD (**Fig.2.4**), and the cumulative water production was 0.95 million barrels of oil.

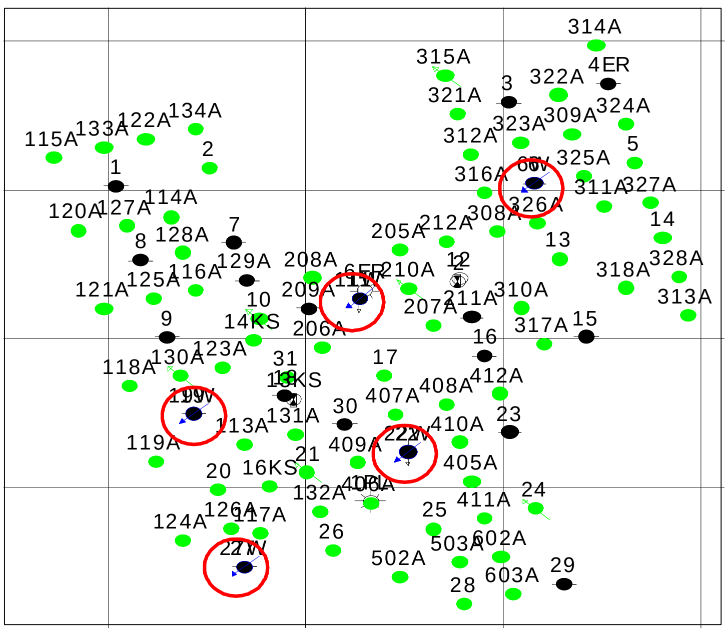

Fig.2. 3 -Base Map of Germania Spraberry Unit showing the wells injecting water from 1965 to 1990.

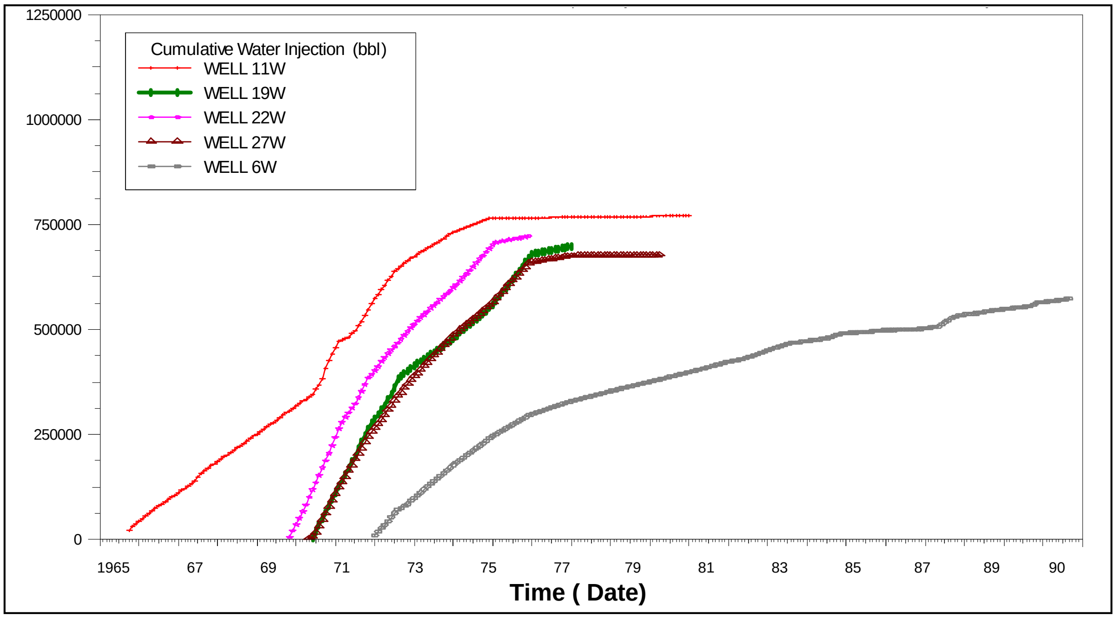

Fig.2. 4 -Cumulative Water Injection for the five wells injecting from 1965 to 1990.

In May 1990 the water injection was suspended when the average water cut in the producer wells increased up to 0.75, two infill drilling campaign took place increasing the numbers of producer wells from 20 to 98 in a period of 10 years, increasing the number of active wells up to 66 and developing the reservoir under a 40 acre-spacing. Oil production rate reached its maximum peak at 956 BOPD in 1992. The reservoir continued producing under this condition (water injection equal to zero) from 1990 to 2002 (**Fig.2.5**).

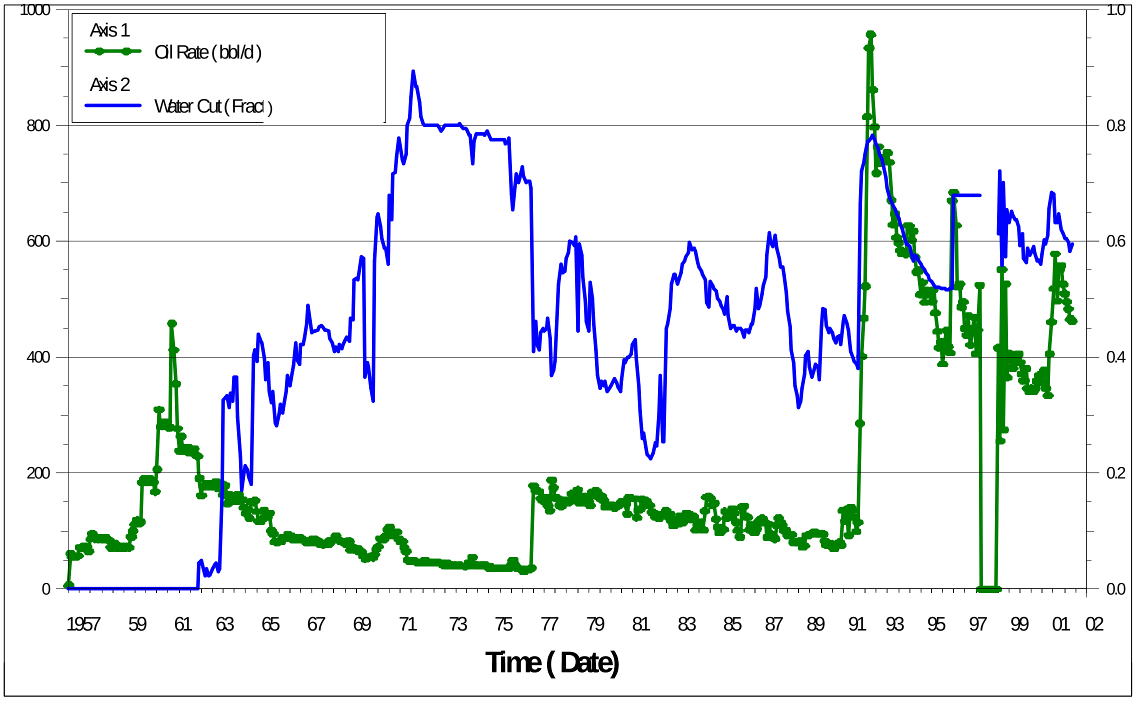

Fig.2. 5-Oil Rate and Water Cut during Primary and Secondary Depletion of Germania Spraberry Unit.

The cumulative water production and injection as of June 2003 were 2.24 and 2.44 million barrels respectively. In February 2003 the operator began a new water injection project (under a new injection pattern) through six injector wells by converting three wells to water injectors, returning two wells to injectors and drilling a new injector well (**Fig.2.6**). Each one of the six injectors is currently injecting 270 BWPD. Since this program was initiated, some producers have shown favorable response to the injection. Currently the production rate is 470 BOPD through 64 active wells and the cumulative oil production is 2.242 million barrels. During the secondary performance the average oil production per well was 12 BOPD, average liquid production per well was 40 BLPD, and the numbers of active wells was increased significantly by infill drilling and controlling the operations in the field (**Fig.2.7**).

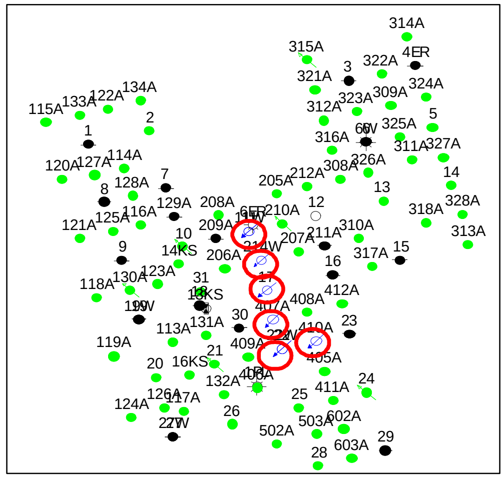

Fig.2. 6 -Base Map of Germania Spraberry Unit showing wells injecting water under the new Injection Pattern

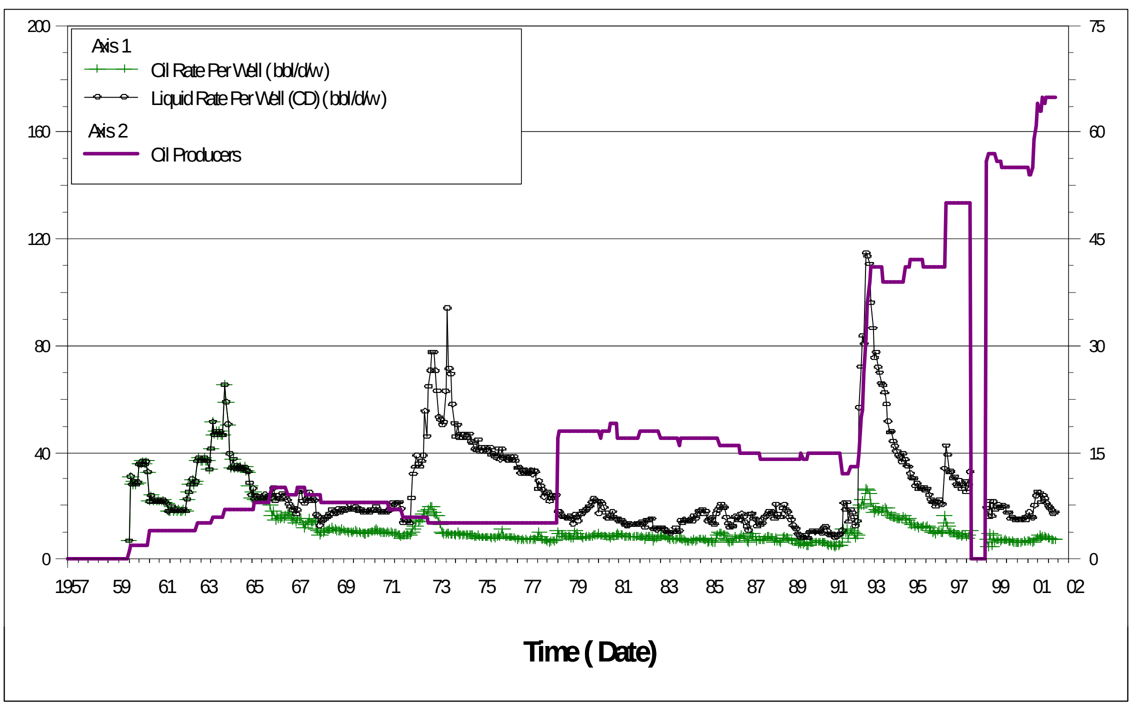

Fig.2. 7-Oil Rate per well, Liquid Rate per well and Active wells during Primary and Secondary Depletion for Germania Spraberry Unit.

III. Reservoir Monitoring and Surveillance System

This chapter describes a reservoir management approach to waterflood Surveillance in Germania Spraberry Unit considering interrelated parts of the system. The primary function of this surveillance system is to provide facts, information, and knowledge necessary to control operations in the field and maximize the recovery from the unit.

Sometimes the actual performance of most fields may not agree with the expected performance of it. In the case of Germania Spraberry Unit, the differences between its performance and the performance of others units in Spraberry may be due to inadequate geological description, well completion problems, etc. The reasons for its low productivity and disappointing waterflood performance have remained unexplained until now. Various hypotheses have been proposed to explain the poor performance of the unit. These hypotheses include: lack of pattern confinement and injection well density, poor waterflood pattern development, complex fracture networks, fracture mineralization, wettability effects, lack of understanding of the imbibition transfer mechanism and stress-sensitive permeability.

In this chapter we have tried to identify the key parameters that have significant effect on the actual waterflood performance and some possible explanations of this behavior , and recommendations to improve the performance of the unit. Thus, attempts would be made to monitor the performance of the field and improve its recovery.

For this, we developed a data base using the software Oil Filed Manager (OFM) which is a powerful surveillance software application that provides an array of modules and tools for managing and analyzing static and dynamic data. Since the data was obtained from different related sources, it was reviewed, re-organized, and finally reduced to a format manageable in OFM. The data collected comprises: production and injection for 103 wells, coordinates, dates and events, wellbore, limits of leasing, logs, PVT analyses, etc. The calculations and processes were performed using the main modules of the program (Decline Curve Analysis, System Functions, Calculated

Variables, Plots, Reports, Bubble Maps, Grid Maps and Scatter Plots) and the interrelation among them, was also considered.

3.1 Production Heterogeneity Indexing

In this part we describe a surveillance tool for production data referred to as Production Heterogeneity Index which quantifies and qualifies well performance anomalies for the purpose of assessing completion efficiency and determining the most successful practices in the unit as well as a surveillance tool for the waterflooding performance. The assessment of the Production Heterogeneity Index is also a valuable tool to production and reservoir engineers for selecting workover or stimulation candidates and determining the best completion practices in Germania Spraberry Unit in their efforts to improve the performance of the field. To properly apply the Production Heterogeneity Index and assure the validity of this analysis method, the following assumptions[3] were made:

- All wells being analyzed are completed and producing in the same formation (in some cases it is possible to obtain meaningful empirical correlations from commingled formations)
- The complete monthly well production history is available back to the beginning of life of each well.
- No artificial rates restrictions or constraints are placed on the wells being analyzed.
- All wells are producing with an equivalent type artificial lift system.
- All wells are producing under similar reservoir pressure conditions (It maybe possible to make corrections for large variations in reservoir pressure if pressure data is available for the wells in question).
- Sufficient numbers of wells area available to perform meaningful normalization of the data.

To estimate the Production Heterogeneity Index for the oil rate in every well, we applied the equation given by:

$$HI\ \ Oil\ \ Rate\ \ = \frac{Oil\ \ \ Rate}{Average\ \ \ \ OilRate} - 1 \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots. (3.1)$$

Where:

- $HI\ OilRate$ = Production Heterogeneity Index for the oil rate, Dimensionless.
- $Oil\ \ Rate$ = oil production rate for the well, BOPD
- $Average\ OilRate$ = average oil rate of all wells being analyzed, BOPD.

Similarly, we applied the Production Heterogeneity Index for the water rate. Given by the following equation:

$$HI\ \ Water\ \ \ Rate\ \ = \frac{Water\ \ \ \ Rate}{Average\ \ \ WaterRate} - 1 \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots.\ (3.2)$$

Where:

- $HI\ WaterRate$ = Production Heterogeneity Index for the water rate, Dimensionless.
- $Water\ \ Rate$ = water production rate for the well, BWPD.
- $Average\ WaterRate$ = average oil rate of all wells being analyzed, BWPD

For the case of Germania Spraberry Unit, we analyzed a total of 64 active wells (using the oil and water rate at the last date available in the database (June 2003)), by applying the equation (3.1) and equation (3.2) for every well.

According to the equation (3.1) wells showing Production Heterogeneity Index for the oil rate greater than zero have a current oil rate greater than the average oil rate of the reservoir (in this case Germania Spraberry Unit); whereas, wells with Heterogeneity Index for the oil rate less than zero have a current oil rate less than the average oil rate of the entire reservoir.

On the other hand, wells showing Production Heterogeneity Index for the water rate greater than zero mean they have a current water rate greater than the average water rate of the reservoir; whereas, wells with Heterogeneity Index for the water rate less than zero mean they have a current water rate less than the average oil rate. This is according to equation (3.2).

Combining the Production Heterogeneity Index for both rates oil and water, we can subdivide the wells into 4 different groups, as follows:

- Wells with Production Heterogeneity Index for both oil and water greater than zero (oil rate and water rate above the average).
- Wells with Production Heterogeneity Index for both oil and water less than zero (oil rate and water rate below the average).
- Wells with Production Heterogeneity Index for oil greater than zero and Production Heterogeneity Index for water less than zero (oil rate above the average and water rate below the average).
- Wells with Production Heterogeneity Index for oil less than zero and Production Heterogeneity Index for water greater than zero (oil rate below the average and water rate above the average).

Based on the four categories of wells mentioned above, we created the cross-plot in **Fig.3.1** showing the Production Heterogeneity Index for oil and water in 64 active wells of Germania Spraberry Unit. We can also plot the geographic location for each one of the wells analyzed (**Fig.3.2**) and study its behavior with respect to the position in the reservoir as well as its position with respect to injectors and the fracture orientation (**Fig.3.3**).

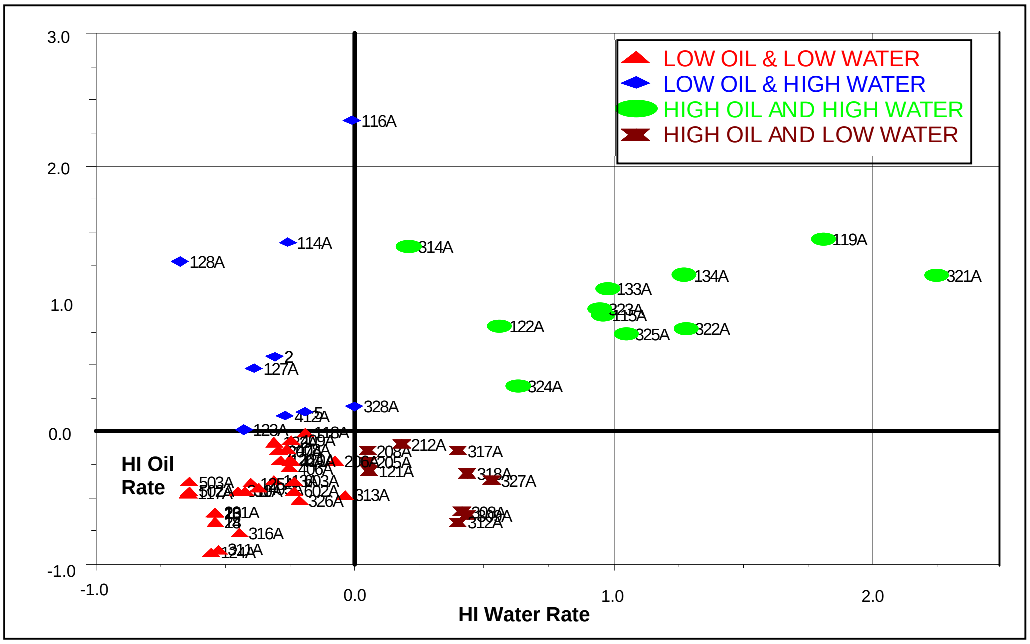

Fig.3. 1-Cross-Plot showing the Production Heterogeneity Index for Oil and Water in 64 active wells of Germania Spraberry Unit.

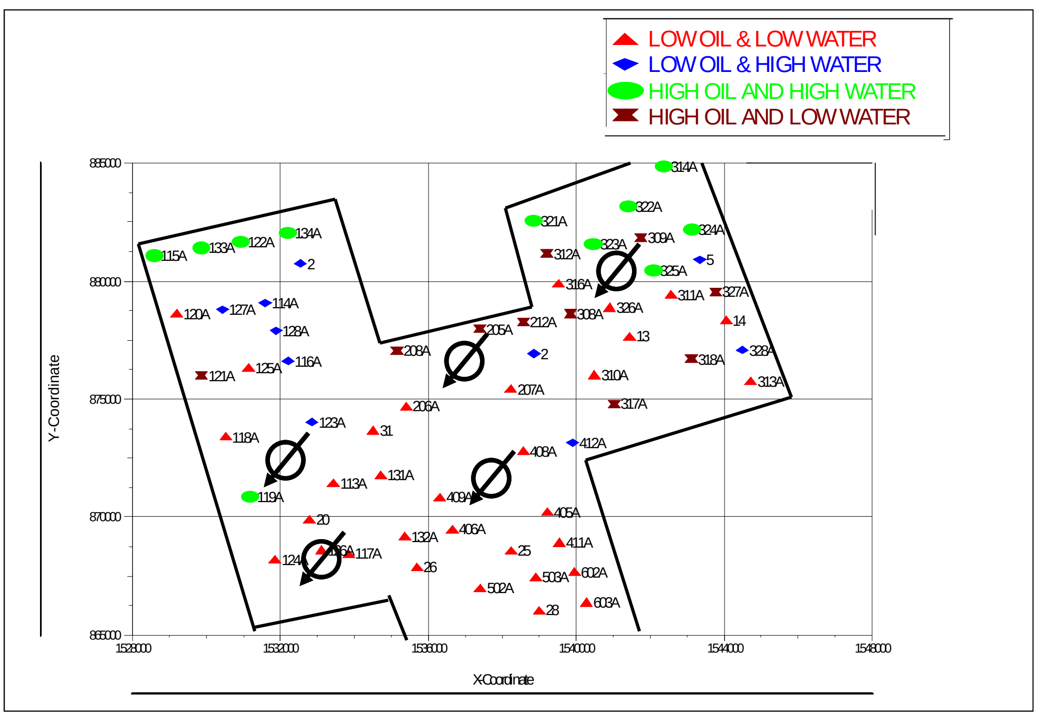

Fig.3. 2-Base Map showing the 64 Active Wells in Germania Spraberry Unit and its position with regards to the injectors (old injection pattern).

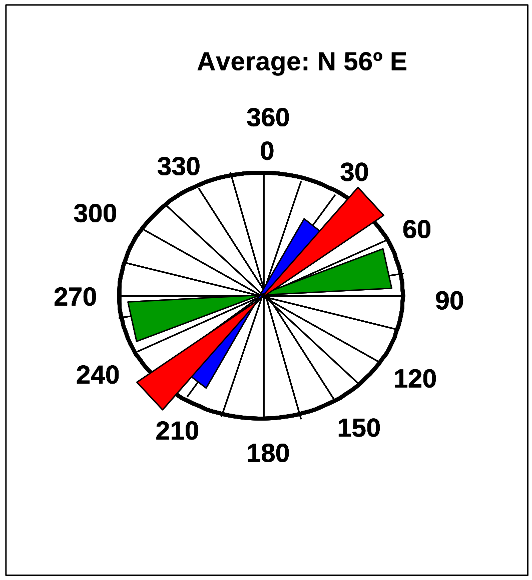

Fig.3. 3-Fracture Orientation from Core Analysis.

In general, the distribution of the different category of wells in the reservoir is an indication of the high degree of heterogeneity of the fracture system.

Wells with both water rate and oil rate below the average are distributed throughout the reservoir not following a trend; they represent good candidates for workover, stimulation or recompletion.

Wells with water rate below the average and oil rate above the average are located in a line forming a line oriented northeast-southeast which is in accordance with the major fracture orientation (this is also in agreement with the dominant tracer response observed in some wells in the area (in O'Daniel Spraberry Unit)).

Wells with both water rate and oil rate above the average, tends to follow a line with the same orientation of the major fracture trend. However, since they are located far away from the injectors, close to the upper limit of the lease, their behavior is probably affected by the operation and production taking place beyond the limits of Germania Spraberry Unit. Wells with water rate above the average and oil rate below the average clearly follow a line with an orientation parallel to the line of well injecting water (new injection pattern); those are wells candidates to conformance technology or remedial work to reduce the water rate. These results are summarized in **Table 3.1.**

Table 3. 1– Category of active wells based on the current Production Performance

CATEGORY	WELLS	Production Remarks	Location Remarks
High oil rate & High water Rate	115A,133A,122A,134A,119A,321A,314A,322A, 325A	Could be influenced by operations beyond the limits of Germania or by communication problems.	Located far away from the injectors.
High oil rate & Low Water rate	121A, 208A,205A,212A, 312A,308A,317A,309A,318A,327A	Good Producers	Follow the same direction of major fracture trend
Low oil rate & Low water rate	120A,125A,118A,206A,31,113A,131A,20,124A,126A,117A,132A,26,207A,409A,408A,406A,405A,25,411A,502A,503A,602A,28,603A,316A,326A,13,310A,311A,14,313A	Candidates for workover and /or stimulation	Scattered throughout the unit
Low oil rate & High water Rate	2,127A,114A,128A, 116A,123A,412A,328A,5	Candidates for Conformance control	Form a line parallel to the new injection pattern

3.2 Injection Withdrawal

This waterflood surveillance incorporates analyses of production/injection data for Germania Spraberry Unit to monitor the relationship between reservoir withdrawals and the water injection rate. This relationship was monitored by evaluating the Voidage Replacement Ratio (VRR) given by:

$$VRR = \frac{qWi}{q_O\ B_o + qW\ B_W + q_O(GOR - Rs)Bg} \quad \ldots\ldots\ldots\ldots\ldots (3.3)$$

Where:

VRR	=	Voidage Replacement Ratio, Dimensionless.
qWi	=	water injection rate, STB/D.
qo	=	oil production rate, STB/D.
Bo	=	oil formation volume factor, RB/STB.
qW	=	water production rate, STB/D.
B_w	=	water formation volume factor, RB/STB.
GOR	=	producing gas-oil ratio, scf/STB.
Rs	=	solution gas-oil ratio, scf/STB.
Bg	=	gas formation volume factor, RB/scf.

The Voidage Replacement Ratio (VRR) was analyzed during two different periods: from 1965 to 1989 (first injection period) and from January 2003 to August 2003 which correspond to the second injection period (under the new injection pattern). The first period exhibited an overall VRR greater than 1 suggesting that the volume being injected exceed the total volume being produced (**Fig.3.4**). From 1969 to 1975 the average value of VRR was 20, indicating that 20 barrels of water were injected per 1 barrel of fluid produced (oil, water, and gas). This may explain the high water cut and rapid breakthrough observed in some wells (especially those surrounding the injectors) and is perhaps one of the most responsible factors for the poor performance of the unit during this period. The second period exhibits an overall VRR of 1 (**Fig.3.5**), thus indicating that the water injection rate is matching the fluid production rate and therefore the water injection rate is optimum (currently 1600 BWPD), this also may indicate that the waterflooding project (under the new pattern of injection) is likely to be successful.

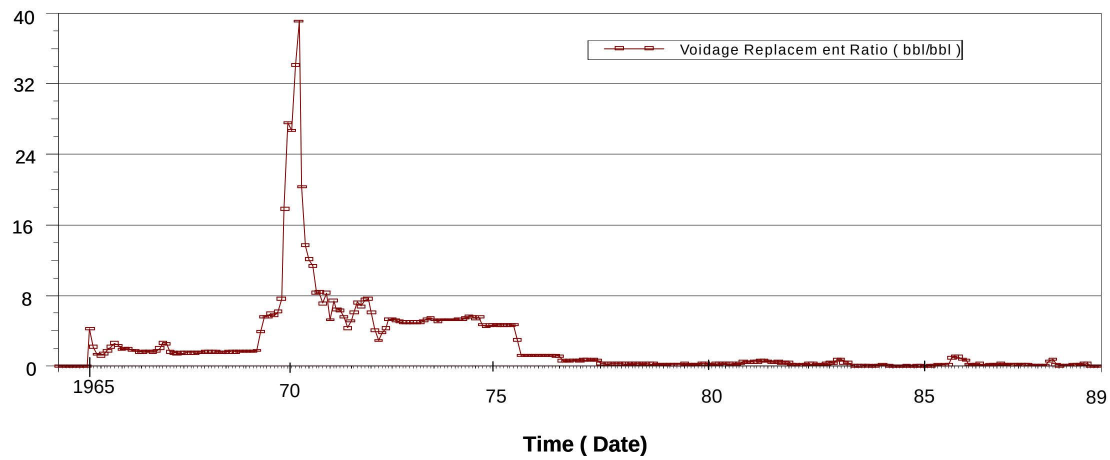

Fig.3. 4-Voidage Replacement Ratio for the First Period of Injection

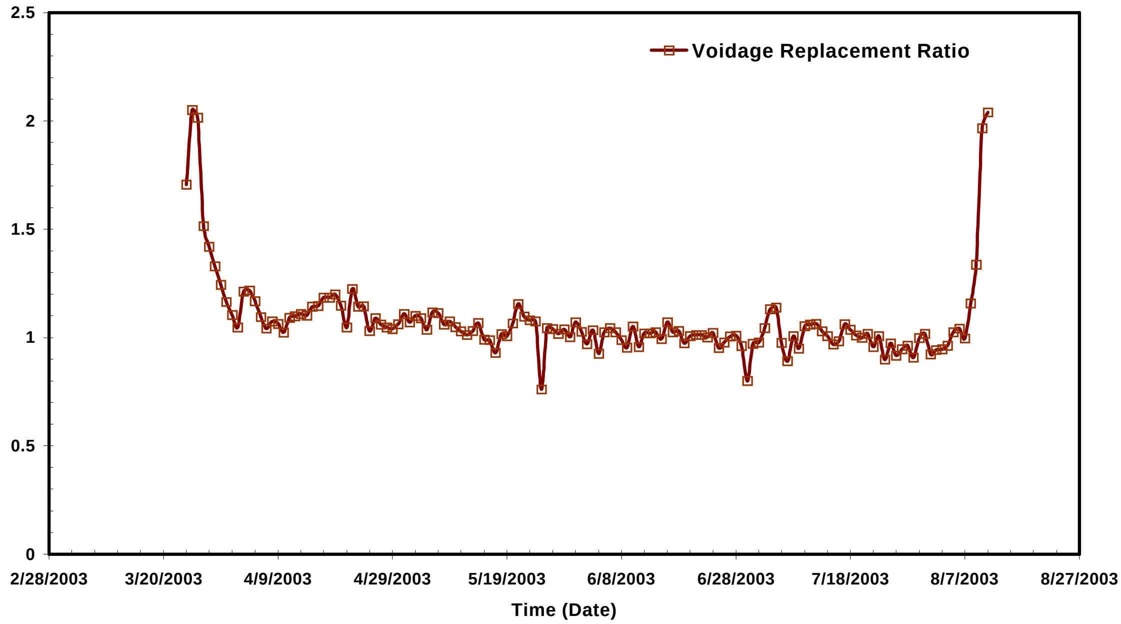

Fig.3. 5-Voidage Replacement Ratio for the Second Period of Injection

3.3 On-trend and Off-trend wells

A major objective of this part of the study was to corroborate fracture orientation and identify waterflood response based on the performance of on-trend and off-trend wells. In this part of the study, production plots were generated to illustrate the differences in behavior and tendencies of both on-trend and off-trend wells.

Traditionally the fracture orientation in the Spraberry formations is known to be approximately 50 degrees east of north (N 50^{o} E). Through the use of production plots and bubble maps we tried to establish the behavior of the production and support this trend . The definition of on-trend and off-trend is with respect to the major fracture orientation trend; on-set wells follow the same orientation as the major fracture orientation (parallel to the fractures); whereas off-trend wells follow a direction different as the fracture orientation line. The on-trend and off-trend studied are shown in **Fig.3.6**

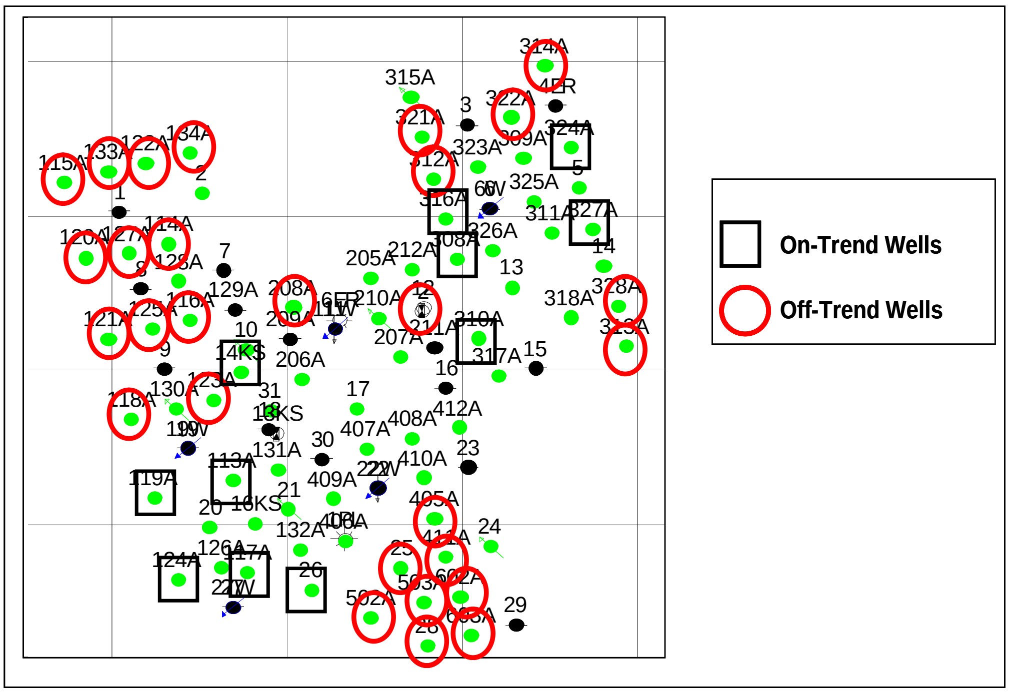

Fig.3. 6-Base Map Showing the On-trend and Off-trend wells.

Fig.3.7 shows the same peak in the average oil rate per well for both on-trend and off-trend producers. The oil peak illustrates the flushing out of the fracture system by the flooding water. The peaks are also followed by a somewhat hyperbolic type decline in the oil rate as the imbibition process progresses. The decline rate is about the same for both on-trends and off-trends. In early production time, the on-trends tends to have a slightly greater oil rate compared to the off-trend wells; but after a while both tend to have the same rate (in other words, the on-trends seems to have a faster response). On the other hand **Fig.3.8** shows that the water-oil ratio tends to increase in the off-trend shortly after the injection process was initiated (in 1965) and exhibit a higher water-cut than the on-trend wells most of the time until they both tend to reach the same value of water-oil rate.

The explanation for this behavior is based on wettability effects. Since the reservoir is weakly-water wet, the rock tends to imbibe the water being injected pushing the fluid (movable oil and water) towards the off-trend wells. The water being injected is moving much slower into the fractures. This performance suggests that this reservoir is water-wet (this is in agreement with the results obtained through core analyses performed in the area) indicating that the performance is greatly influenced by the wettability of the rock. This also corroborates that the fracture orientation is 56 degrees east of north (N 56^{o} E). The performance of both on-trends and off-trends has showed oil bank followed by sharp breakthrough of the water front.

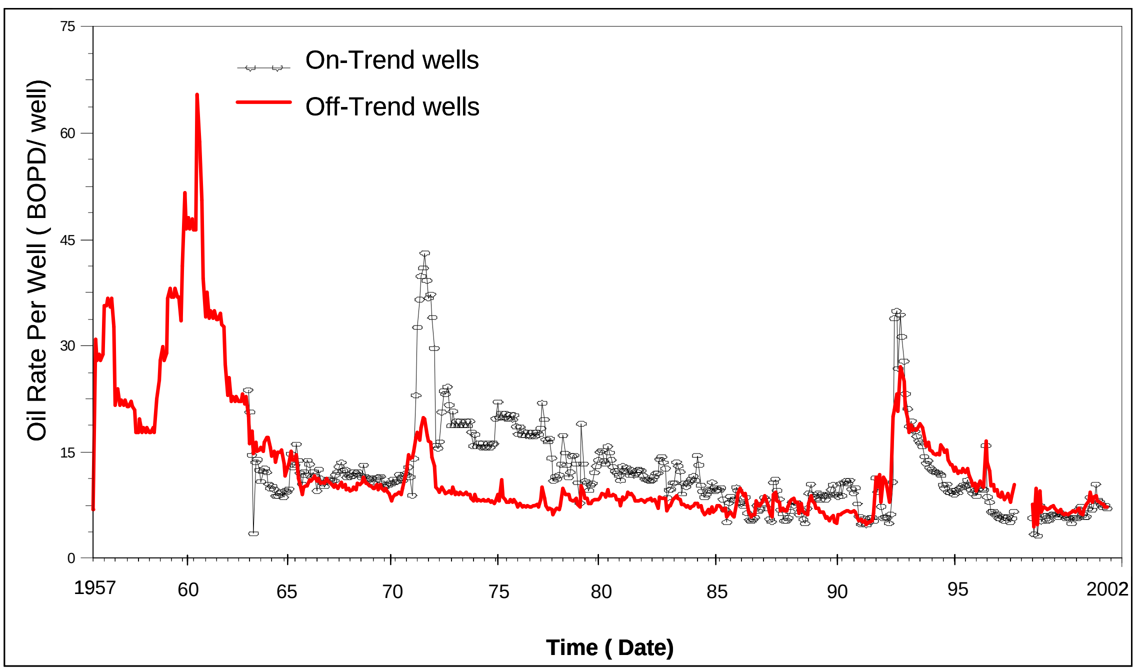

Fig.3. 7-Oil Rate per well for On-trend and Off-trend wells.

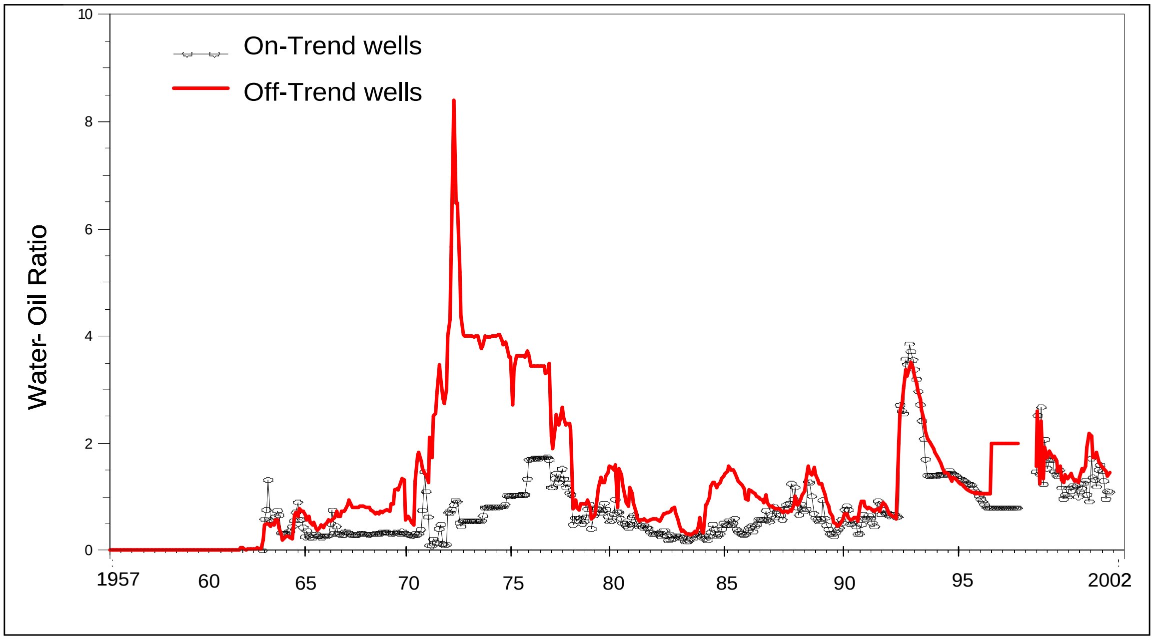

Fig.3. 8-Average water-Oil ratio for On-trend and Off-trend wells.

3.4 Vintaging Wells

To be able to compare the performance of wells drilled in different time of the unit development, it was necessary to determine the date of first production for each well. The wells were sorted according to their age and assigned to groups (vintages) for specific purposes. This is very important to evaluate the individual performance of the different vintages and select the best practices and operations utilized for each group as well as evaluating the impact of them on the recovery. **Fig.3.9,** shows the different vintages or drilling campaigns used by the operator to develop the unit.

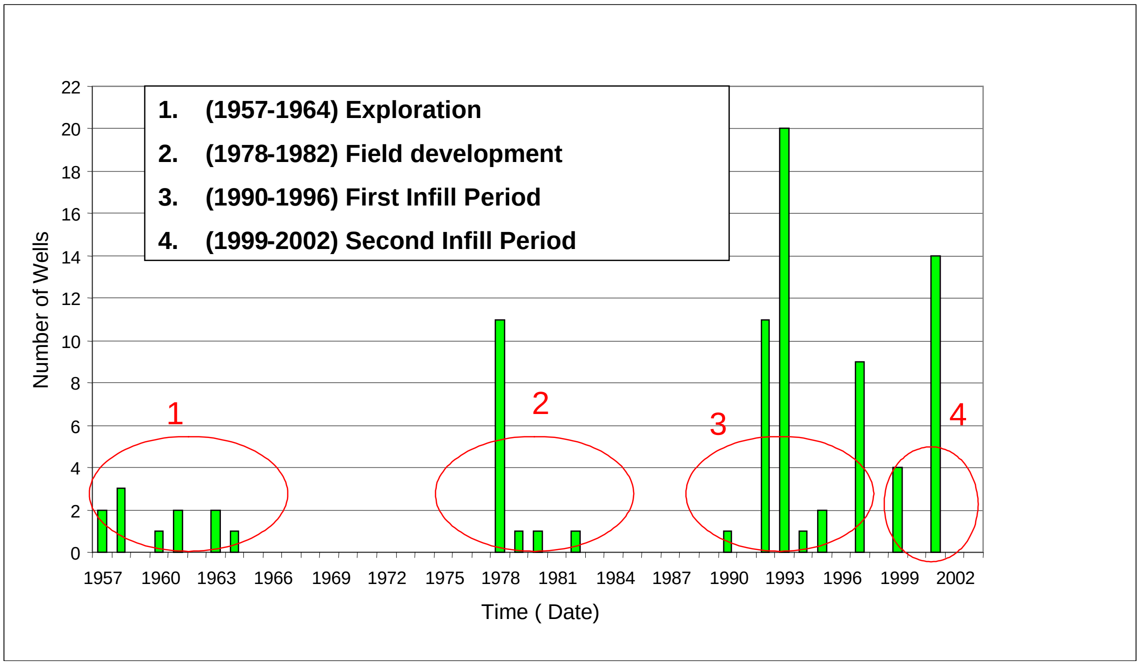

Fig.3. 9-Different Drilling Campaigns for Development of Germania Spraberry Unit.

3.4.1 Vintage 1957-1963.

A total of 11 wells were drilled and produced from 1957 to 1964 to explore and develop the field. They were drilled in different locations of the unit. The purpose of this group of wells was to develop the reservoir when the field was under primary production. **Fig.3.10** shows the location of the wells drilled from 1957 to 1963. Of this 11 wells, a total of three (GSU-11, GSU-17, and GSU-22) were converted into water injectors in January 2003 when the injection pattern was changed and are currently injecting 800 BWPD; two are still active (GSU-12 and GSU-26); two are temporarily plugged and abandoned, and four were abandoned. Wells drilled and produced during this period showed medium initial oil rate of 48 BOPD as shown in **Fig.3.11** and **Table 3.2.**

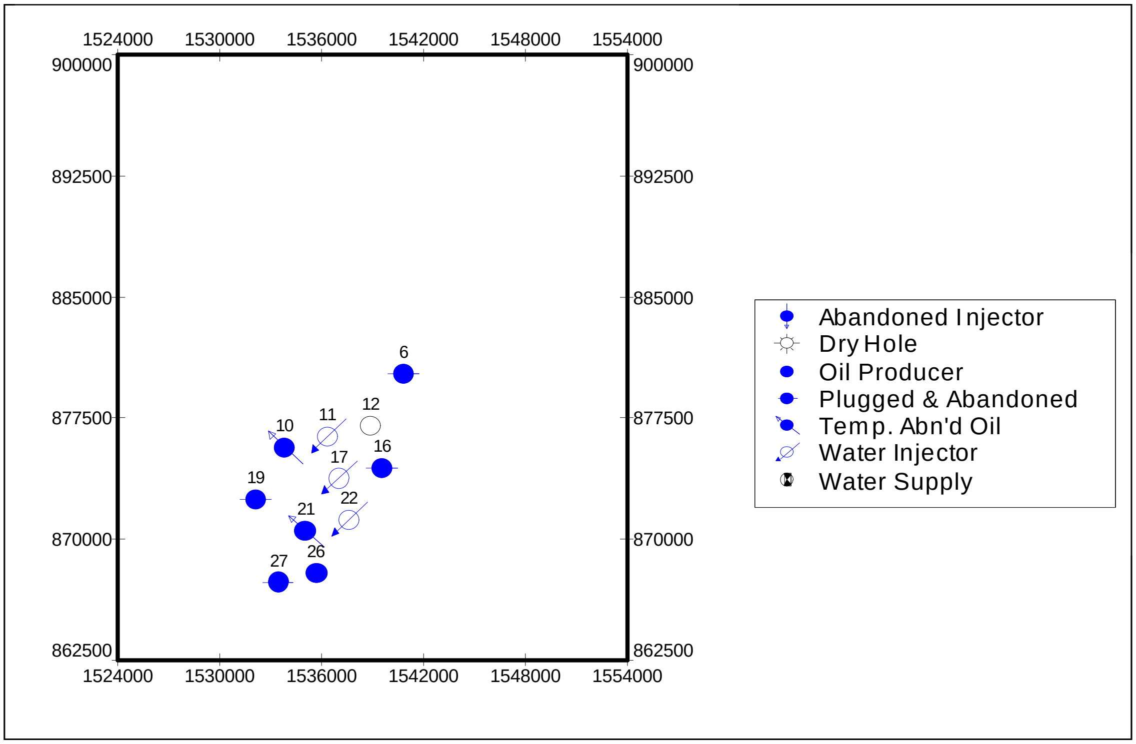

Fig.3.10-Base Map showing the Location of Wells Drilled from 1957 to 1963.

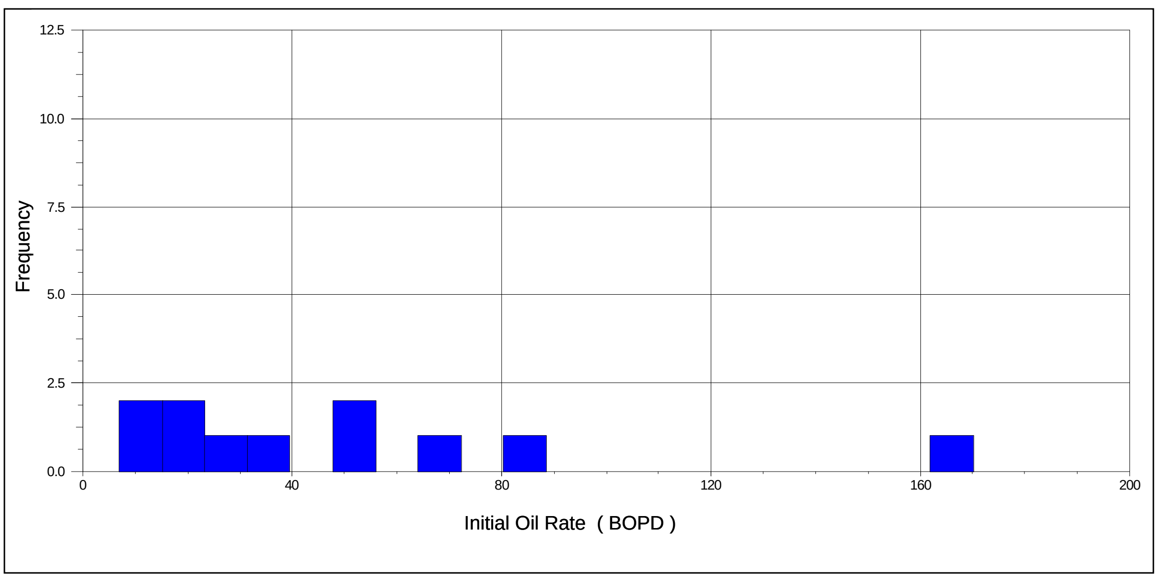

Fig.3. 11-Histogram of Initial Oil Rate for Wells Drilled from 1957 to 1963.

Table 3. 2-Statistical Analysis for Wells Drilled from 1957 to 1963.

First Oil rate (BNPD)	
Samples:	11
Minimum:	6.8972
Maximum:	170.1338
Range:	163.2366
Medium:	88.5155
Sum:	533.5898
Arithmetic Average:	48.5082
Geometric Average:	31.5498
Variance:	2061.6347
Abs Deviation:	33.6007
Sample Std Deviation:	47.6214
Pop. Std Deviation:	45.4052

3.4.2 Vintage 1978-1982

A total of 14 wells were drilled during the second drilling campaign (from 1978 to 1982) to develop the field. They were drilled in different locations of the unit and in a 160 acre-spacing. The purpose of this group of wells was to develop the reservoir when the field was already under secondary production (the campaign began 13 years after the initiation of the waterflooding process). **Fig.3.12** shows the location of the wells drilled from 1978 to 1982. Of this 14 wells, a total of seven (GSU-2, GSU-13, GSU-14, GSU-20, GSU-25, GSU-28, and GSU-31) are currently active and seven are plugged and abandoned (GSU-1, GSU-9, GSU-23, GSU-29, GSU-18, GSU-3, and GSU-7) due to either low productivity or high water curt (average was 80 percent) that they experienced shortly after they began producing. Wells drilled and produced during this period showed a medium initial oil rate of only 11 BOPD as shown in **Fig.3.13** and **Table 3.2.**

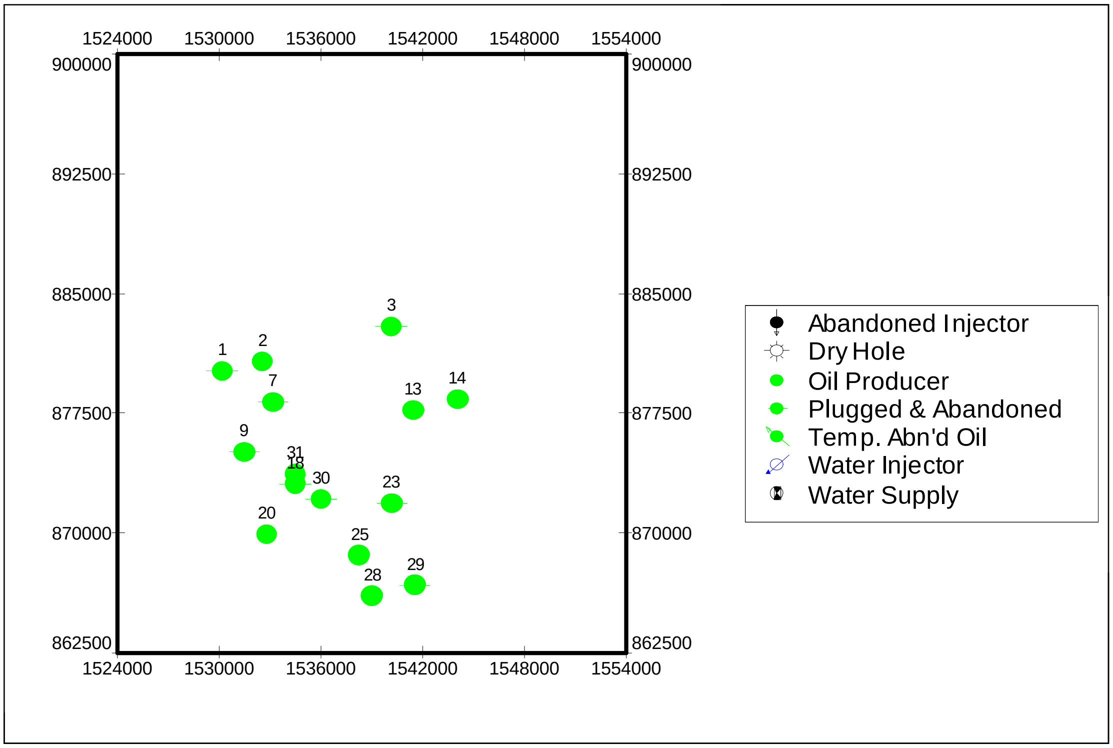

Fig.3. 12-Base Map showing the Location of Wells Drilled from 1978 to 1982.

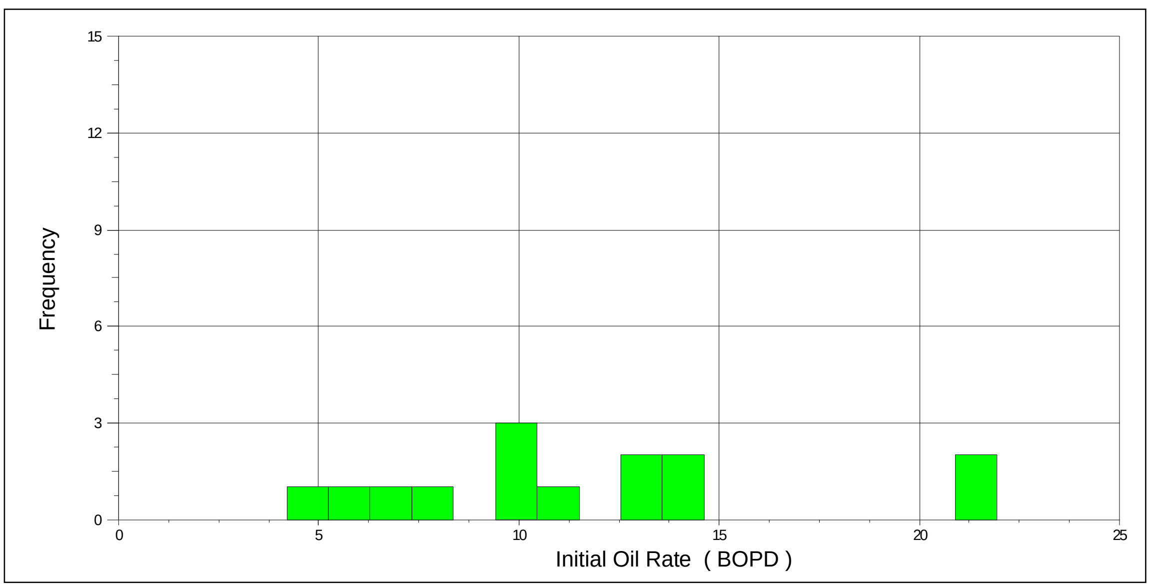

Fig.3. 13 -Histogram of Initial Oil Rate for Wells Drilled from 1978 to 1982.

Table 3. 3 Statistical Analysis for Wells Drilled from 1978 to 1982.

First Oil rate (BNPD)	
Samples:	14
Minimum:	1.0645
Maximum:	21.9355
Range:	20.8710
Medium:	11.5000
Sum:	162.6757
Arithmetic Average:	11.6197
Geometric Average:	10.6261
Variance:	24.6767
Abs Deviation:	3.9514
Sample Std Deviation:	5.1551
Pop. Std Deviation:	4.9676

3.4.3 Vintage 1990-1996

A total of 44 wells were drilled during this infill-drilling campaign (from 1990 to 1996) to develop the field. They were drilled to reduce the spacing to 80 acres. The purpose of this group of wells was to develop the reservoir when the field was already under secondary production (this campaign began 25 years after the initiation of the waterflooding process). **Fig.3.14** shows the location of the wells drilled from 1990 to 1996. Of this 44 wells, a total of 37 are currently active, which represents more than 50 percent of the active wells in the unit; 3 are temporarily plugged and abandoned due to either low productivity or the high water curt (average was 80 percent) that they experienced shortly after they began producing, and two (GSU-407 and GSU-410) were converted to water injectors in January 2003 having a water injection rate of about 540 BWPD. Wells drilled during this period experienced a medium initial oil rate of 44 BOPD as shown in **Fig.3.15** and **Table 3.3.**

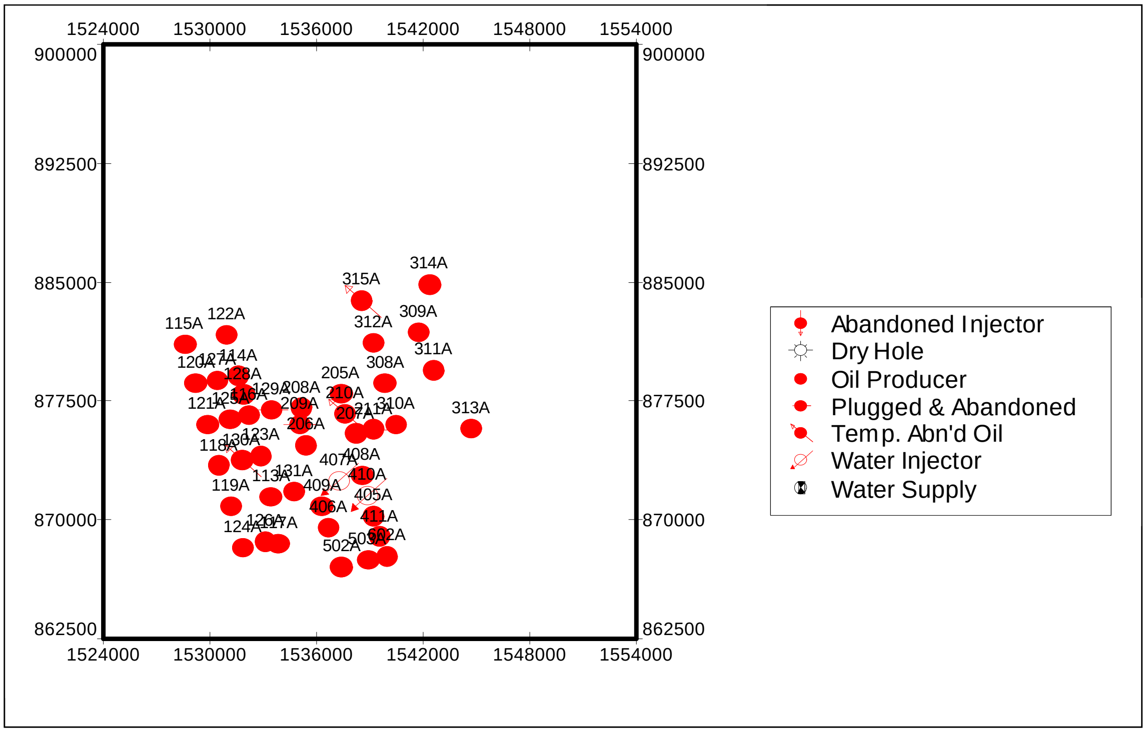

Fig.3. 14-Base Map showing the Location of Wells Drilled from 1990 to 1996.

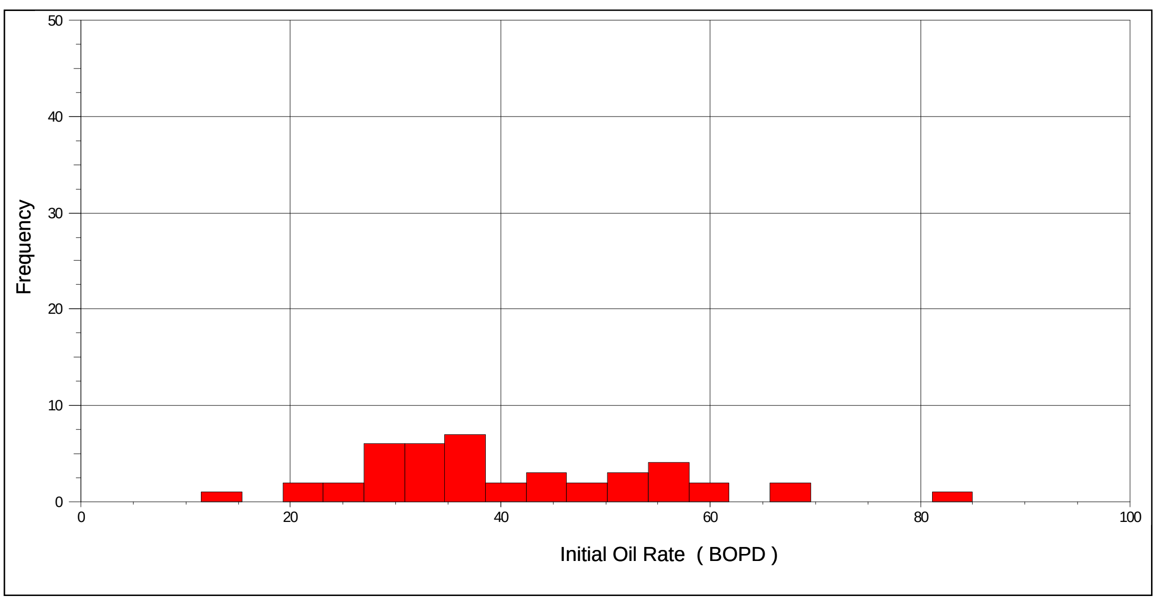

Fig.3. 15-Histogram of Initial Oil Rate for Wells Drilled from 1990 to 1996.

Table 3. 4 Statistical Analysis for Wells Drilled from 1990 to 1996.

```
Statistical Analysis
---------- --------
First Oil rate ( BNPD)
             Samples:              42
             Minimum:          7.6393
             Maximum:         81.2000
               Range:         73.5607
              Medium:         44.4196
                 Sum:       1667.0433
  Arithmetic Average:         39.6915
   Geometric Average:         37.4718
            Variance:        169.2272
       Abs Deviation:         10.8822
Sample Std Deviation:         13.1664
  Pop. Std Deviation:         13.0087
```

3.4.4 Vintage 1999-2002

A total of 18 wells were drilled during this infill drilling campaign (from 1999 to 2002) to develop the field. They were drilled to reduce the spacing to 40 acres. The purpose of this group of wells was to develop the reservoir when the field was already under secondary production (this campaign began 42 years after the initiation of the waterflooding process). **Fig.3.16,** shows the location of the wells drilled from 1999 to 2002. All wells drilled during this period are currently active, producing with a moderate average water cut. Wells drilled during this period experienced medium initial oil rate of only 15 BOPD as shown in **Fig.3.17** and **Table 3.5.**

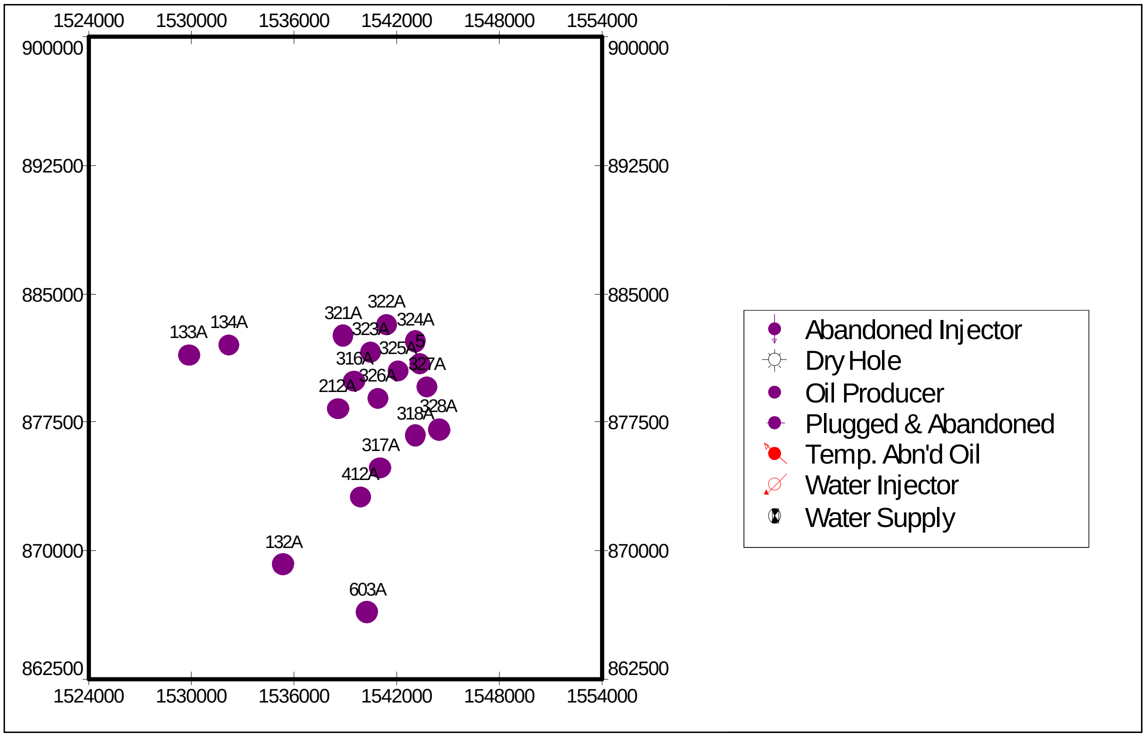

Fig.3. 16-Base Map showing the Location of Wells Drilled from 1999 to 2002.

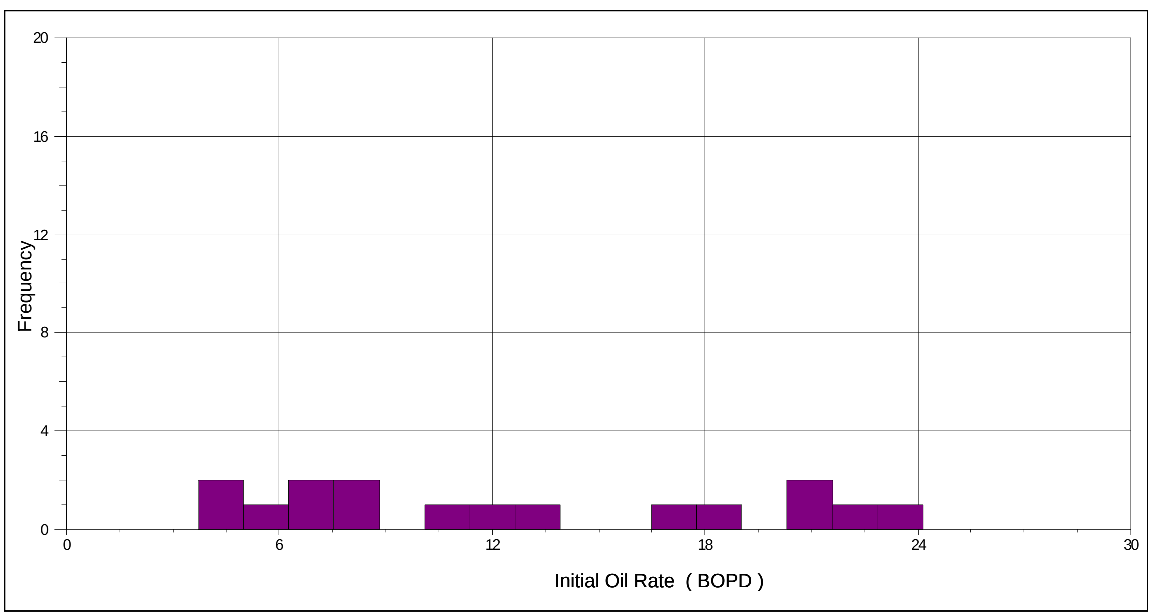

Fig.3. 17-Histogram of Initial Oil Rate for Wells Drilled from 1999 to 2002.

Table 3. 5 Statistical Analysis for Wells Drilled from 1999 to 2002.

```
Statistical Analysis
---------- --------
First Oil rate ( BNPD)
             Samples:            16
             Minimum:        2.4235
             Maximum:       27.9835
               Range:       25.5600
              Medium:       15.2035
                 Sum:      201.7435
  Arithmetic Average:       12.6090
   Geometric Average:       10.8083
            Variance:       42.6894
       Abs Deviation:        5.8581
Sample Std Deviation:        6.7480
  Pop. Std Deviation:        6.5337
```

3.4.5 Comparative Analysis for Vintages

According to **Fig.3.18,** the second drilling campaign (1996 to 1996) is the one that exhibits the highest current production rate because is the one with the most wells drilled (44 wells).

Fig.3.19, shows that all wells belonging to the four different campaigns, exhibit about the same decline rate**.** In this plot, we can also observe that the vintage that exhibit the highest average initial oil rate per well is the campaign of wells drilled between 1957 and 1964 (48 BOPD). It is because they were drilled when the reservoir had original pressure and initial oil water saturation**.**

Wells drilled between 1978 and 1982, had the lowest average initial oil rate (11 BOPD) even though they were drilled in the second campaign, when the water saturation and the cumulative water injected were lower than the existing in the reservoir when the third and four campaigns took over. However, after 6,000 days in production the oil rate of this group of wells (campaign 1978 to 1982) is greater than its initial rate; this is an indication of the response of the injection in this set (normally most of the floods take a long time to increase oil production as a result of large distances between the injectors and the producers; especially if the permeability of the formation is low). This response is also seen in the first drilling campaign (1957 to 1964) after 750 days in production and in the third drilling campaign (1990 to 1996) after 1,000 days in production as shown in **Fig.3.19.** The wells drilled between 1999 and 2002 have shown little or no response to the water injection. The effect showed by the different group of wells, are due to the reduction of the well spacing which enhances the injection/production profile and connectivity.

Fig.3.20, shows that wells drilled between 1957 and 1964 exhibit the highest initial water-oil ratio. However; as the rest of the wells were drilled, the different campaigns tended to reach the same value of water-oil ratio, averaging a current value of 2.

Historically; wells drilled during the third campaign (1990 to 1996), and the fourth campaign (1999 to 2002) have an initial oil rate higher than the remaining two campaigns. This is because in the third and fourth campaigns, the wells accessed an area previously unflooded by the wells in the first and second campaigns.

Fig.3.21; shows the cumulative oil production reached by the wells of the four different drilling campaigns. The wells drilled in the first campaign exhibit the highest oil cumulative (1.4 million barrels) because they have been in production through the entire life of production of the unit.

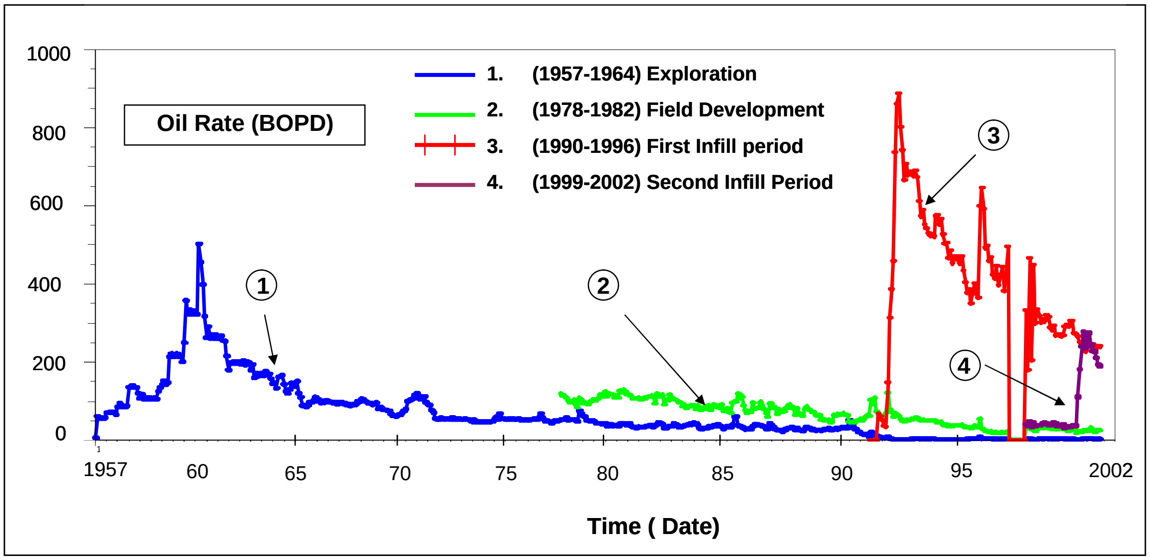

Fig.3. 18-Histogram of Initial Oil Rate for Wells Drilled from 1999 to 2002.

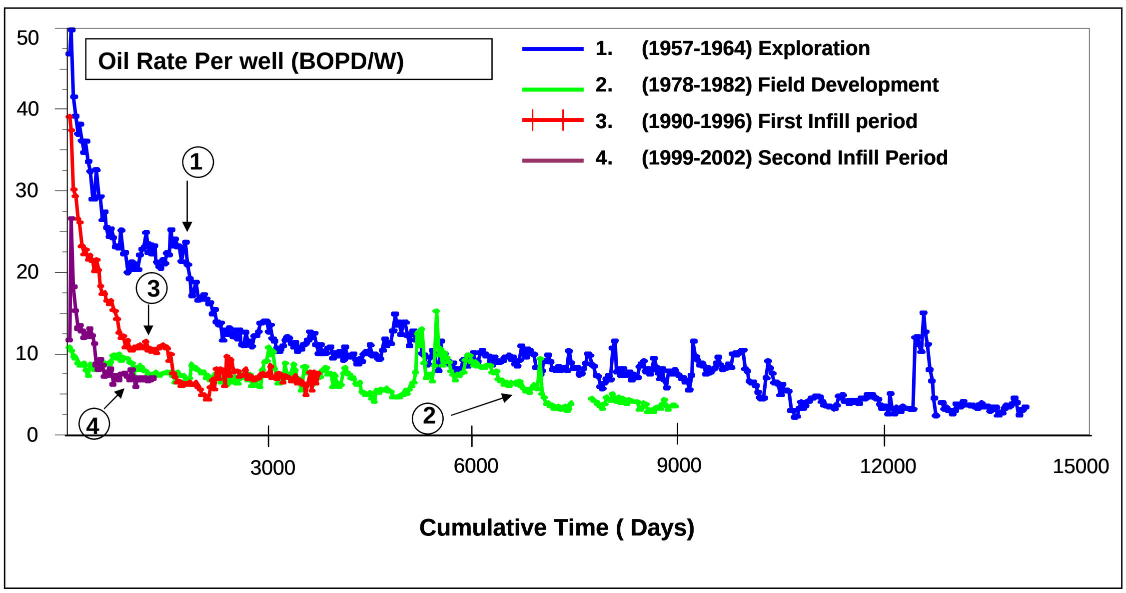

Fig.3. 19-Historical Oil Rate per well for Different Campaigns of wells during the Development of Germania Spraberry Unit.

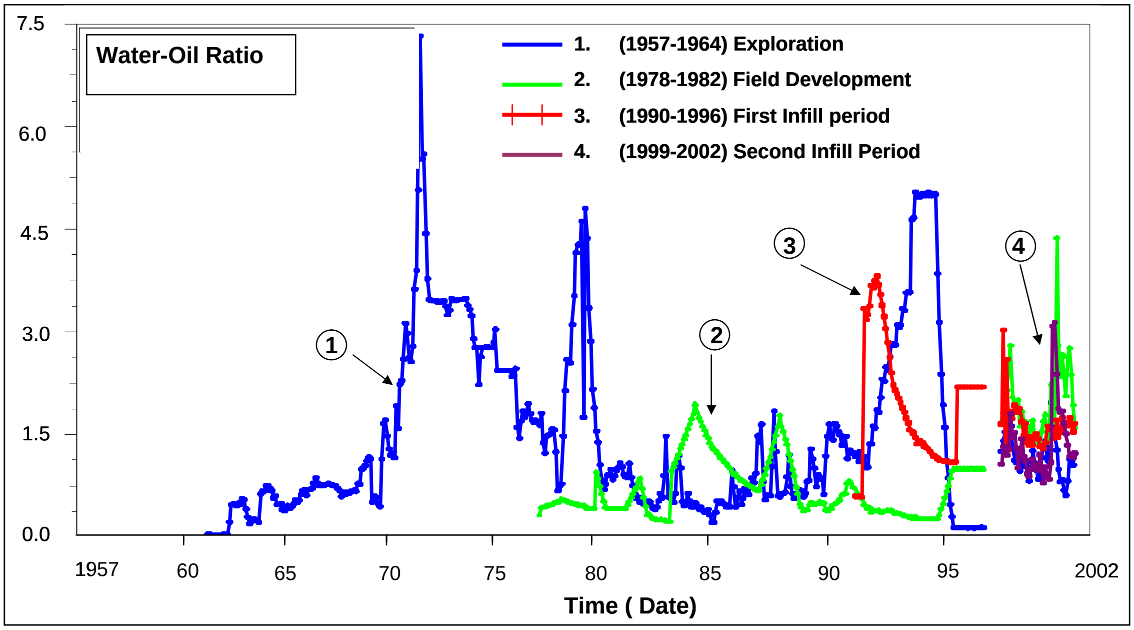

Fig.3. 20-Historical Water-Oil Ratio for Different Campaigns of wells during the Development of Germania Spraberry Unit.

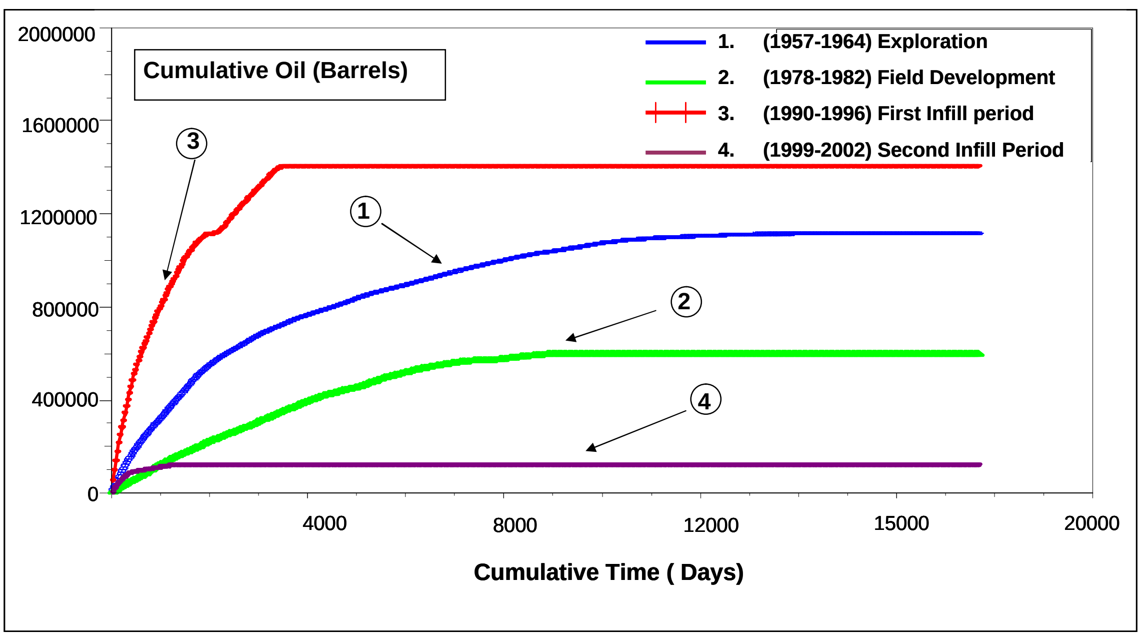

Fig.3. 21-Cumulative Oil Production for Different Campaigns of wells during the Development of Germania Spraberry Unit.

3.5 Individual Tracts.

The Germania Spraberry Unit, have been subdivided into 6 different areas (tracts). Each individual area was study and further comparisons among the different areas were made in this study. **Fig.3.22** shows the location and definition of the six different areas in Germania Spraberry Unit.

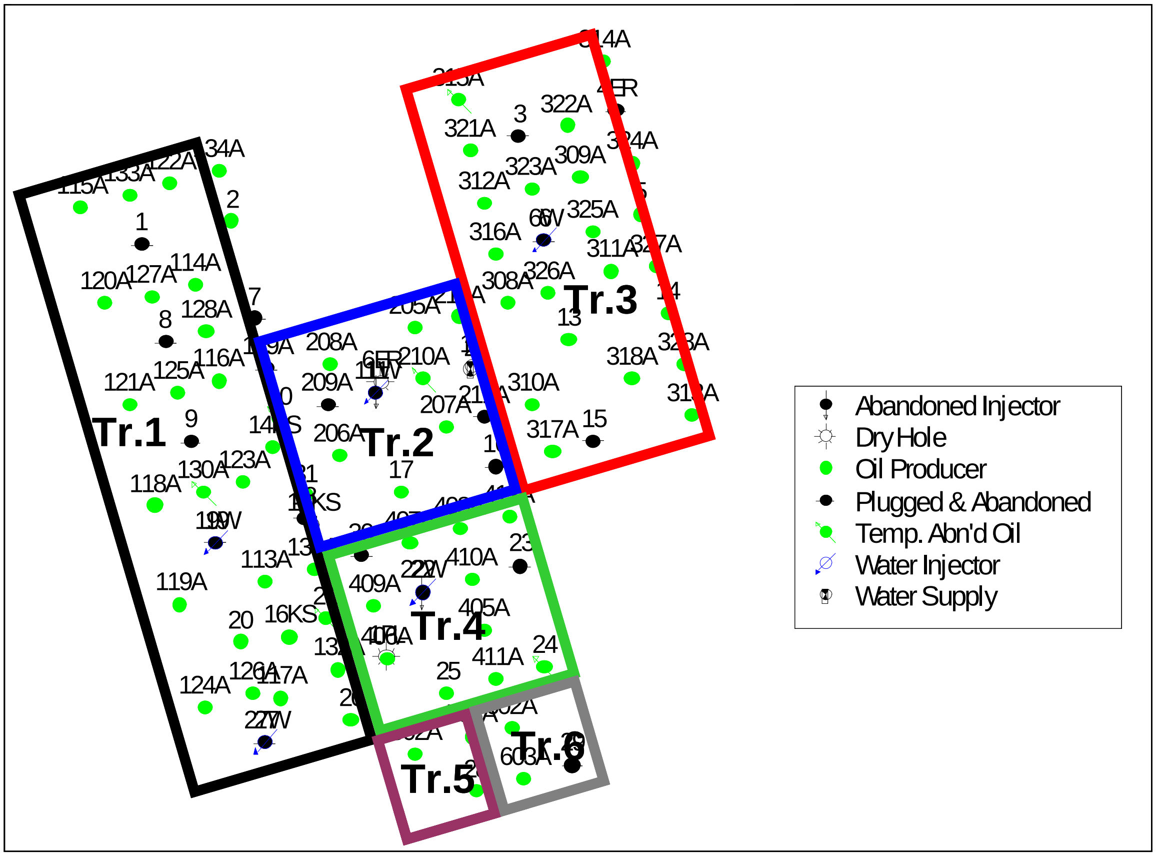

Fig.3. 22-Location of Individual Tracts in Germania Spraberry Unit.

3.5.1 Tract. 1

Tract 1 comprises the largest area present in Germania Spraberry Unit. It has an area of 1874 acres and has been developed since the discovery of the unit in 1957. It is also the tract with the most producer wells (33). Water breakthrough in this tract occurred in 1963 (6 years after the initiation of the development of the field) and the water cut continued to grow up to 90 percent in 1992 because of the water injection response showed by some wells located in this area (water injectors GSU-19 and GSU-27 were located in this tract). As shown in **Fig.3.23,** the production in this tract reached a maximum peak at 400 BOPD in 1993 and the average water cut have been 60 percent. As shown in **Fig.3.24,** the development of this part of the reservoir has been mostly based on the increment of the number of producers through the 4 drilling campaigns. This area has a total of 33 wells 24 of which are currently active with a total oil production of 170 BOPD (37 percent of the oil currently being produced in the entire unit).

3 of the 5 largest producers of the unit are located in this area (well GSU-10, GSU-21, and GSU-26 which exhibit a cumulative oil production of 126,979; 159,771; and 159,157 respectively and have been active for a long period of time. As of June 2003, this area has a cumulative oil production of 1.425 million barrels which represents 43.25 percent of the total produced by the entire unit.

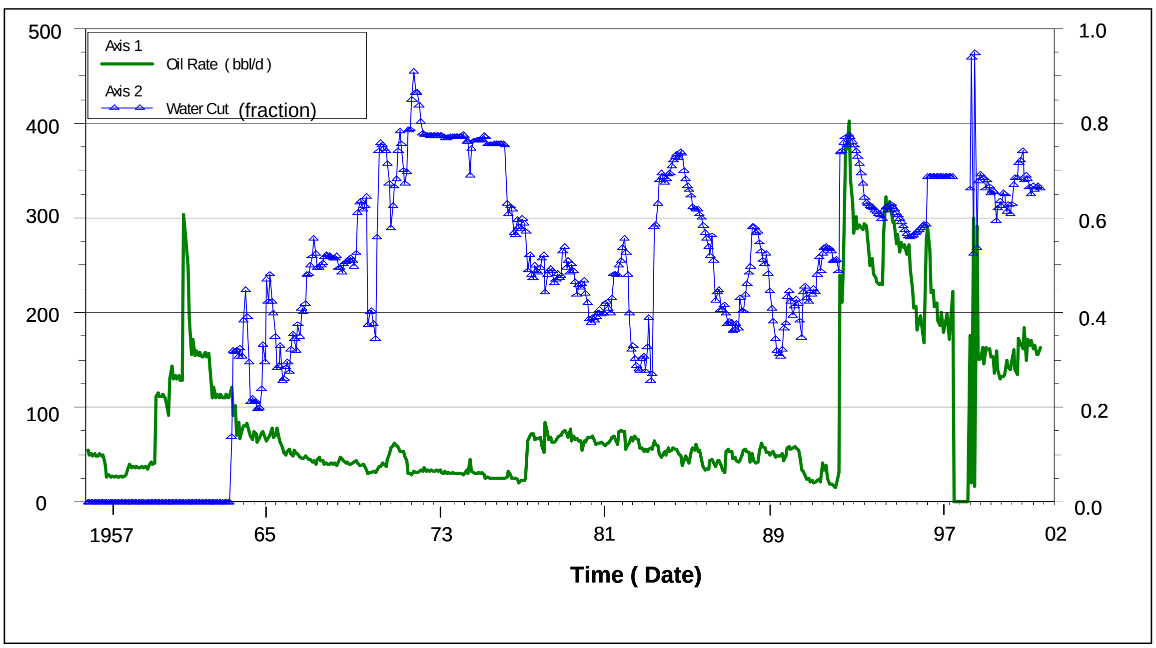

Fig.3. 23-Oil Rate and Water Cut for Tract 1. (Germania Spraberry Unit.)

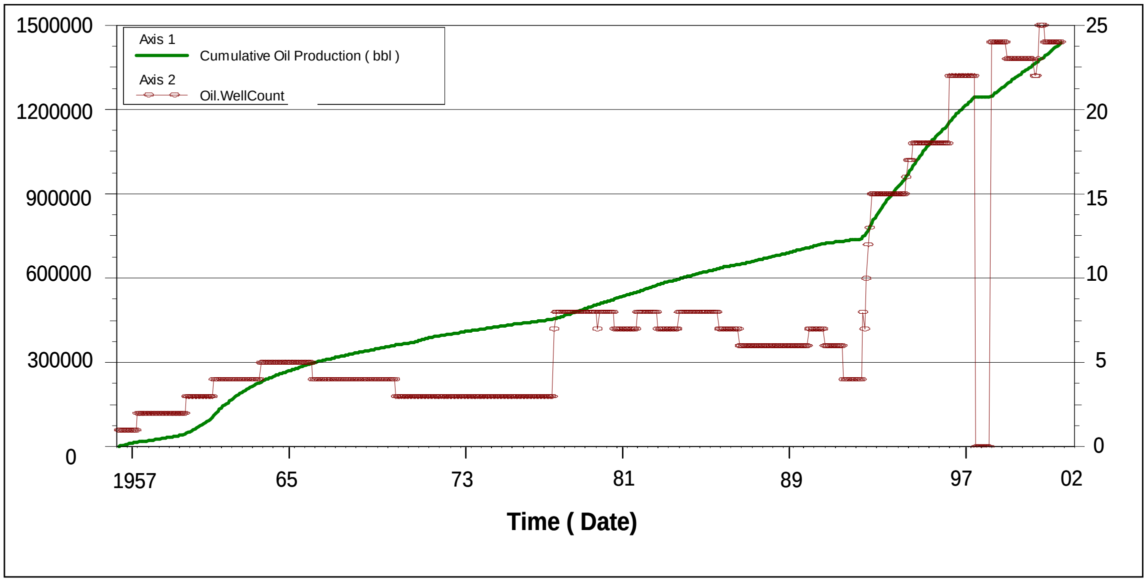

Fig.3. 24-Cumulative Oil Production and Active wells for Tract 1. (Germania Spraberry Unit).

3.5.2 Tract. 2

The tract 2 comprises an area of 663 acres and has been developed since the discovery of the unit in 1957. Water breakthrough in this tract occurred in 1963 (6 years after the initiation of the development of the field) and the water cut continued to grow up to 90 percent in 1971 because of the water injection response showed by some wells located in this area (water injector GSU-11 was located in the center of this tract). As shown in **Fig.3.25,** the production in this tract reached a maximum peak at 170 BOPD in 1961 (before the waterflooding project was implemented) and the average water cut have been 60 percent. As shown in **Fig.3.26,** the development of this part of the reservoir has been mostly based on the increment of the number of producers through the 4 drilling campaigns. This area has a total of 5 wells producing, with a total oil production rate of 38 BOPD (this represents only 7.8 percent of the oil currently being produced in the entire unit).

2 of the 5 largest producers of the unit are located in this area (wells GSU-16 and GSU-17 which exhibit a cumulative oil production of 117,414 and 177,119 respectively and have been active for a long period of time). As of June 2003, this area has a

cumulative oil production of 0.622 million barrels which represents 19 percent of the total produced by the entire unit.

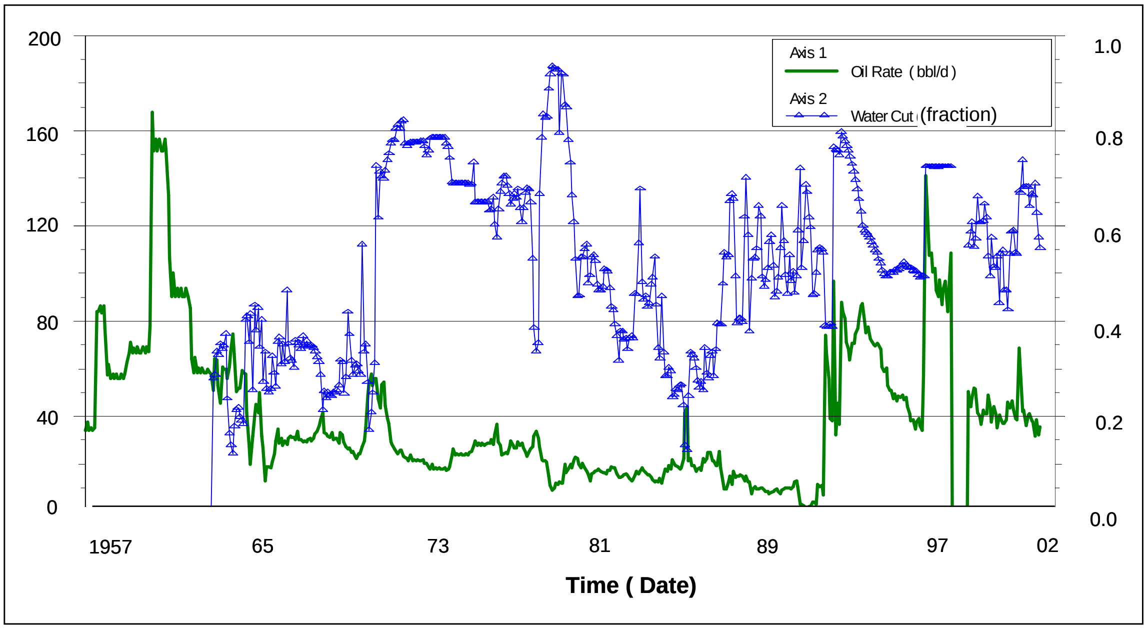

Fig.3. 25-Oil Rate and Water Cut for Tract 2. (Germania Spraberry Unit.)

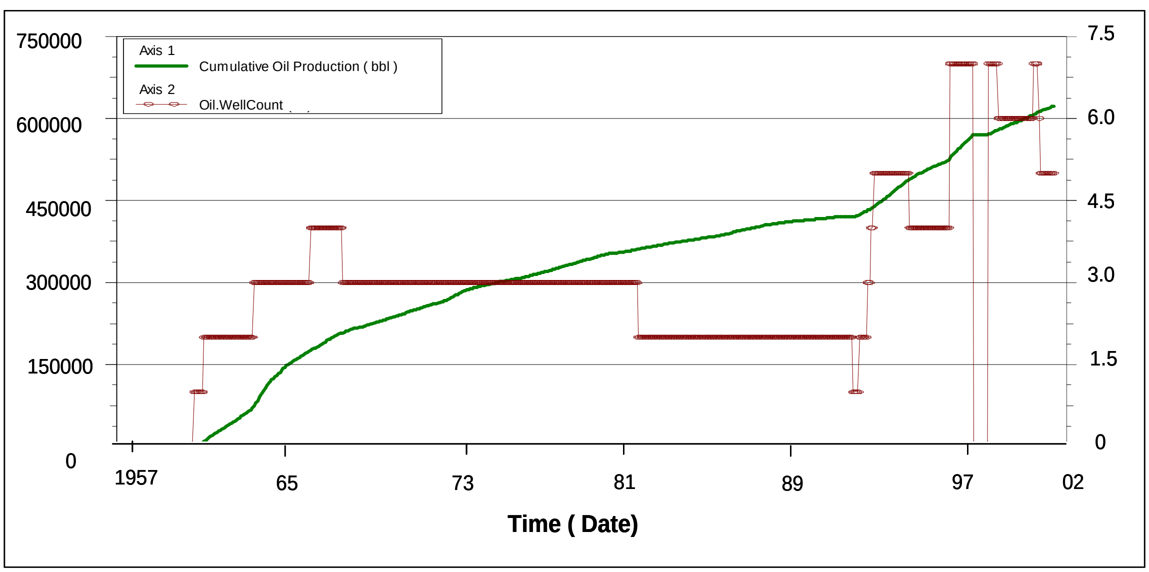

Fig.3. 26-Cumulative Oil Production and Active wells for Tract 2. (Germania Spraberry Unit).

3.5.3 Tract. 3

The tract 3 comprises an area of 1345 acres and has been developed since the 1963 (6 years after the discovery of the unit). Water breakthrough in this tract occurred in 1963 and the water cut continued to increase up to 99 percent in 1971. The well responsible for the high water cut was the well GSU-6 located in the center of the tract (the only active well in tract 3 at that time). This well was later converted to water injector in 1971. As shown in **Fig.3.27,** the production in this tract is currently about 195 BOPD (41.4% of the total being produced in the entire unit) and the average water cut is 50 percent. As shown in **Fig.3.28,** the development of this part of the reservoir has been mostly based on the increment of the number of producers through 3 drilling campaigns. This area has a total of 22 wells producing, with a total cumulative oil production of 0.579 million barrels (this represents 17.8 percent of the total produced in the entire unit).

Currently the central part of this tract is invaded by the water injected through the well GSU-6 (625,000 barrels of water injected) and the well GSU-11 located in tract 2 (760,000 barrels of water).

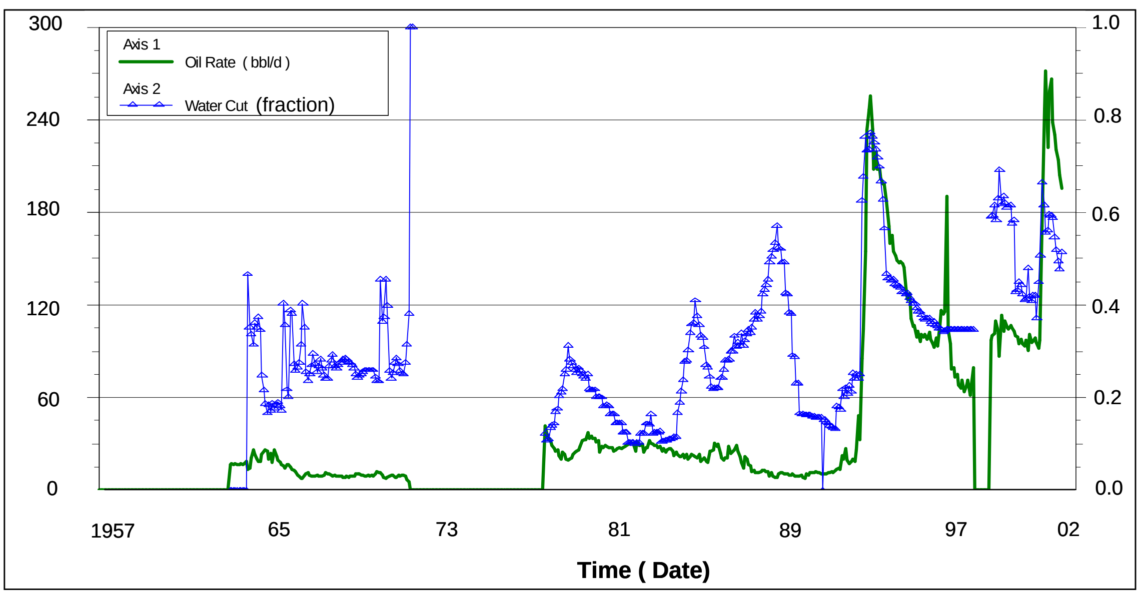

Fig.3. 27-Oil Rate and Water Cut for Tract 2. (Germania Spraberry Unit.)

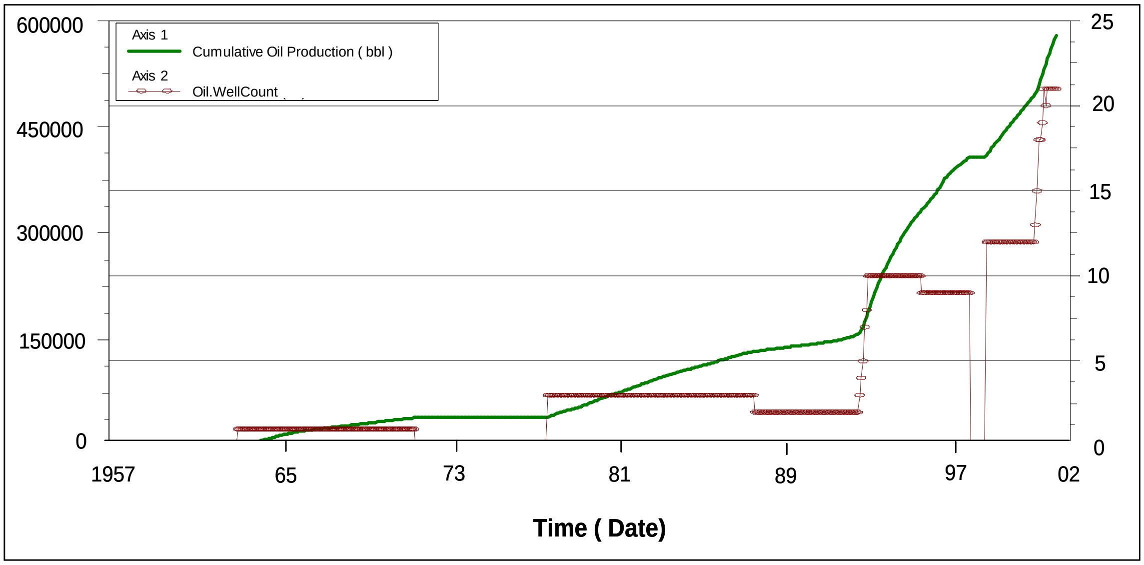

Fig.3. 28-Cumulative Oil Production and Active wells for Tract 2. (Germania Spraberry Unit).

3.5.4 Tract. 4

The tract 4 comprises an area of 663 acres and has been developed since the discovery of the unit in 1957. Water breakthrough in this tract occurred in 1962 (5 years after the initiation of the development of the field) and the water cut continued to increase up to 99 percent in 1969. The well responsible for the high water cut was the well GSU-22 located in the upper corner of the tract. This well was converted to water injector in November 1971 and is still injecting water as part of the new injection pattern acting in the reservoir. As shown in **Fig.3.29,** the production in this tract is currently about 50 BOPD (through 9 active wells) and the average water cut is 65 percent. As shown in **Fig.3.30,** the development of this part of the reservoir has been mostly based on the increment of the number of producers through 4 drilling campaigns. This area has a total of 9 wells producing (out of a total of 14), with a total cumulative oil production of 0.446 million barrels (this represents 12.75 percent of the total produced in the entire unit).

Currently the central part of this tract is invaded by the water injected through the well GSU-22 (722,182 barrels of water injected).

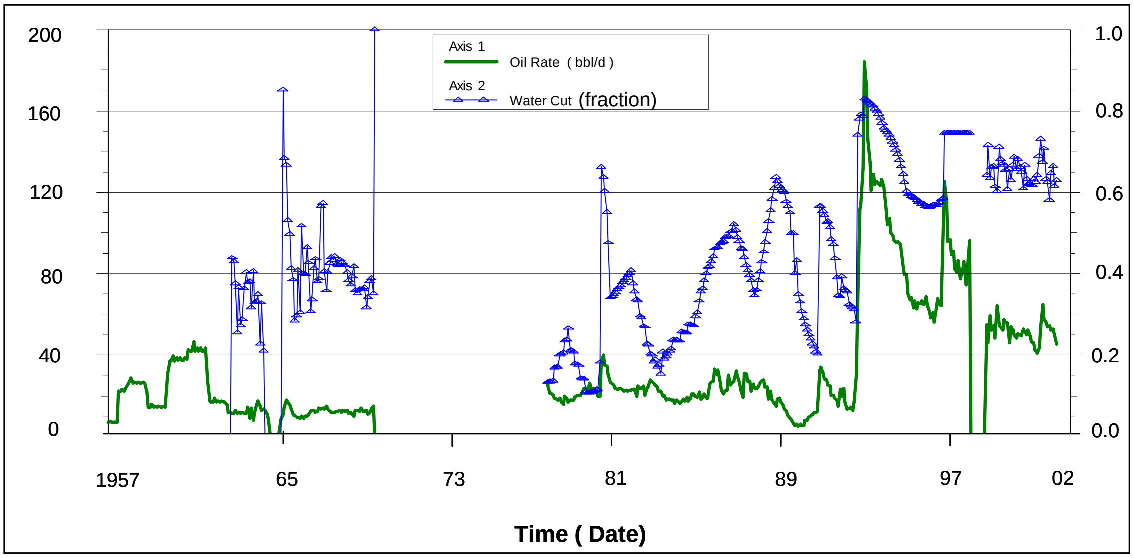

Fig.3. 29-Oil Rate and Water Cut for Tract 3 (Germania Spraberry Unit).

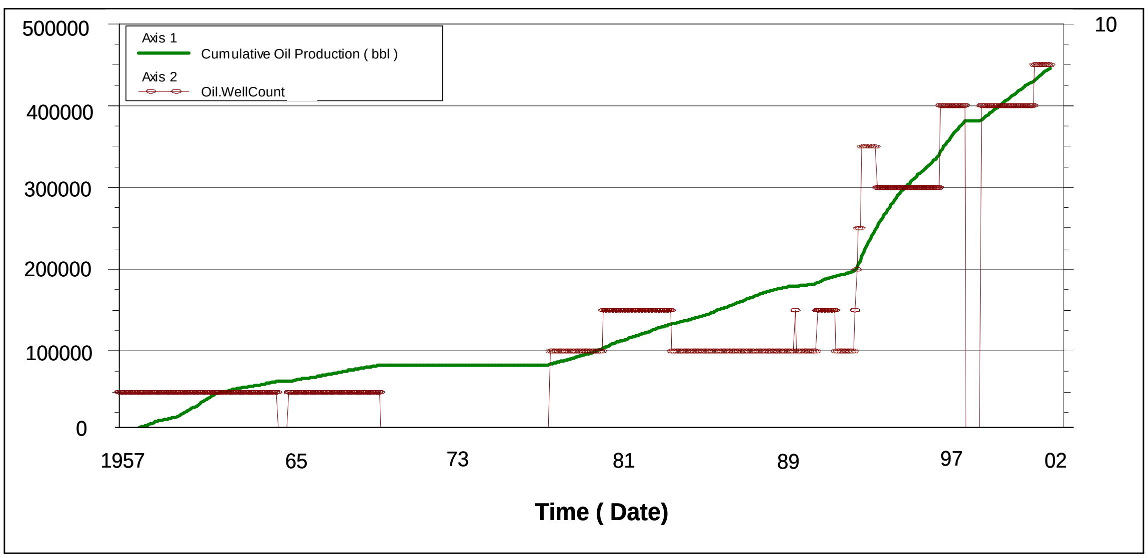

Fig.3. 30-Cumulative Oil Production and Active wells for Tract 3. (Germania Spraberry Unit).

3.5.5 Tract. 5

The tract 5 comprises an area of 166 acres and has been developed since the second drilling campaign in 1978. Water breakthrough in this tract occurred in 1985 and the water cut continued to increase up to 70 percent in 1988. As shown in **Fig.3.31,** the production in this tract is currently about 12 BOPD (through 3 active wells) and the historical average water cut has been 55 percent. As shown in **Fig.3.32,** the development of this part of the reservoir has been mostly based on the increment of the number of producers through 2 drilling campaigns. This area has only 3 wells producing and a total cumulative oil production of 0.098 million barrels (this represents only 3 percent of the total produced in the entire unit).

This tract has been developed only during the secondary stage of depletion and most of the water associated to the production of its well has been the result of the water injected in the tract 4 through the well GSU-22 (722,182 barrels of water injected).

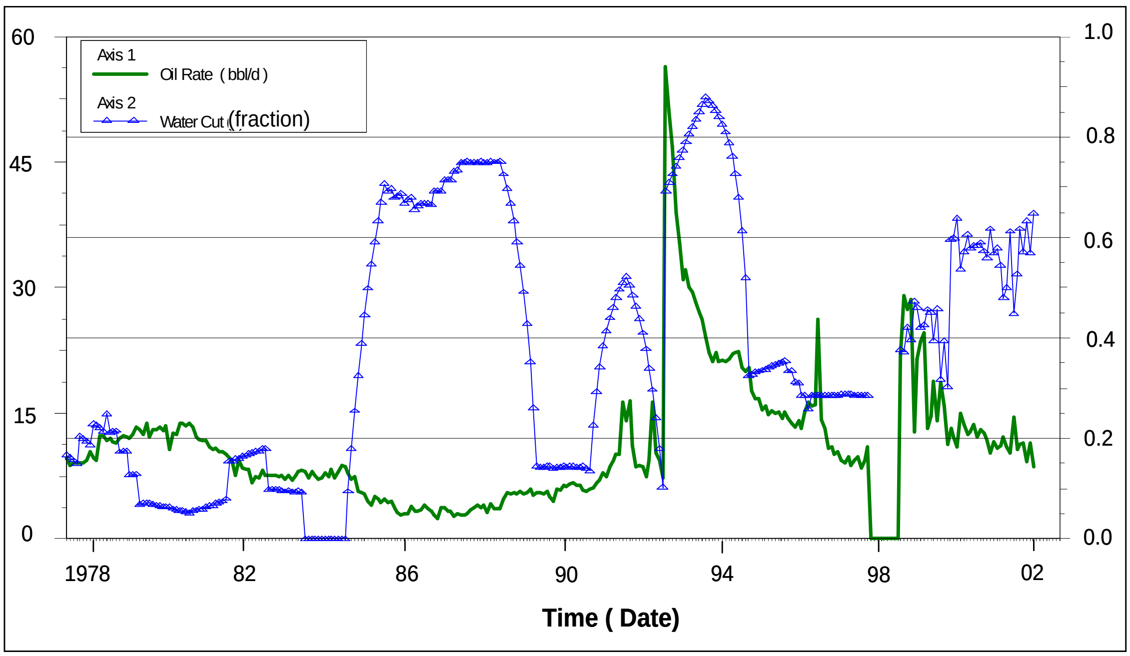

Fig.3. 31-Oil Rate and Water Cut for Tract 5 (Germania Spraberry Unit).

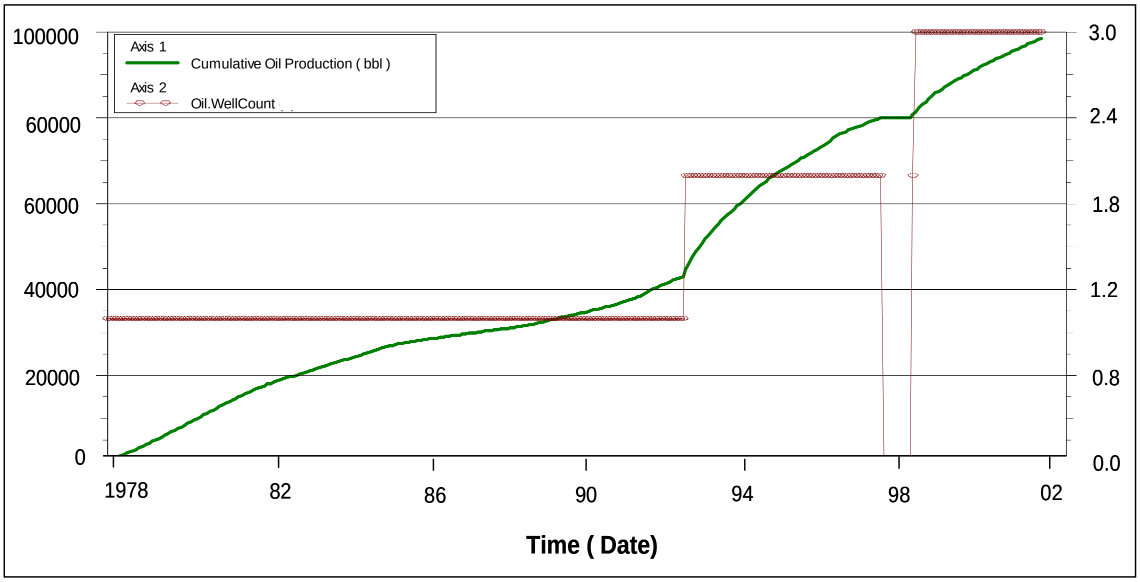

Fig.3. 32-Cumulative Oil Production and Active wells for Tract 5 (Germania Spraberry Unit).

3.5.6 Tract. 6

The tract 6 comprises an area of 166 acres and has been developed since the second drilling campaign in 1978. Water breakthrough in this tract occurred in 1984 and the water cut continued to increase to 70 percent in 1987. As shown in **Fig.3.33,** the production in this tract is currently 11 BOPD (through 2 active wells) and the historical average water cut has been 58 percent. As shown in **Fig.3.34,** the development of this part of the reservoir has been mostly based on the increment of the number of producers through 2 different drilling campaigns. This area has only 2 wells producing and a total cumulative oil production of 0.062 million barrels (this represents only 1.9 percent of the total produced in the entire unit).

This tract has been developed only during the secondary stage of depletion and most of the water associated to the production of its well has been the result of the water injected in the tract 4 through the well GSU-22 (722,182 barrels of water injected).

The well GSU-29 has been the most responsible for the production in this tract (produced for 14 years) and then the wells GSU-602 and GSU-603 were completed to continue developing the tract.

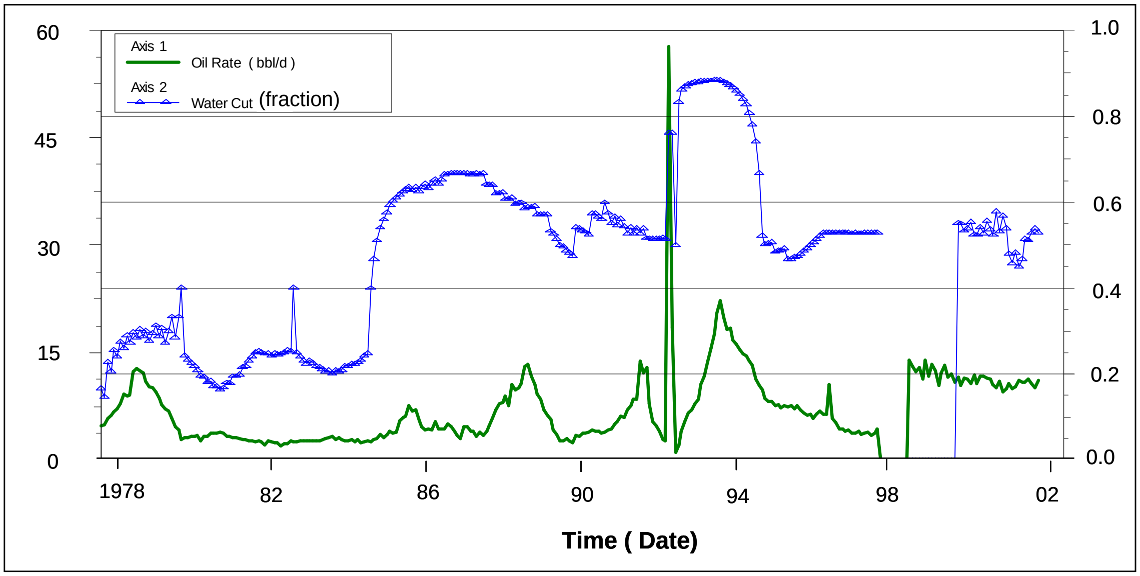

Fig.3. 33-Oil Rate and Water Cut for Tract 6 (Germania Spraberry Unit).

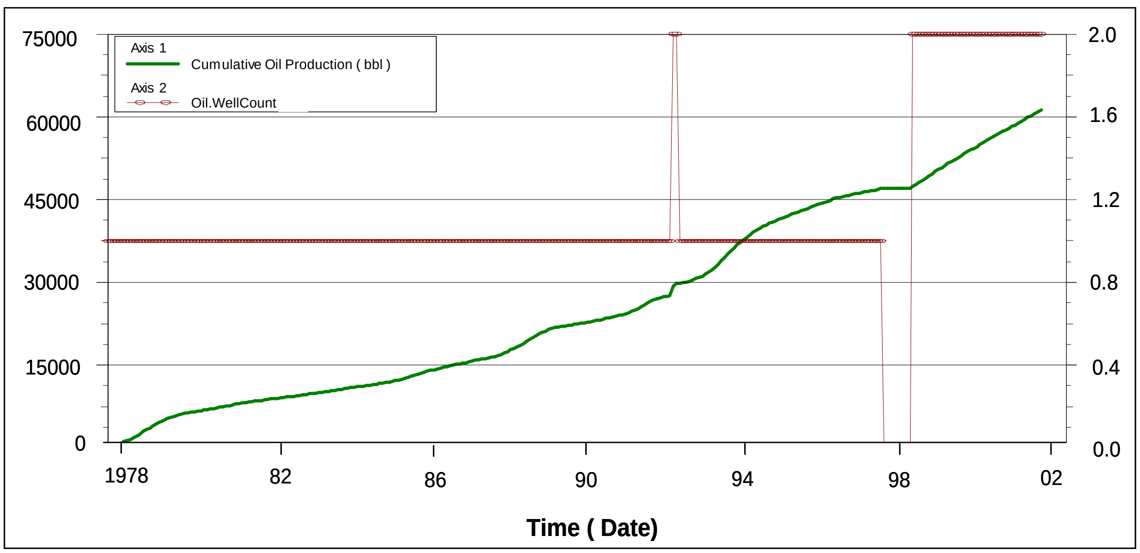

Fig.3. 34-Cumulative Oil Production and Active wells for Tract 6 (Germania Spraberry Unit).

3.5.7 Comparative Analysis for Tracts.

Fig.3.35, shows that tract 1 has the highest historical average oil rate (100 BOPD), and also has the most wells completed (a total of 40 producers have been completed in this tract.). As shown in **Fig.3.36,** the average oil rate per well have been very similar in all tracts, being the tract 3 the one with the highest value of oil rate per well at last date (9.2 BOPD/W). All tracts have also shown the same rate of decline throughout the entire history of production of the unit.

As shown in **Fig.3.35,** in 1992 (when the injection was suspended), there was a considerable increment in the oil rate in all tracts (average rate of increment per tract was 280 BOPD), this is due to the third drilling campaign (first infill drilling period) performed in all tracts.

Table 3.6 indicates that tract 2 has exhibited the best performance in terms of cumulative oil produced per acre (938 barrels per acre); because of the response of the waterflood in this area. This also suggests that is the most drained area of the unit. Under waeterflooding period, the average cumulative produced per acre is 110 barrels. In the entire unit, the average cumulative oil produced per acre is 664 barrels. This is a very poor performance compared to the average of Spraberry (463 barrels of oil produced per acre) and is perhaps and indication of the potential opportunity to increase the recovery in Germania Spraberry Unit.

As shown in **Fig.3.37**, the water-oil ratio, showed a value of 15 in tract 2 in 1979, as a consequence of the response of the water injected through well 6W (located in tract.3).The water-oil ratio, also showed a high value (19) in tract 1 in 1999 when the average water cut in this tract was 90 percent and the numbers of active wells increased from zero to 23. Tracts 3, 4, 5, and 6 have shown an historical average water-oil ratio of 3, indicating a uniform drainage in all these tracts.

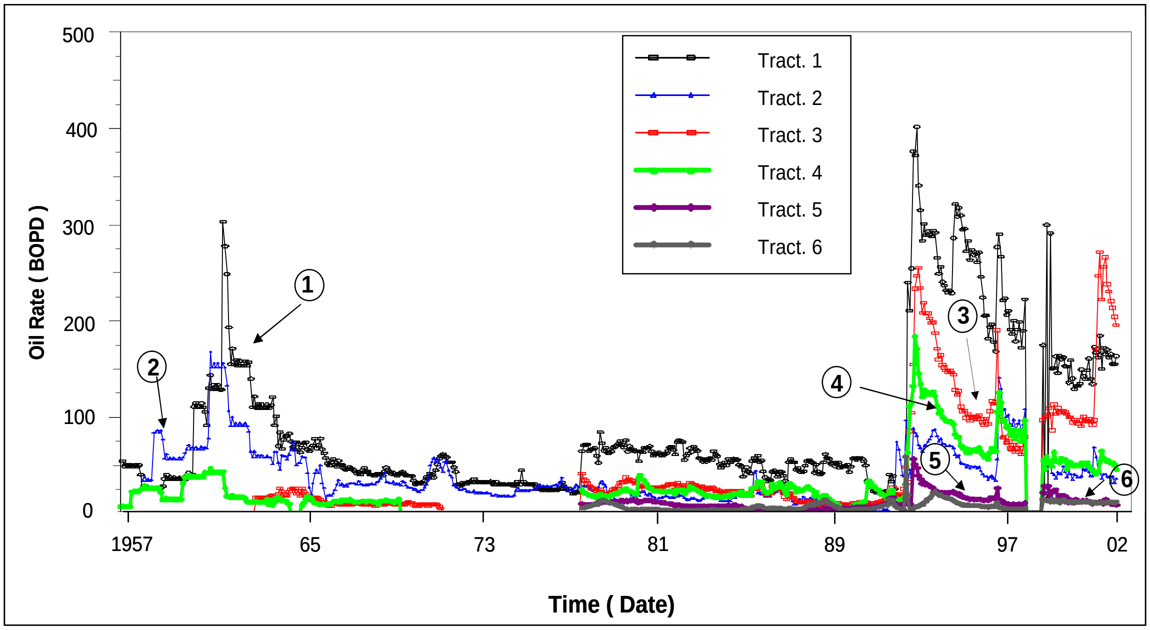

Fig.3. 35-Historical Oil Rate for Different Tracts of Germania Spraberry Unit.

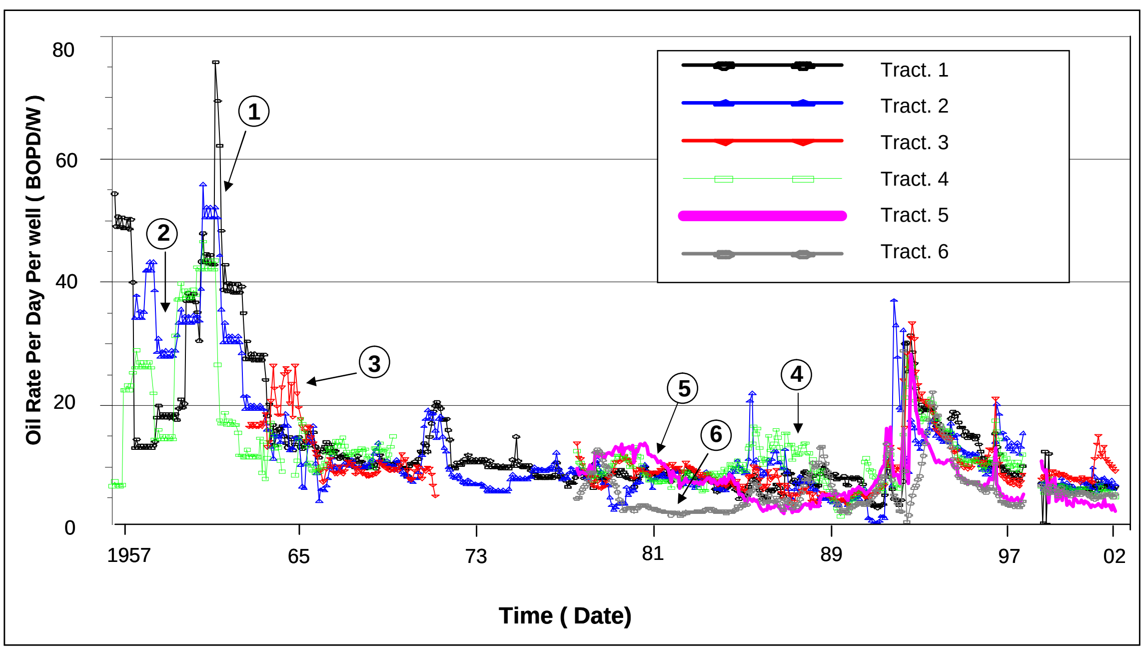

Fig.3. 36-Historical Oil Rate per well for Different Tracts of Germania Spraberry Unit.

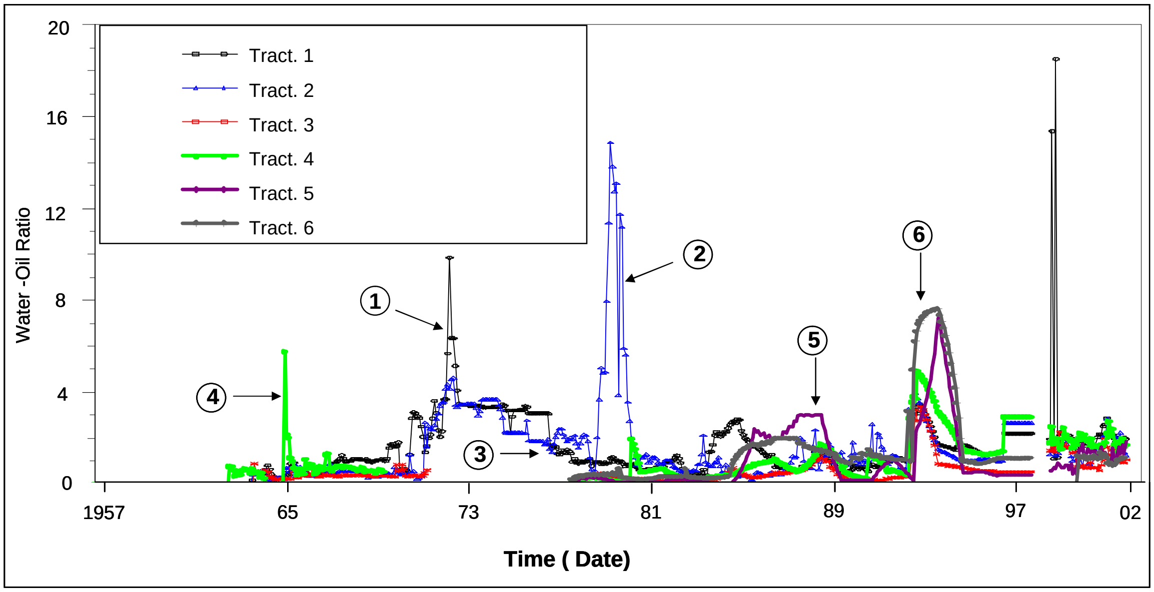

Fig.3. 37-Historical Water-Oil Ratio for Different Tracts of Germania Spraberry Unit.

Table 3. 6 Oil Recovery for Different Tracts of Germania Spraberry Unit.

Tract.	Area (Acres)	No. of Wells (Producers)	Cum. Oil Production (Before Waterflooding) (MMBbls)	Cum. Oil Production (After Waterflooding) (MMBbls)	Total Oil Cum. (MMBbls)	Cum. Oil Per Acre (Bbls)
1	1874	40	0.263	1.172	1.435	765
2	663	15	0.197	0.425	0.622	938
3	1345	27	0.014	0.565	0.579	430
4	663	14	0.063	0.383	0.446	673
5	166	3	0.000	0.098	0.098	590
6	166	3	0.000	0.062	0.062	374
Total	4877		0.537	2.705	3.242	

3.6 Well Performance Monitoring System.

The monitoring system was designed to systematically develop a comprehensive picture of how each well is performing. Several tools are used and combined to understand the performance of the wells in the unit for evaluating trends and identifying anomalies in some of them. The performance plots are generated for each well then analyzed individually and as a group to develop a complete picture of each performance.

After a potential problem is identified, the potential increase in production through remedial action is estimated. Wells that do not show signs of anomalies should be left to produce uninterrupted, but continue to be monitored on a monthly basis using the type of plots shown in this study. These are customized plots developed for routine performance monitoring of oil wells and can be used by operation personnel responsible for the day to day operation and maintenance of Germania Spraberry Unit.

This study presents a methodology which can be used to quickly evaluate and diagnose mechanisms and represents an effective tool for the selection of water control treatment and workover candidates. It mainly uses plots generated from available production history data.These plots can be automatically generated using the database and variables constructed in Oil Field Manager (OFM) for Germania Spraberry Unit.
A description of each type of plot constructed is given below.

3.6.1 Water Control Diagnostic Plots

Based on numerical simulation studies on reservoir water coning and channeling, it was discovery that log-log plots of water-oil ratio vs. time show different characteristic trends for different mechanisms. The time derivatives of WOR were found to be capable of differentiating whether the well is experiencing water coning, high permeability layer breakthrough or near wellbore channeling[3.] The desire to define different type of excessive water production problems has always been an important issue in Germania Spraberry Unit because in this area many wells have been pre-maturely abandoned as a result of very high water production (due to normal displacement of the water being injected) or casing failures (due to the corrosive nature of San Andreas water). In general, there are three basic classifications of the problems. Water coning, multilayer channeling and near wellbore problems are the most noticeable among others[6].

Very often, a near wellbore problem could suddenly occur during a normal displacement and production[6]. **Figs. 3.38**, **3.39, 3.40, 3.41, 3.42, 3.43, 3.44,** and **3.45** show the typical behavior for wells experiencing near wellbore water channeling. In all these wells, the initial WOR was constant and above 1.The WOR rapidly increased and followed a linear slope after the implementation of the waterflood. Then, the WOR increased and the slope went above 100.

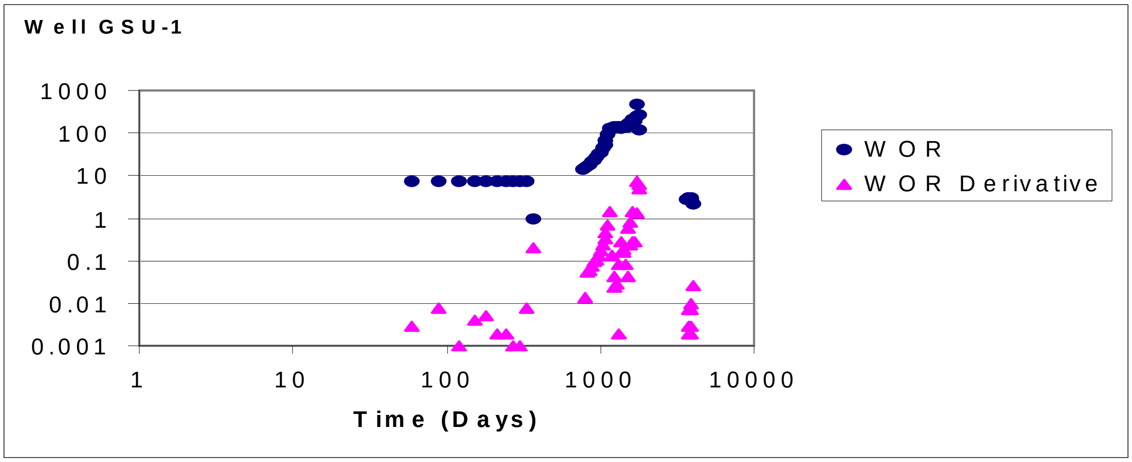

Fig.3. 38-WOR and WOR Derivative for well GSU-1: Experiencing Near Wellbore Water Channeling.

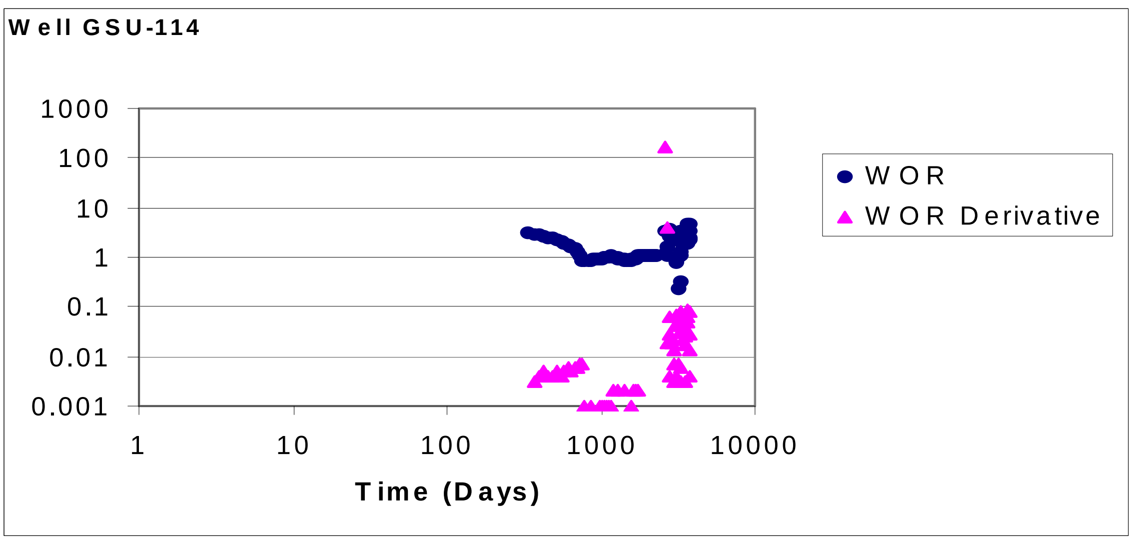

Fig.3. 39-WOR and WOR Derivative for well GSU-114: Experiencing Near Wellbore Water Channeling.

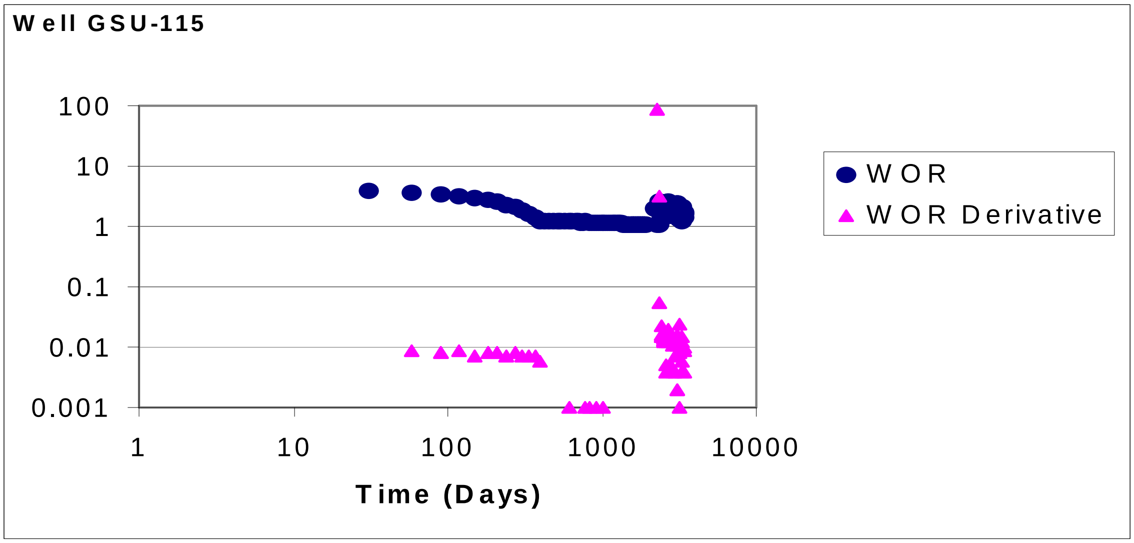

Fig.3. 40-WOR and WOR Derivative for well GSU-115: Experiencing Near Wellbore Water Channeling.

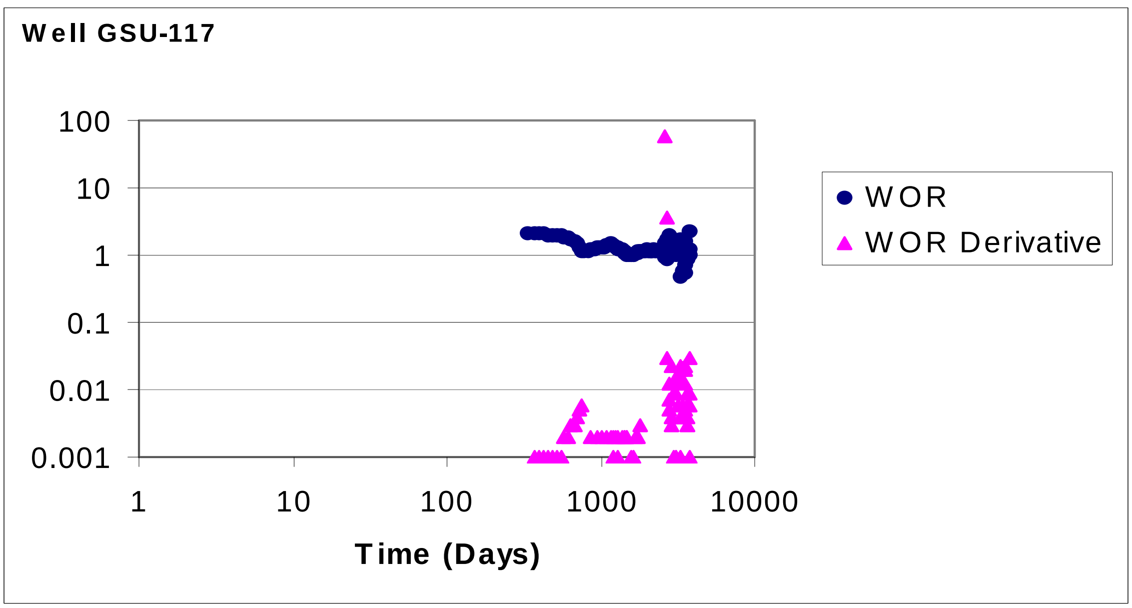

Fig.3. 41-WOR and WOR Derivative for well GSU-117: Experiencing Near Wellbore Water Channeling.

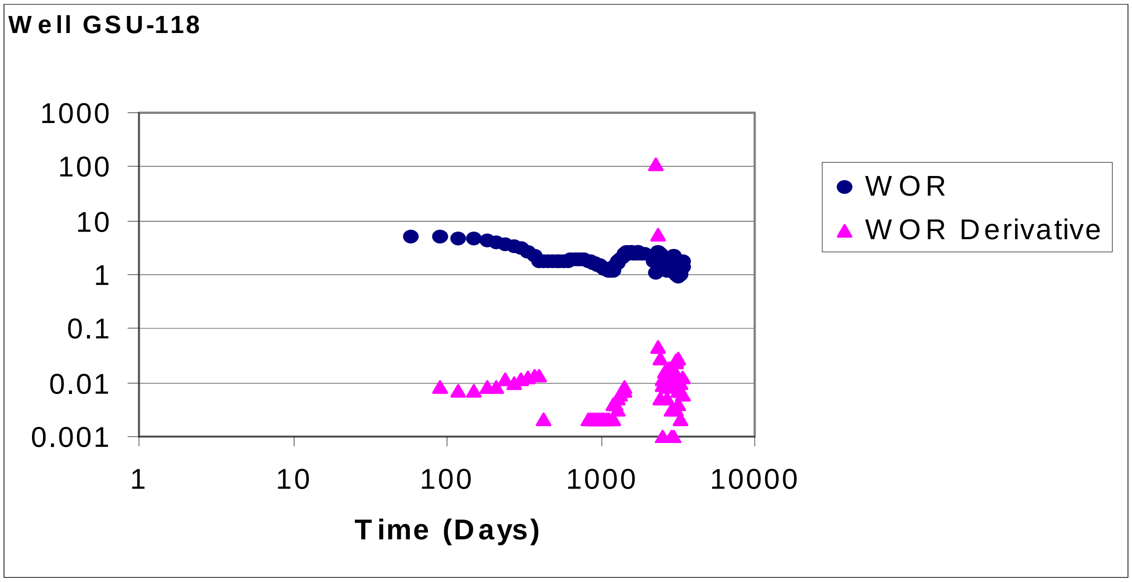

Fig.3. 42-WOR and WOR Derivative for well GSU-118: Experiencing Near Wellbore Water Channeling.

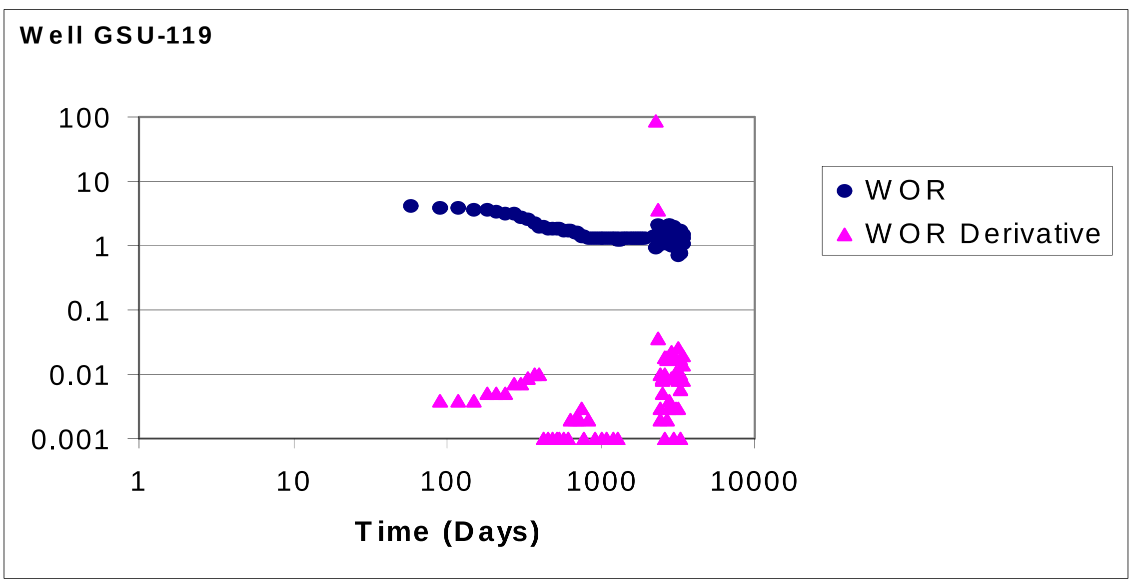

Fig.3. 43-WOR and WOR Derivative for well GSU-119: Experiencing Near Wellbore Water Channeling

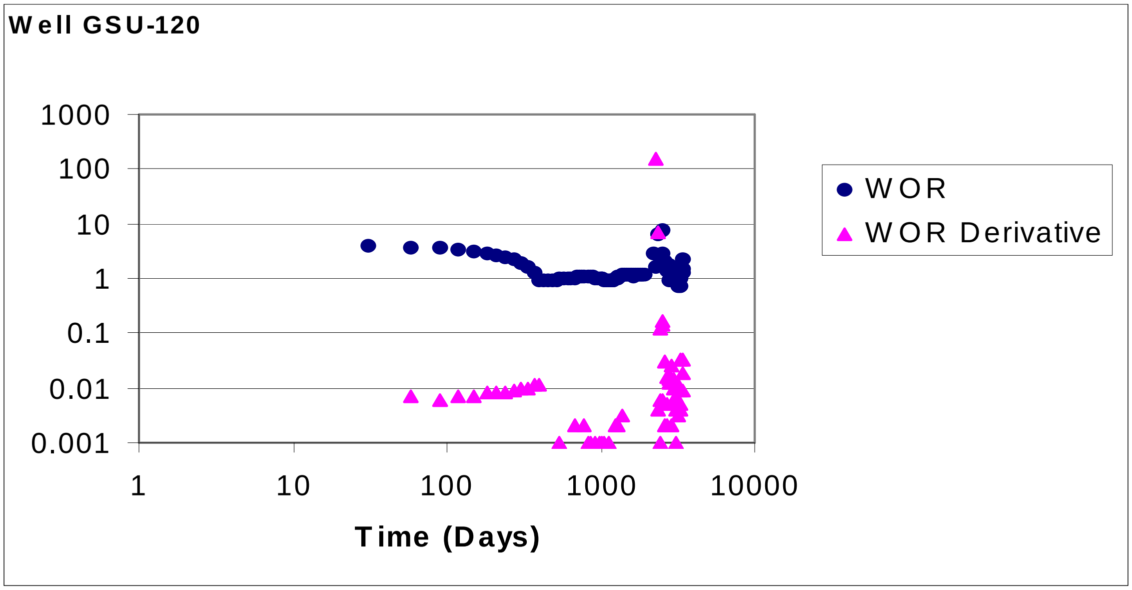

Fig.3. 44-WOR and WOR Derivative for well GSU-120: Experiencing Near Wellbore Water Channeling

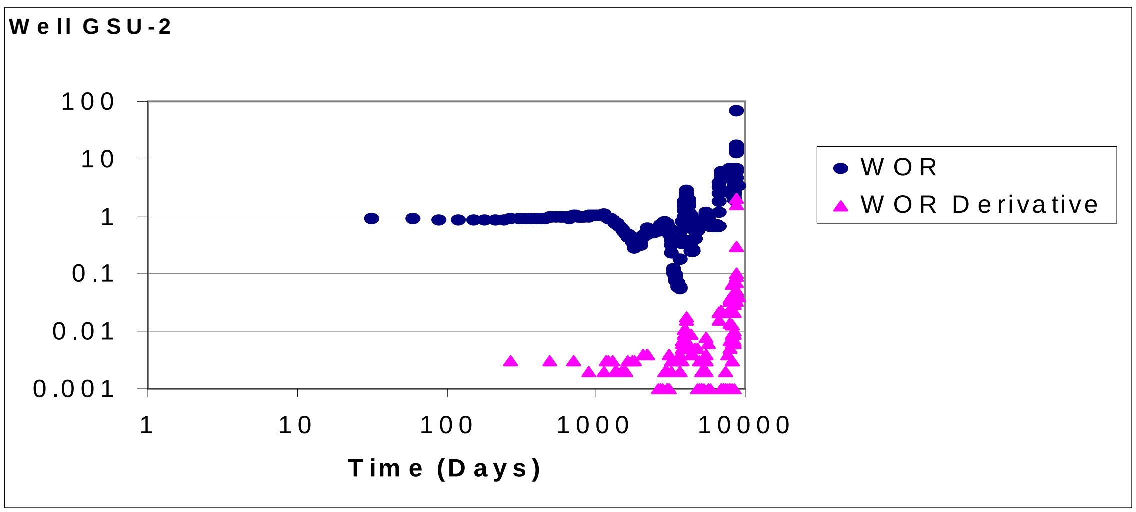

Fig.3. 45-WOR and WOR Derivative for well GSU-2: Experiencing Near Wellbore Water Channeling.

Figs.3.46 and **3.47** show the typical behavior for wells experiencing bottom water coning with late time channeling behavior. In all these wells, the WOR shows a nearly constant positive slope and WOR Derivative change its slope from negative to positive.

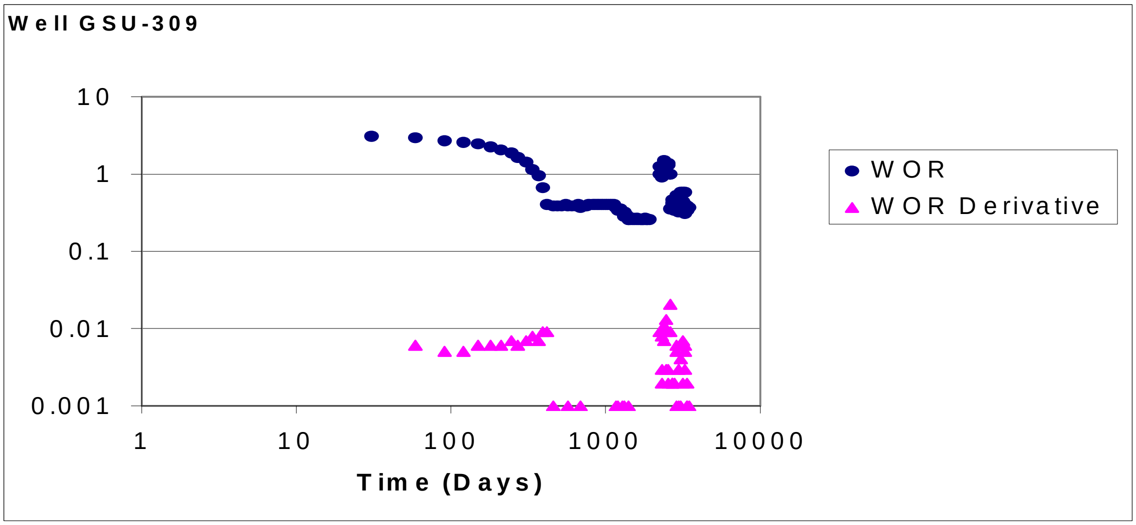

Fig.3. 46-WOR and WOR Derivative for well GSU-309: Experiencing Bottom Water Coning with Late Time Channeling.

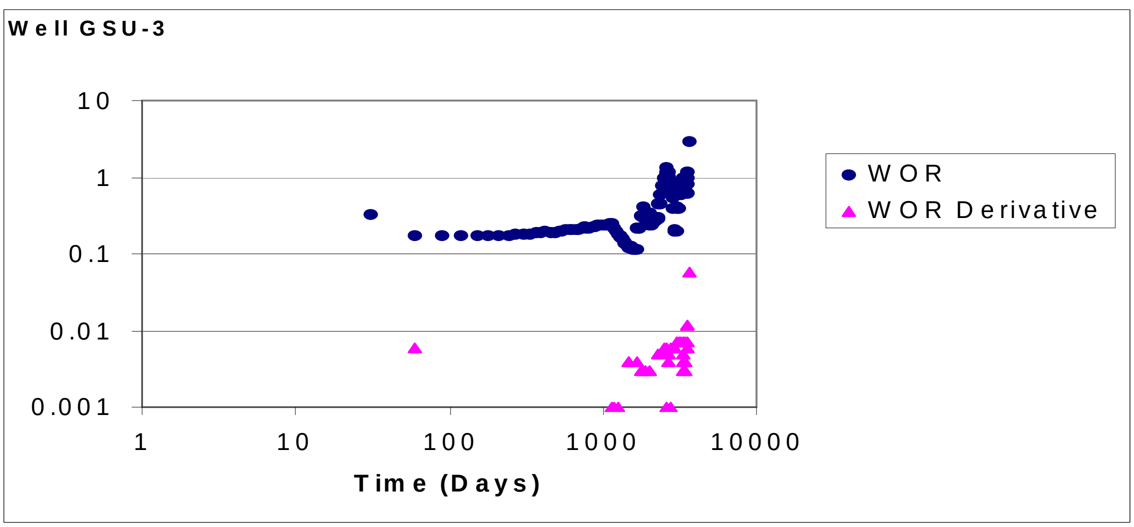

Fig.3. 47-WOR and WOR Derivative for well GSU-3: Experiencing Bottom Water Coning with Late Time Channeling.

Figs.3.48, 3.49, 3.50, 3.51, 3.52, 3.53, and **3.54** show the typical behavior for wells experiencing rapid channeling (perhaps associated to high permeability channels or fractures). In all these wells, both the WOR and its derivative show a drastic increment from the very beginning of the production life.

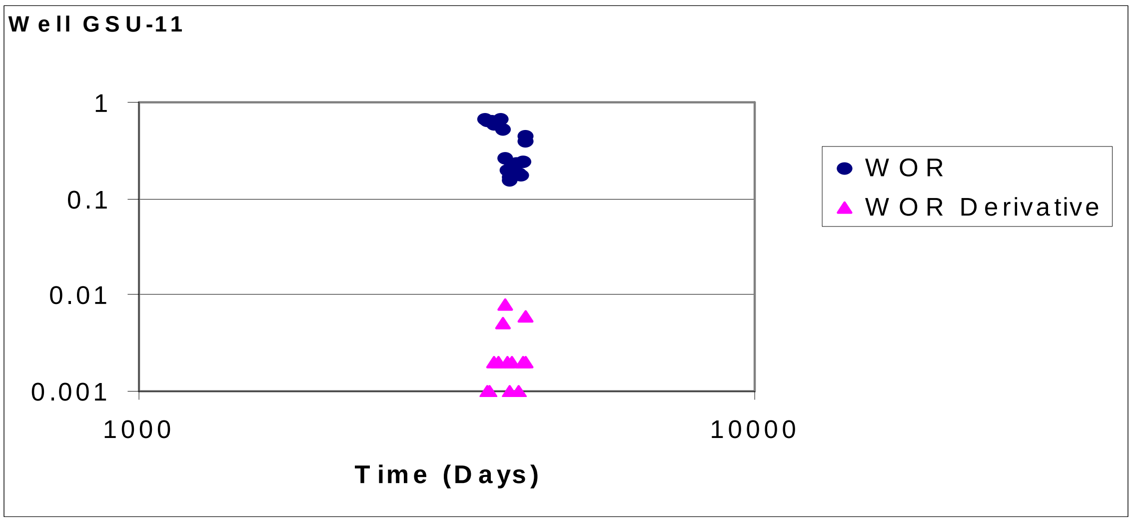

Fig.3. 48-WOR and WOR Derivative for well GSU-11: Experiencing Rapid Channeling.

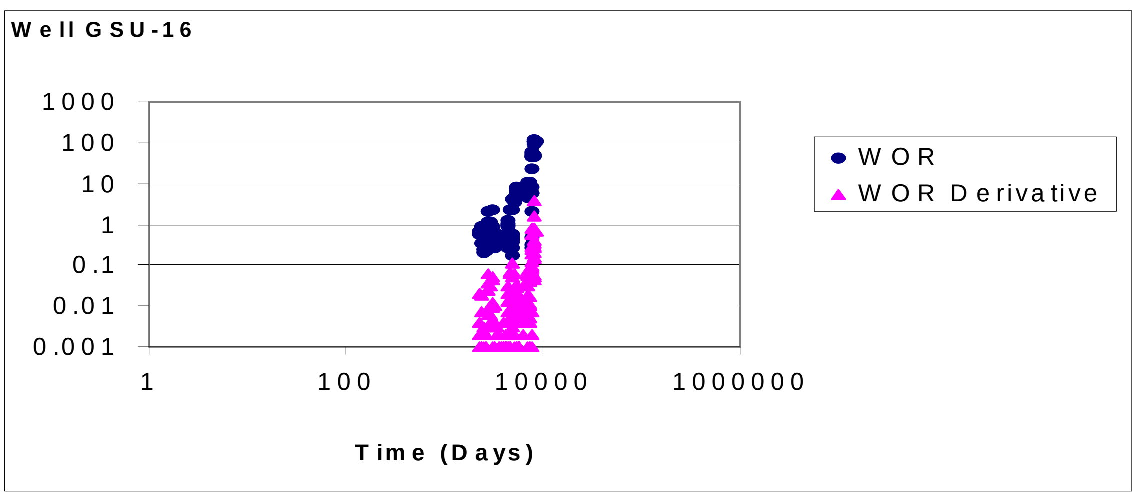

Fig.3. 49-WOR and WOR Derivative for well GSU-16: Experiencing Rapid Channeling.

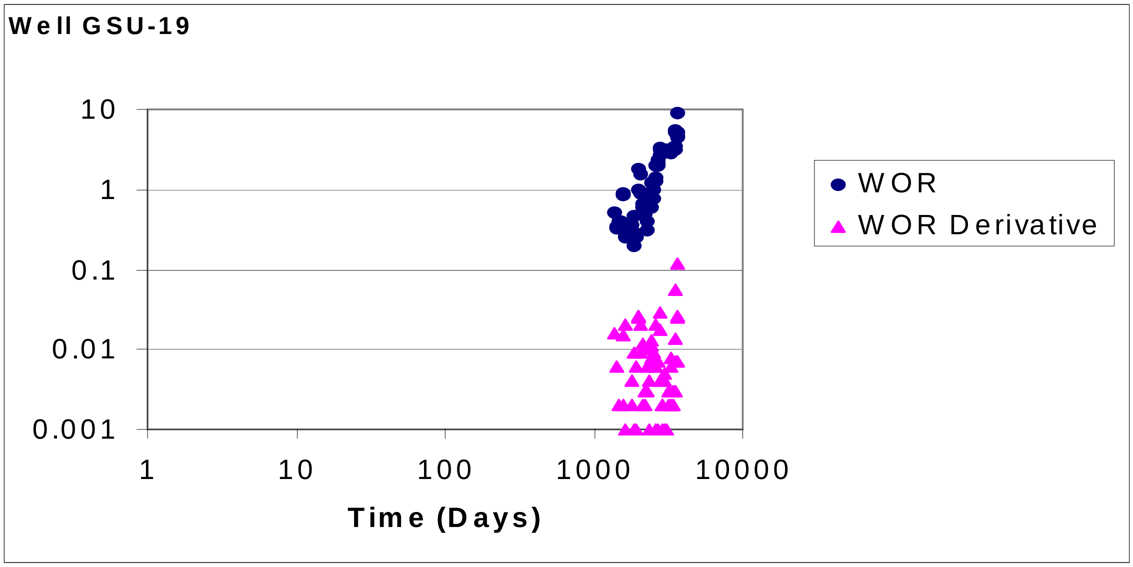

Fig.3. 50-WOR and WOR Derivative for well GSU-16: Experiencing Rapid Channeling.

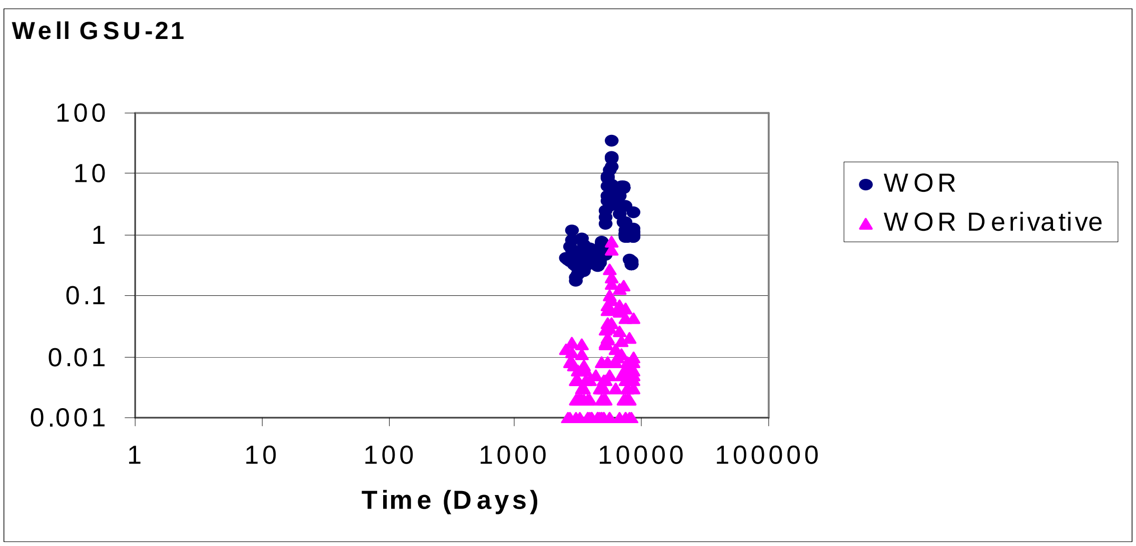

Fig.3. 51-WOR and WOR Derivative for well GSU-21: Experiencing Rapid Channeling.

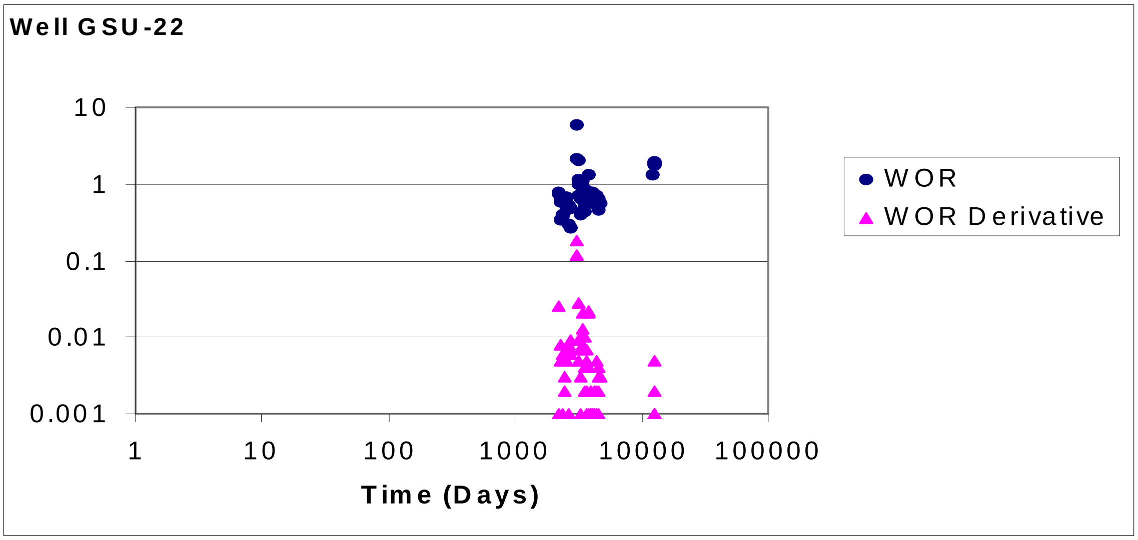

Fig.3. 52-WOR and WOR Derivative for well GSU-22: Experiencing Rapid Channeling

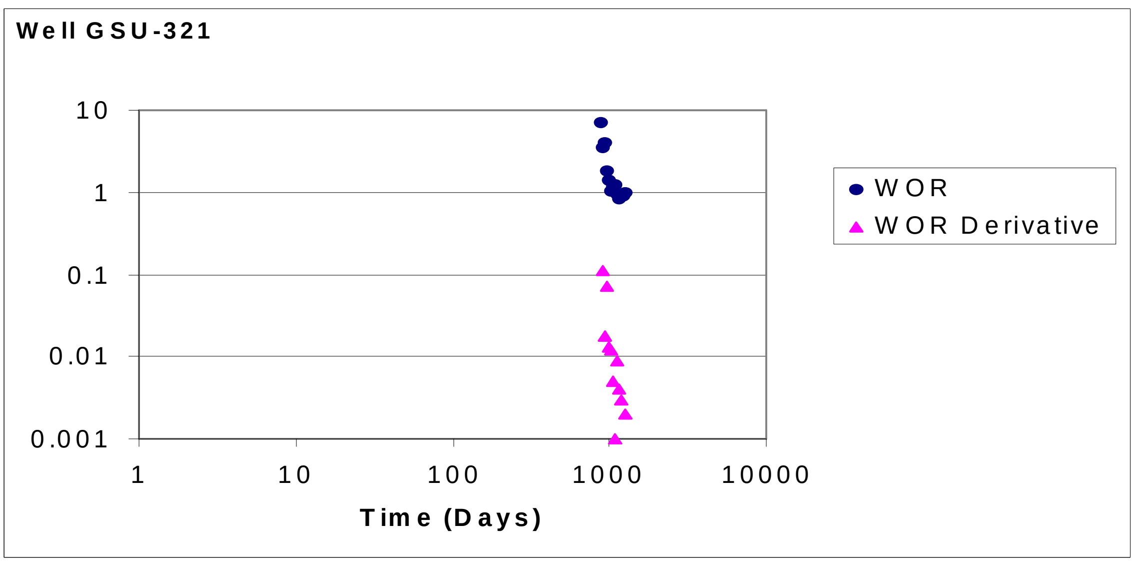

Fig.3. 53-WOR and WOR Derivative for well GSU-321: Experiencing Rapid Channeling.

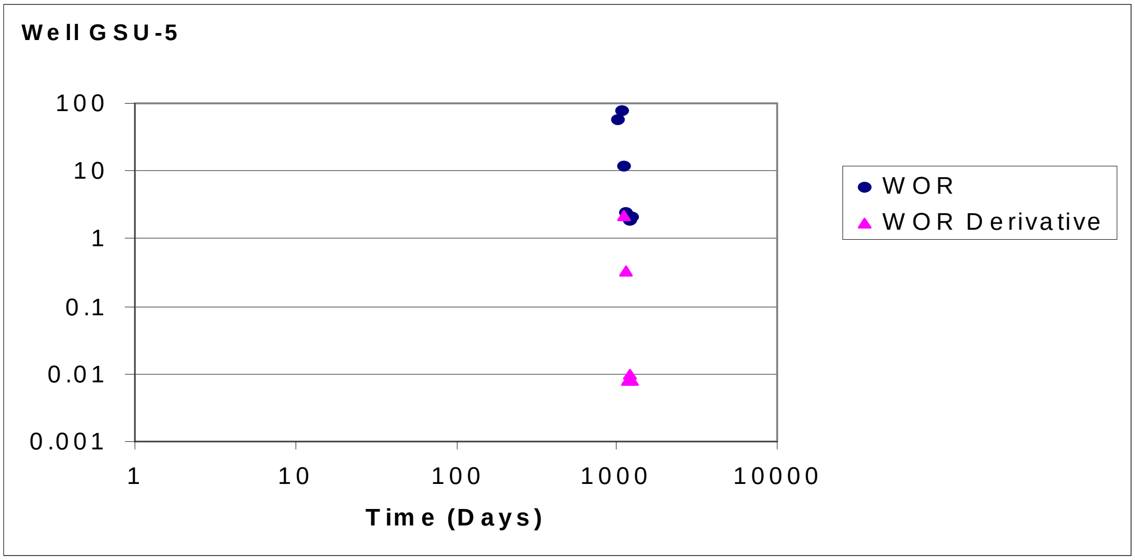

Fig.3. 54-WOR and WOR Derivative for well GSU-5: Experiencing Rapid Channeling.

Figs.3.55, 3.56, 3.57, 3.58, 3.59, 3.60, 3.61, and **3.62** show the pattern for wells experiencing normal displacement with high WOR. In all these wells, both the WOR and the WOR derivative change their slope and are mostly scattered throughout the production life.

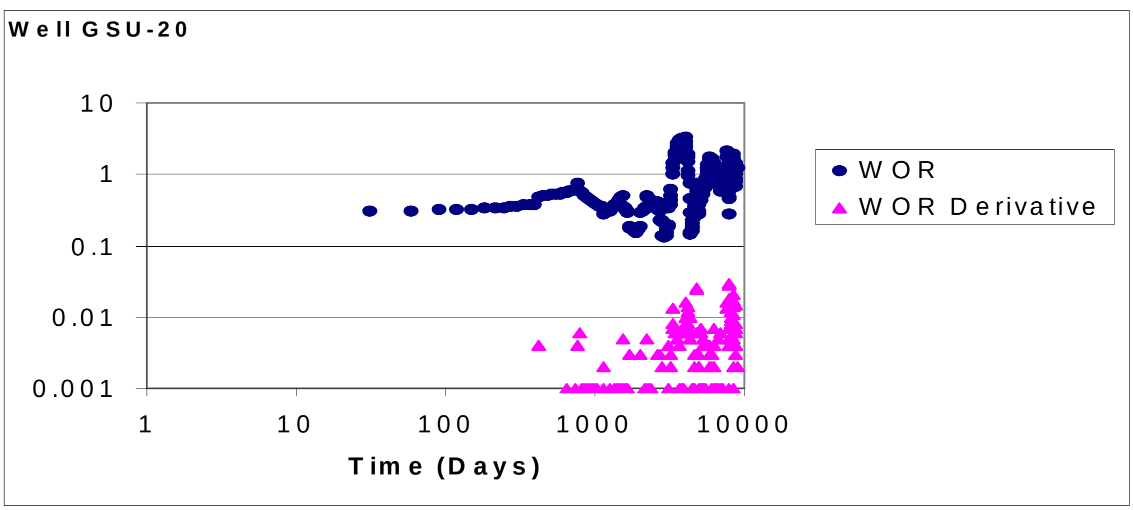

Fig.3. 55-WOR and WOR Derivative for well GSU-20: Experiencing Normal Displacement with High WOR.

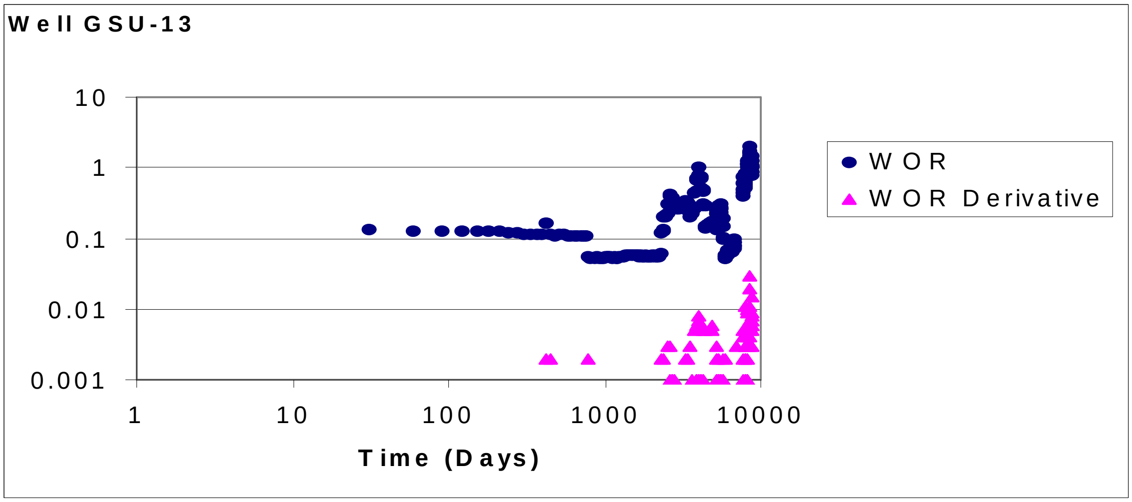

Fig.3. 56-WOR and WOR Derivative for well GSU-13: Experiencing Normal Displacement with High WOR.

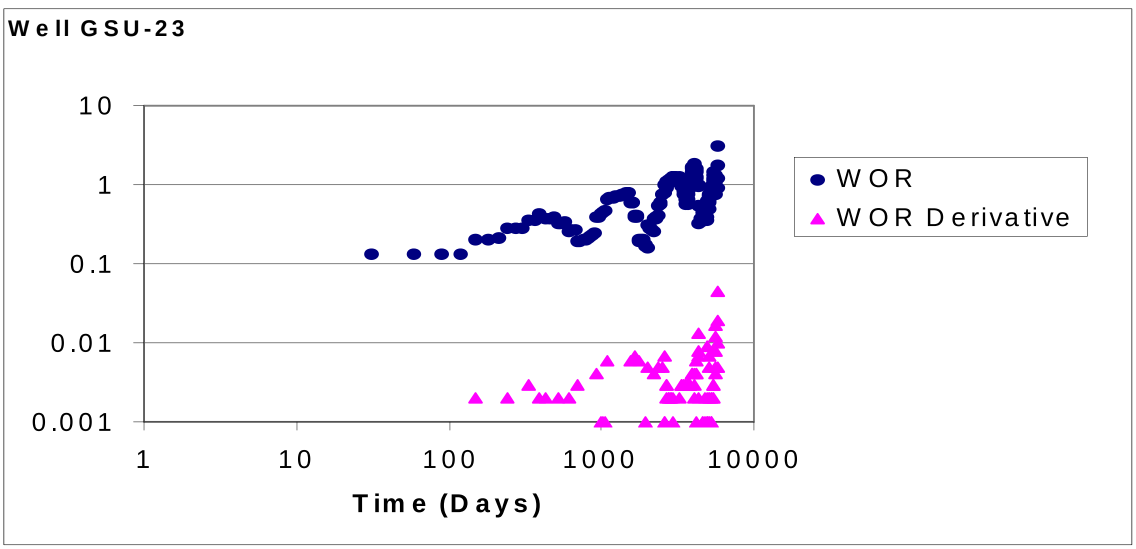

Fig.3. 57-WOR and WOR Derivative for well GSU-23: Experiencing Normal Displacement with High WOR.

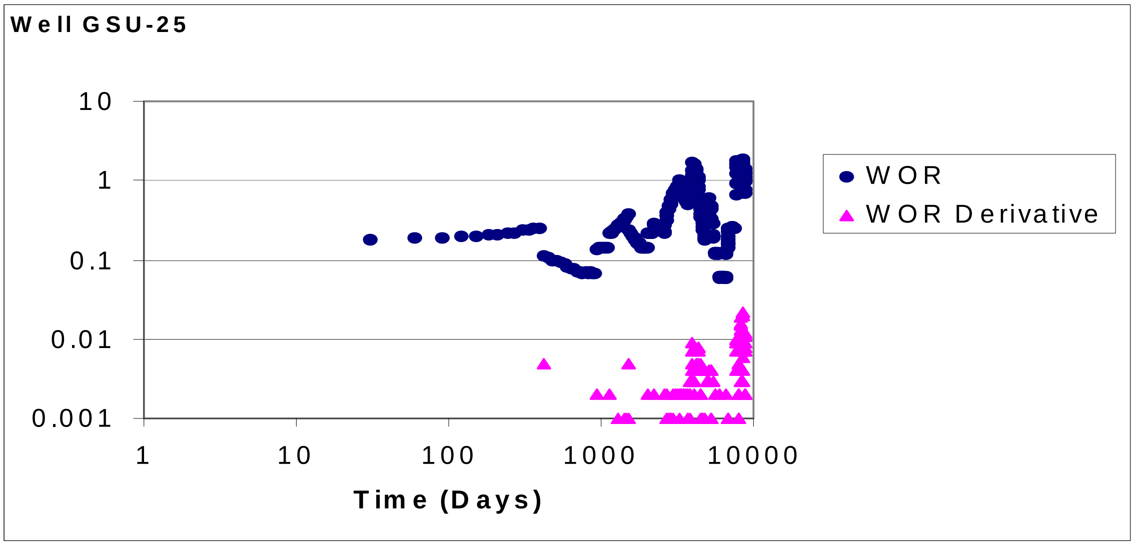

Fig.3. 58-WOR and WOR Derivative for well GSU-25: Experiencing Normal Displacement with High WOR.

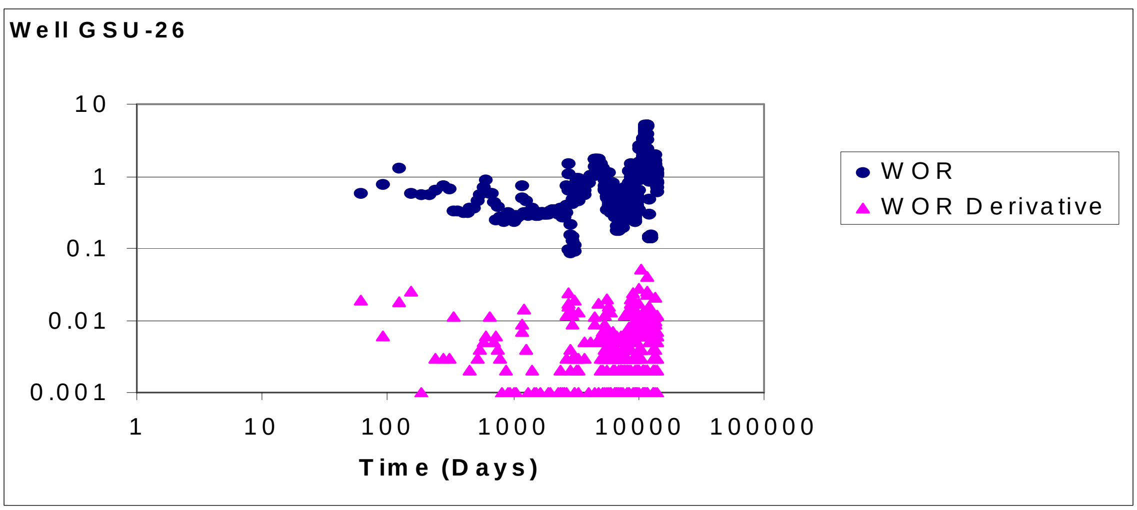

Fig.3. 59-WOR and WOR Derivative for well GSU-26: Experiencing Normal Displacement with High WOR.

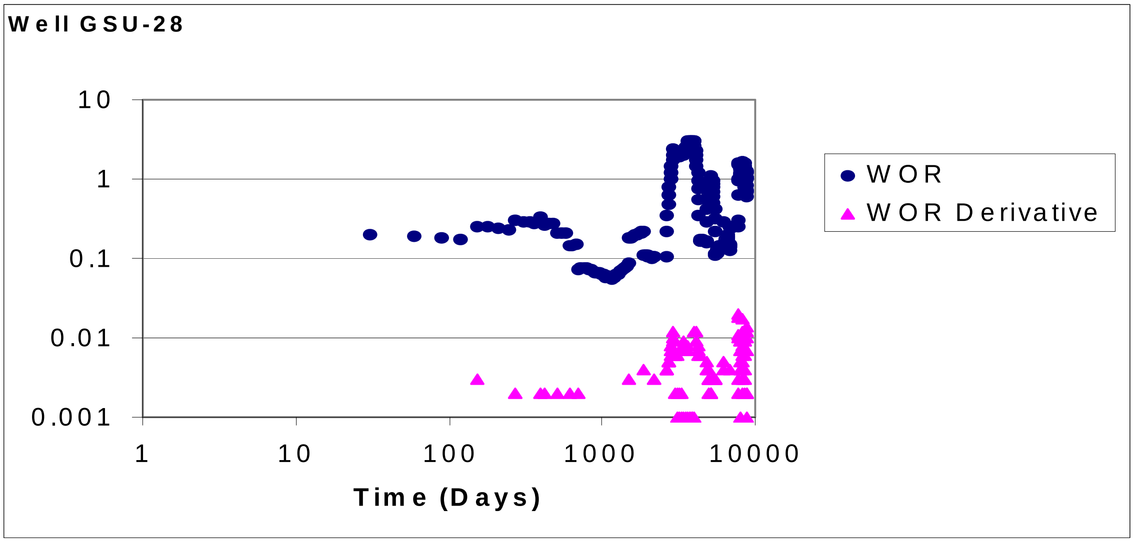

Fig.3. 60-WOR and WOR Derivative for well GSU-28: Experiencing Normal Displacement with High WOR.

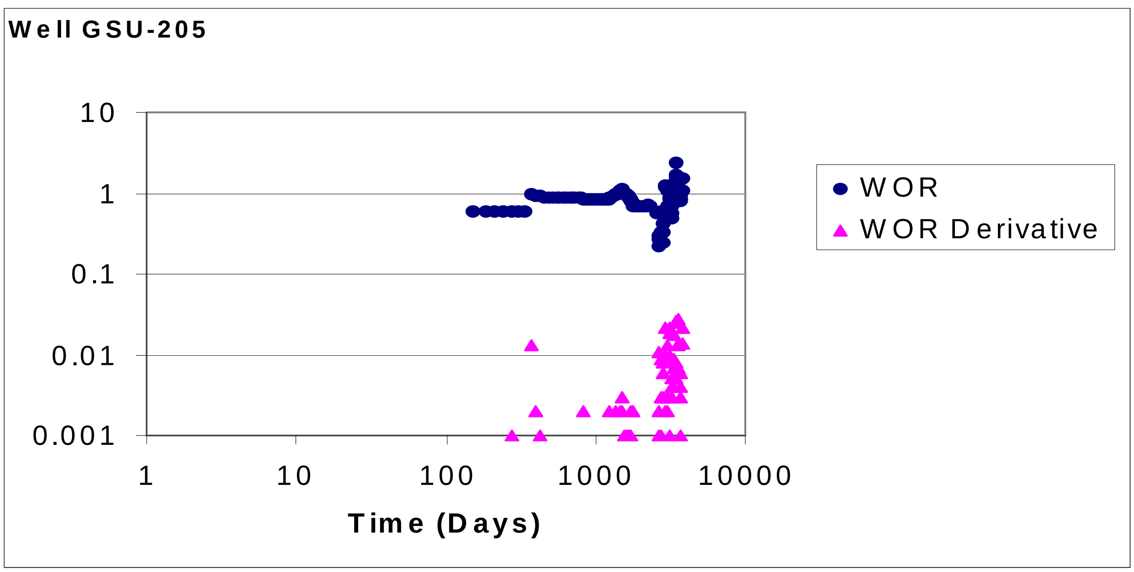

Fig.3. 61-WOR and WOR Derivative for well GSU-205: Experiencing Normal Displacement with High WOR.

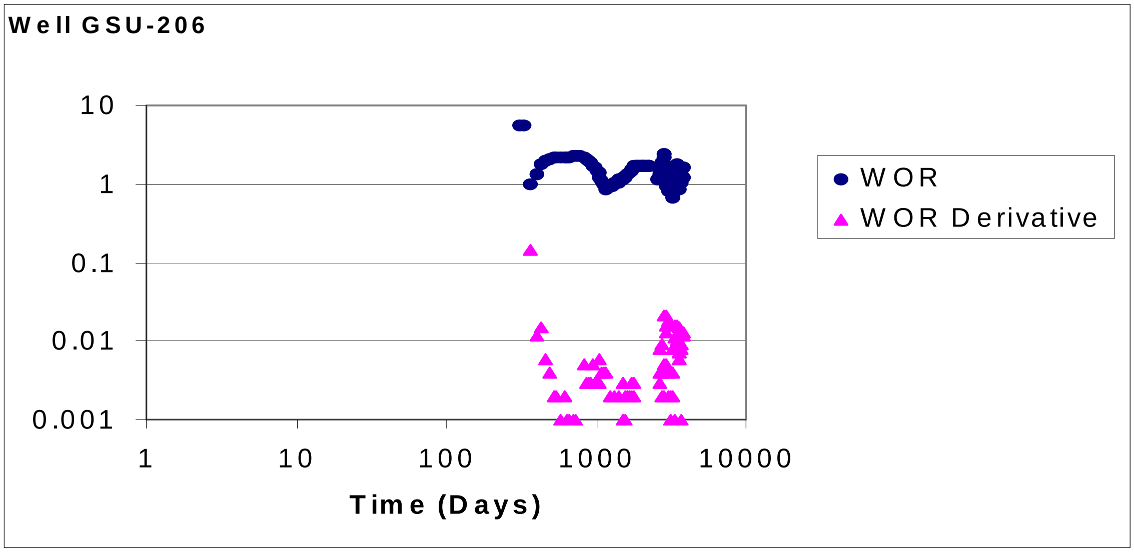

Fig.3. 62-WOR and WOR Derivative for well GSU-206: Experiencing Normal Displacement with High WOR.

Table 3.7 summarizes the results and the diagnostic of wells analyzed using Water Control Diagnostic Plots (log-log plots of WOR vs. time and WOR derivative vs. time).

Table 3. 7 Summary from Water Control Diagnostic Plots for wells in Germania Spraberry Unit.

Wells	Diagnostic	Remarks
GSU-1, GSU-114, GSU-115, GSU-117, GSU-118, GSU-119, GSU-120, GSU-10	Near Wellbore Channeling	Well GSU-1 may have casing leak
GSU-309, GSU-3	Botton Water coning with late time channeling	Well GSU-3 Plugged and Abandoned Well GSU-309 Active
GSU-11, GSU-16, GSU-19, GSU-21, GSU-22, GSU-321, GSU-5	Rapid Channeling	Well GSU-5 may have casing leak Wells may be associated to fractures
GSU-20, GSU-13, GSU-23, GSU-25, GSU-26, GSU-28, GSU-205, GSU-206	Normal displacement with high WOR	Wells located in areas with high water saturation

3.6.2 Scatter Plots

Another type of plot used in this study for well performance monitoring system is a kind of plot called Scatter Plot. Scatter plot provides another tool available in Oil Field Manager (OFM) for analyzing multiple variables at the same time and their interactions over time. Besides being a mapping tool, Scatter Plot is also a plotting tool that has the capability of presenting any combination of variables on the two axes[5].

For monitoring, we used this strong analytical tool by plotting the cumulative oil vs. the cumulative water for all active wells (64 wells) in Germania Spraberry Unit and following the track for every well to detect some deviations respect to the normal behavior.

Fig.3.63 shows the scatter plot for all active wells producing in Germania Spraberry Unit. Well GSU-26 has been an excellent well because has been the one with the most cumulative (159,000 barrels of oil and 106,000 barrels of water) and has always maintained the same slope. This is a good well to select the best practice of completion in the area. Well GSU- 2, was producing with an almost constant slope and then, after a cumulative oil production of 60,000 barrels of oil, the water production suddenly increased indicating that the breakthrough in this well occurred after 60,000 barrels of oil produced or the flood front reached the perforation of the well. Well GSU-409 has produced only 31,000 barrels of oil and 143,000 barrels; this is indicative of either channeling or highly drained area around this well. The water production could increase in this well because it is located in front of two injection wells (GSU-407 and GSU-22).Well GSU-13 and 25 constitute two good wells because have maintained a very low slope in the plot (this means they produce at a high rate of oil respect to the rate of water).

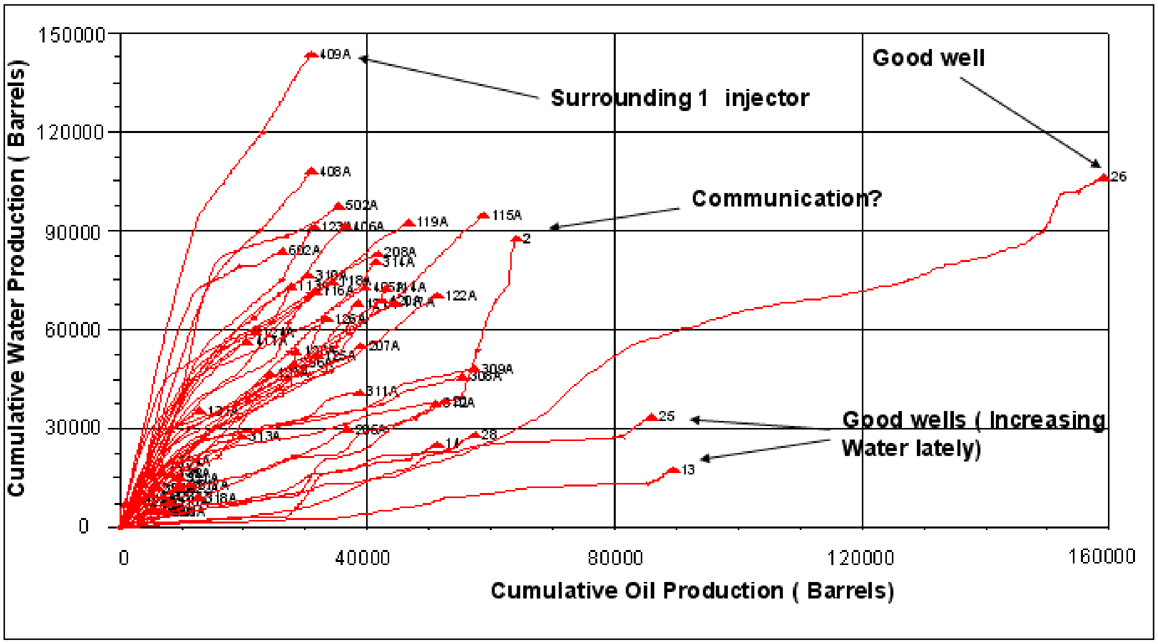

Fig.3. 63-Scatter plot showing the performance of Cumulative Oil vs. Cumulative Water for active wells in Germania Spraberry Unit.

3.7 Flood Front Maps and Bypassed Oil.

Flood front maps are a pictorial display showing the location of various food fronts. The maps, often called "bubble maps," allow visual differentiation between areas of the reservoir that have and have not been swept by injected water[6] and were generated using the module GRID in Oil Field manager. These maps are very useful to identify areas with little or no water (bypassed oil).The generation of these maps is based on interpolation techniques (ordinary Kriging). In this study these kinds of maps were used with the aim of evaluating, the water, oil, and gas distribution and the fluid fronts as a function of time. Since this representation is a snap shot in time, this particular views allowed determination either visually or numerically of the cumulative fluids in a any part of the reservoir and therefore help to keep track of the flood fronts in the area.

Fig 3.64 shows bubble maps of cumulative oil for different times and stages of depletion of Germania Spraberry Unit. In the bubble maps, we can see that most of the production has taken place around the injectors (GSU-11, GSU-19, GSU-22, GSU-27 and GSU-6). The dark spots in the maps suggest areas with response to the injection and therefore the most drained areas of the unit. According to this bubble map, the central part of the unit is the most depleted.

Fig 3.65 shows bubble maps of cumulative oil at last date (2002). In the bubble maps, we can see that most of the production has taken place in the wells GSU-21, GSU-26, GSU-16, GSU-10, and GSU-12. This map can be used as a reference to locate infill drilling wells in the areas with little or no oil production.

Areas in which wells have cumulative oil production (from 1957 to 2002) greater than 80,000 barrels (**Fig 3.65**) generally correspond to areas of greater net pay in the operational units 1U and 5U. Areas of highest cumulative production ("sweet spots") are in the north-central part of the waterflood unit, where ten wells have each produced between 70,000 and 159,000 barrels of oil. This map also suggests an influence of reservoir stratigraphy and fracture trend on oil production. Areas having the best oil-producing wells ("sweet spots") and their adjacent water injection wells formed trends parallel to the main set of natural fractures (N 56^{o} E) and are also correlative with axes of maximum net pay.

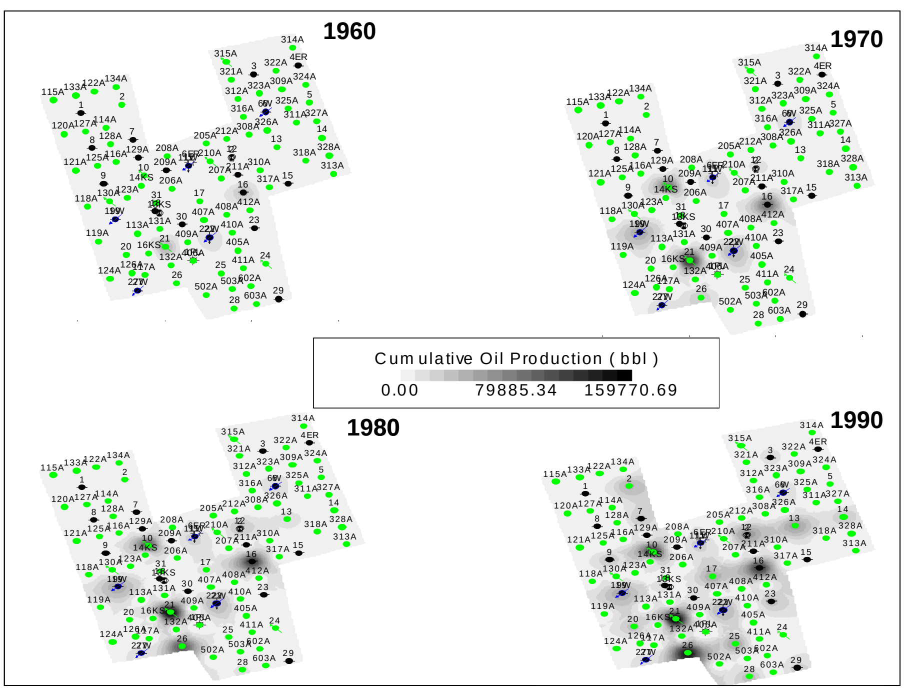

Fig.3. 64-Bubble Maps for different periods of exploitation in Germania Spraberry

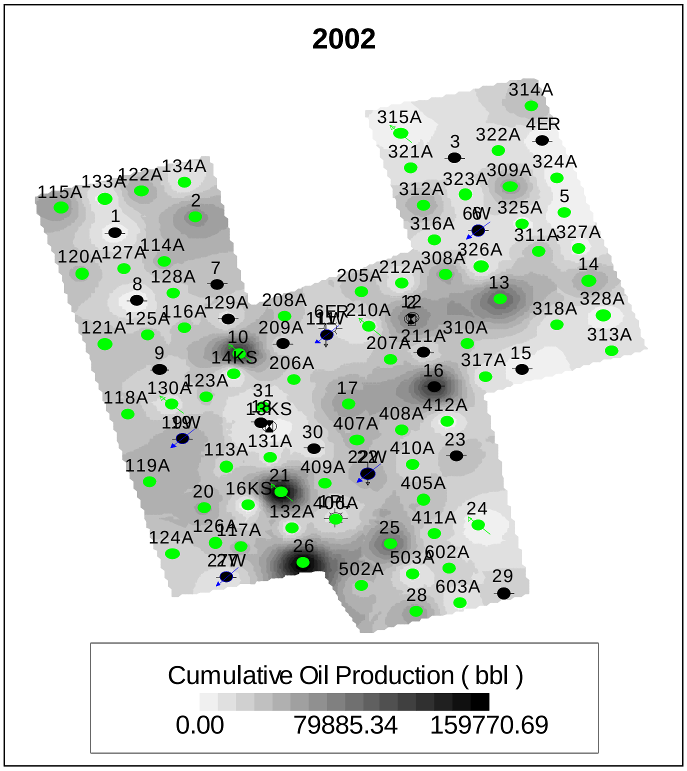

Fig.3. 65-Bubble Maps of Cumulative Oil Production in Germania Spraberry.

Fig 3.66 shows bubble maps of cumulative water production for different stages of depletion. In the bubble maps, we can see that most of the production (areas represented by dark spots) has taken place in the wells GSU-21, GSU-26, GSU-16, GSU-10, and GSU-12. This map can also be used as a reference to locate infill drilling wells in the areas with little or no water production (areas represented by the light spots in bubble map at last date (year 2002)). These maps also show correlation between the cumulative water production and the main fracture trend.

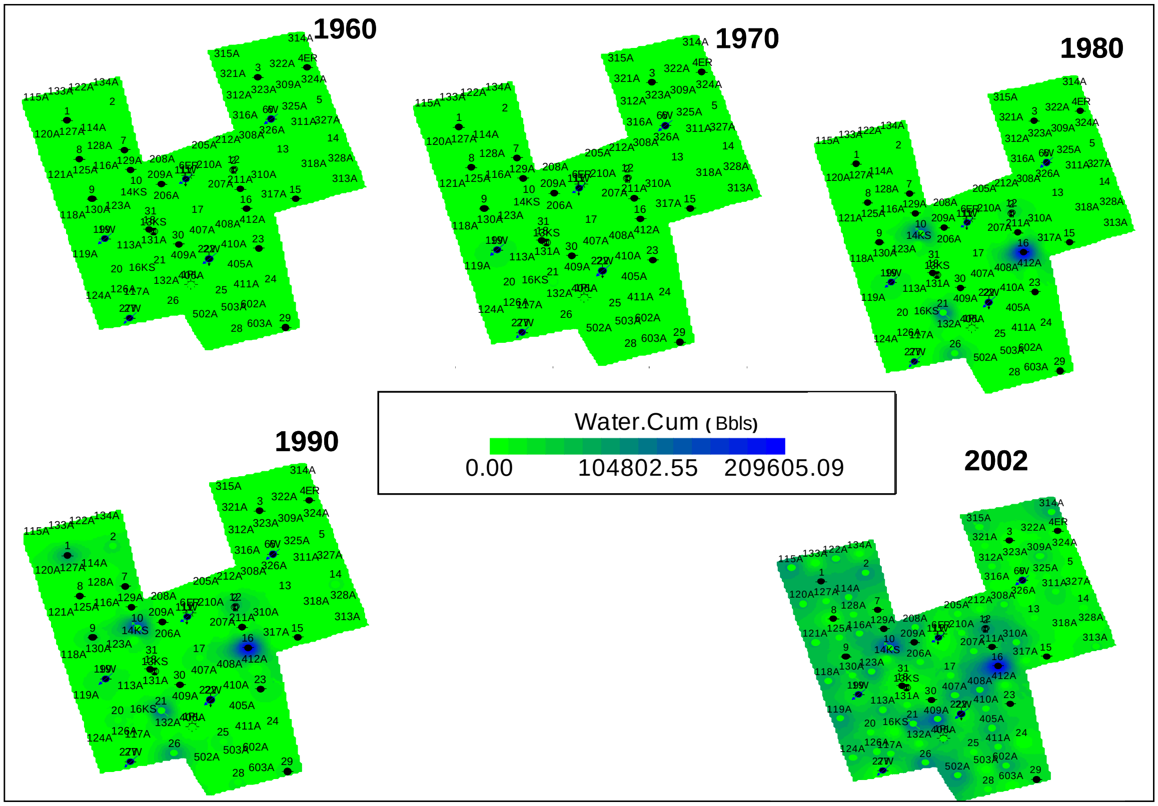

Fig.3. 66 - Bubble Maps of Cumulative Water Production in Germania Spraberry.

Fig 3.67 shows bubble maps of cumulative gas production for different stages of depletion In the bubble maps, we can see that most of the production has taken place in the wells GSU-21, GSU-26, GSU-16, GSU-10, and GSU-12. These maps also show correlation between the cumulative water production and the main fracture orientation.

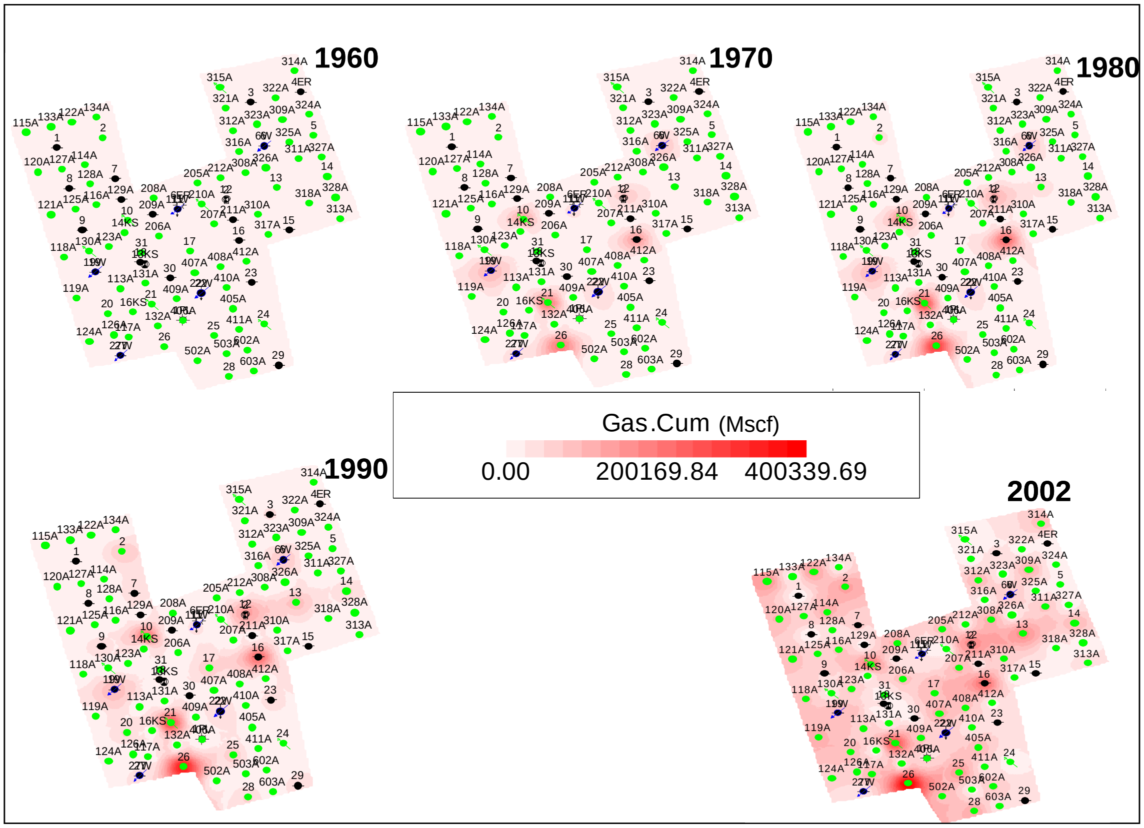

Fig.3. 67 - Bubble Maps of Cumulative Gas Production in Germania Spraberry.

IV. Production Forecast and Reserve Estimation

A major activity in this project was to estimate the remaining reserves and its distribution in the reservoir for monitoring and identification of further development opportunities. In this case, since we have sufficient production data, we applied the most widely used method of forecasting future production (Decline Curve Analysis) to estimate the remaining reserves associated to drainage radius of every well and extrapolate the performance of the reservoir in the future.

Due to the nature of oil production rate from naturally fractured reservoirs, a hyperbolic type decline curve was used to fit the production trend and forecast the future production rate. We performed and extrapolated the future performance starting from the last production point available (June 2003) for all 64 active wells in the reservoir and then displayed the reserves (remaining reserves and estimated ultimate recovery (EUR)) in a bubble map, this helped us to identify some opportunities by locating the areas with the most remaining reserves in the reservoir (“sweet spots”).

The results show that under the current operation conditions (new injection pattern and water injection rate), the reservoir can produce 1.410 million barrels of oil additional (through the wells currently active) and increase the ultimate recovery up to 4.652 million barrels in the next 20 years. The results, also suggest that the areas with the most remaining reserves are those located in the north-east part of the unit.

The decline curve analysis was performed under the following premises:

- Hyperbolic type decline
- Economic Limit: 1 BOPD
- Time Limit: 20 years
- Fractional power exponential decline (b) = 0.7
- Starting Rate: Last oil rate in the data base for every well.
- Starting Date: Last Production Date (June 2003)

The equation used to perform the decline curve analysis in every active well is as follows:

$$q_t = q_i (1 + (a_i * bt))^{-(1/b)} \quad \text{...} (4.4)$$

Where:

q_t = producing rate at end of time t, BOPD.

q_i = initial rate at time t = 0, BOPD

a_i = constant of integration equal to the production decline rate as a fraction, fraction/year.

b = exponent of hyperbolic decline, Dimensionless.

t = time from start of analysis period, Years.

To estimate the remaining reserves for every well over the next 20 years, we integrated the equation 4.4 to obtain the following equation:

$$Np = \frac{q_i}{a_i (1 - b)} (1 - (1 + (a_i bt))^{(1-(1/b))}) \; 365 \quad \text{.......} (4.5)$$

Where:

Np = Cumulative production from start of the analysis period to the end of year "t", STB

q_i = initial rate at time t = 0, BOPD

a_i = constant of integration equal to the production decline rate as a fraction, fraction/year.

b = exponent of hyperbolic decline, Dimensionless.

t = time from start of analysis period, Years.

Fig 4.1, 4.2, 4.3, 4.4, 4.5, and 4.6 show the remaining reserves estimated with equation **4.5** for every well and its corresponding produced reserves (as of June 2003)

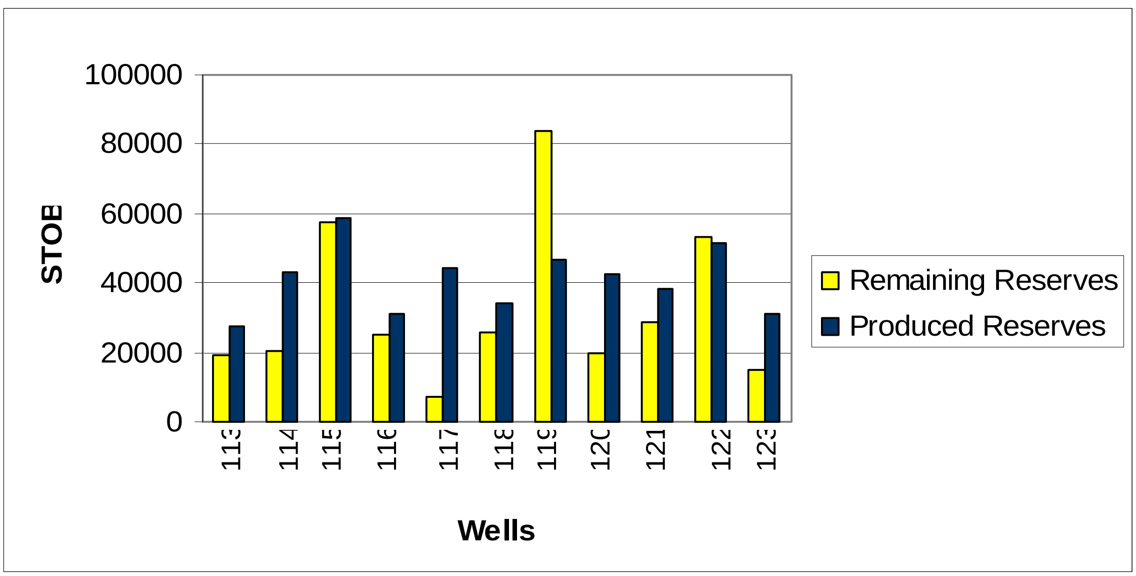

Fig.4. 1- Remaining and Produced Reserves for wells GSU-113,GSU-114,GSU-115,GSU-116,GSU-117,GSU-118,GSU-119,GSU-120,GSU-121,GSU-122, and GSU-122.

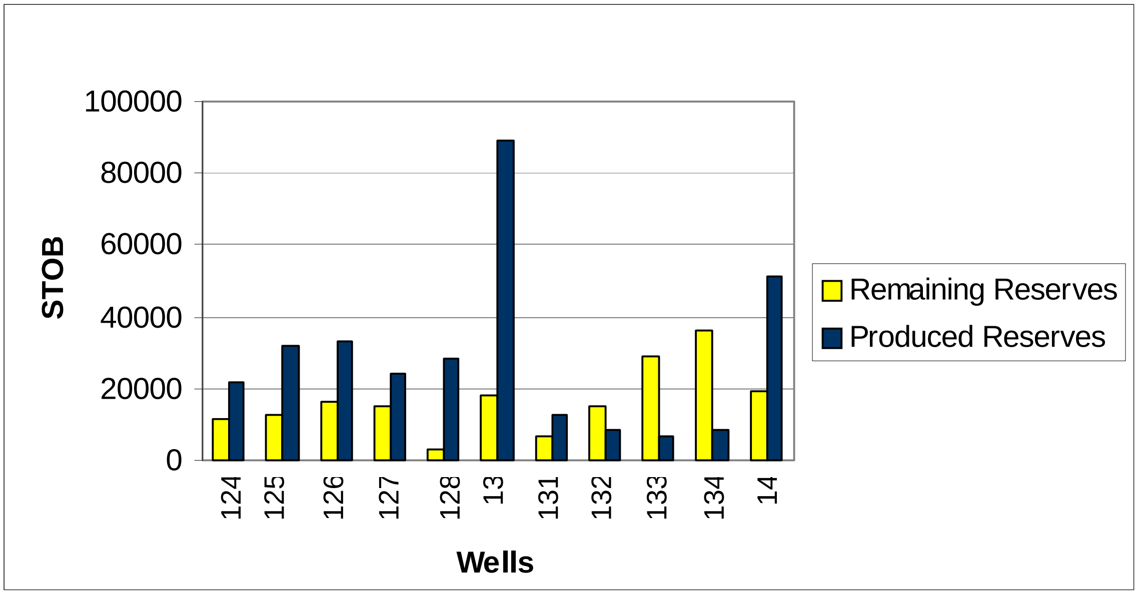

Fig.4. 2- Remaining and Produced Reserves for wells GSU-124,GSU-125,GSU-126,GSU-127,GSU-128,GSU-13,GSU-131,GSU-132,GSU-133,GSU-134, and GSU-14.

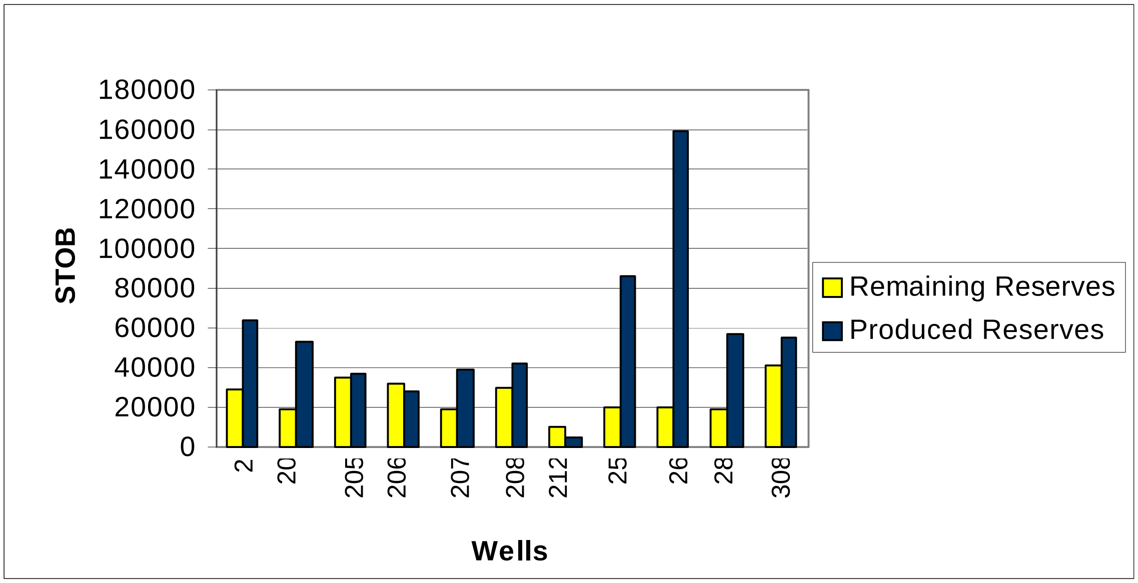

Fig.4. 3- Remaining and Produced Reserves for wells GSU-2,GSU-20,GSU-205,GSU-206,GSU-207,GSU-208,GSU-212,GSU-25,GSU-26,GSU-28, and GSU-308.

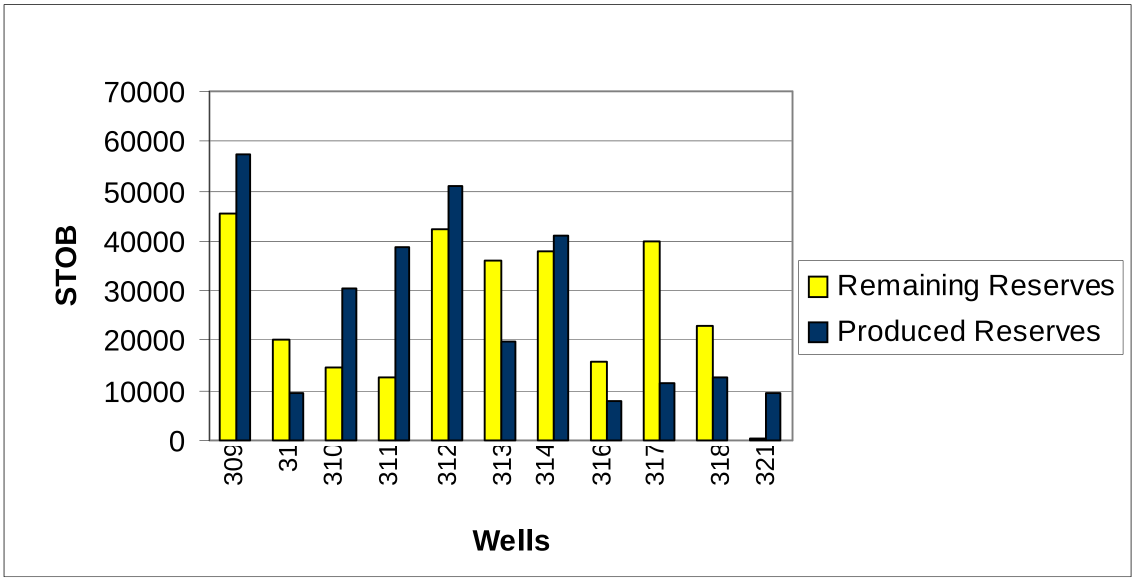

Fig.4. 4 Remaining and Produced Reserves for wells GSU-309,GSU-31,GSU-310,GSU-311,GSU-312,GSU-313,GSU-314,GSU-316,GSU-317,GSU-318, and GSU-321.

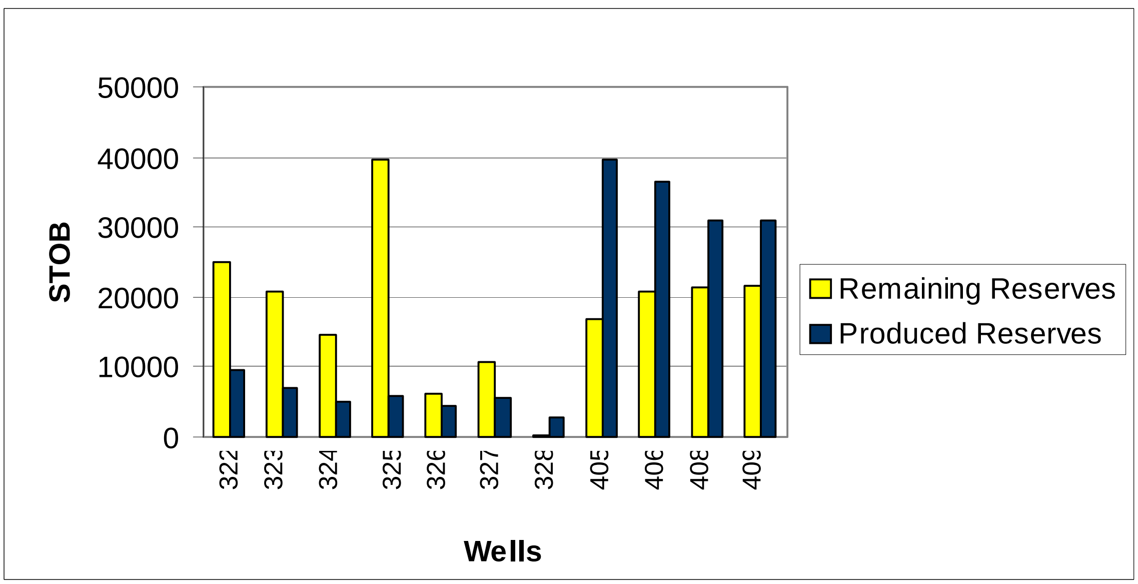

Fig.4. 5- Remaining and Produced Reserves for wells GSU-322, GSU-323, GSU-324, GSU-325, GSU-326, GSU-327, GSU-328, GSU-405, GSU-408, and GSU-409.

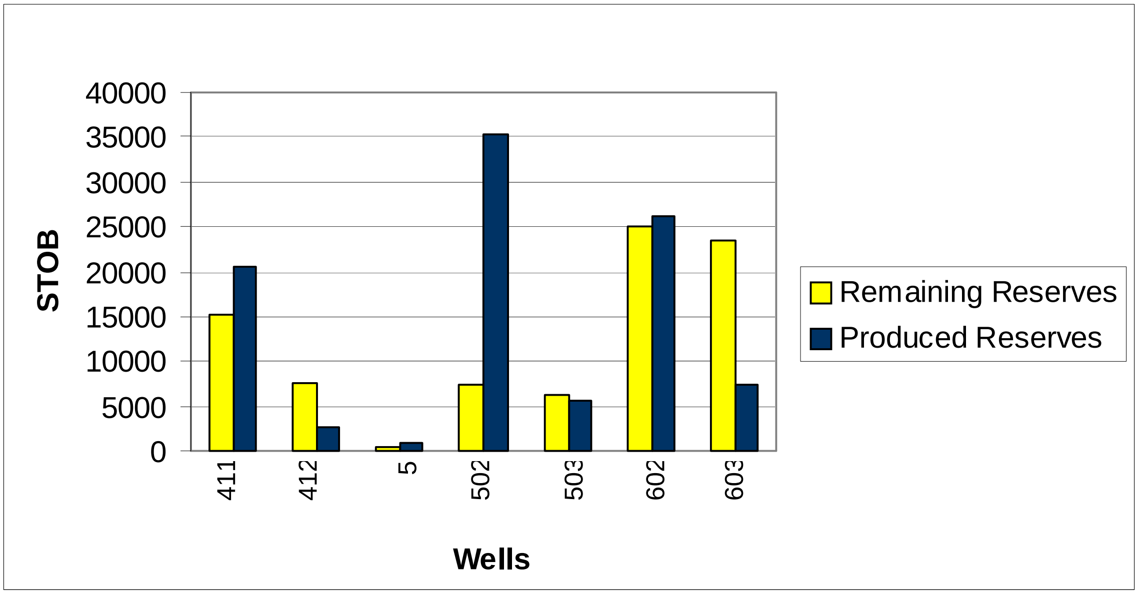

Fig.4. 6- Remaining and Produced Reserves for wells GSU-411,GSU-412,GSU-5,GSU-502,GSU-503,GSU-602, and GSU-602.

We also plotted the results of both remaining reserves and estimated ultimate recovery for every active well in a bubble map. **Fig. 4.7** and **4.8** depict the areal distribution of the remaining reserves and estimated ultimate recovery respectively. In both figures, we can identify prospective areas for the future development of the unit. According to these figures the areas with the most remaining reserves and therefore most opportunities are located in the north-east part of the unit.

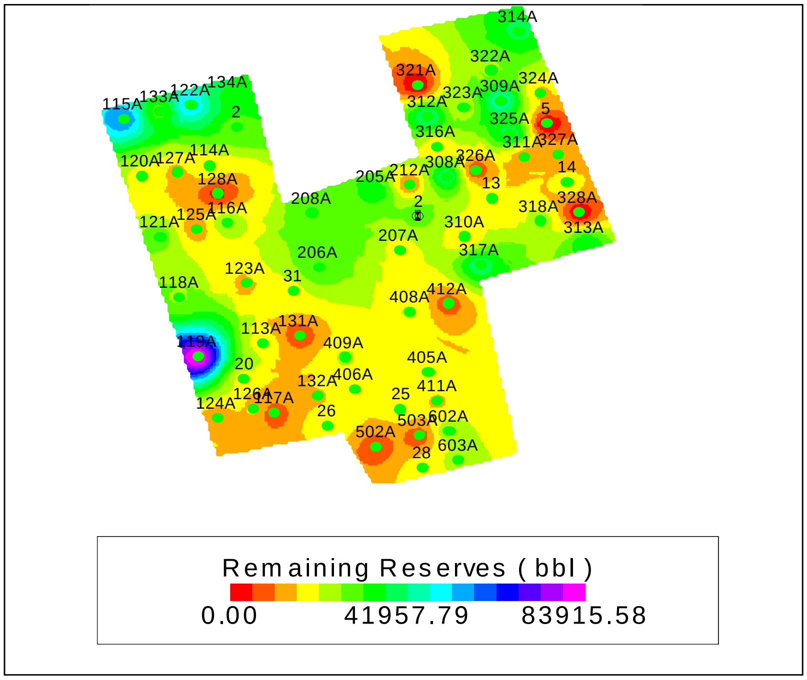

Fig.4. 7- Bubble Maps of Remaining Reserves.

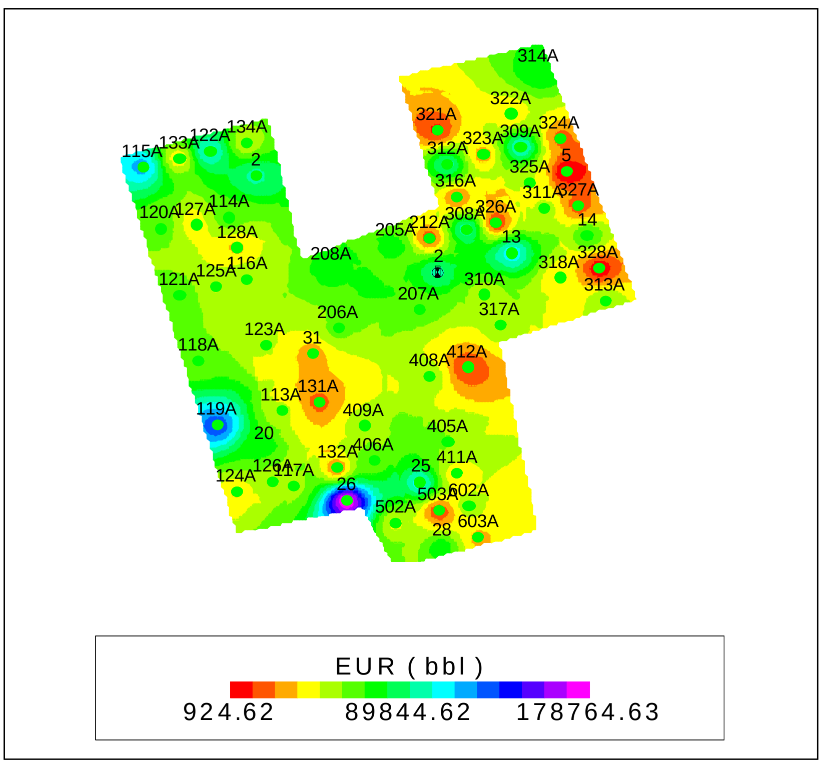

Fig.4. 8 - Bubble Maps of Estimated Ultimate Recovery (EUR).

Besides estimating the remaining reserves using hyperbolic-type decline, we also plotted the water-oil ratio vs. cumulative oil production for the entire unit. **Fig. 4.9** illustrates this analysis**.** The estimated ultimate recovery is equal to the one obtained through the application of hyperbolic-decline type analysis (6.562 million barrels). The extrapolation (dash line is done from the current cumulative production of 2.12 million barrels until reaching economic limit of WOR equal to 50). These results suggest that the unit will be most likely producing and additional 1.410 million barrels through the well currently actives. The figure also illustrates the impact of the different drilling campaigns on the recovery. This analysis also suggests that a new infill drilling campaign (reducing the wells spacing) targeting the areas with the most remaining reserves "sweet spots" showed in **Fig. 4.74** would have a great impact on the production and the recovery.

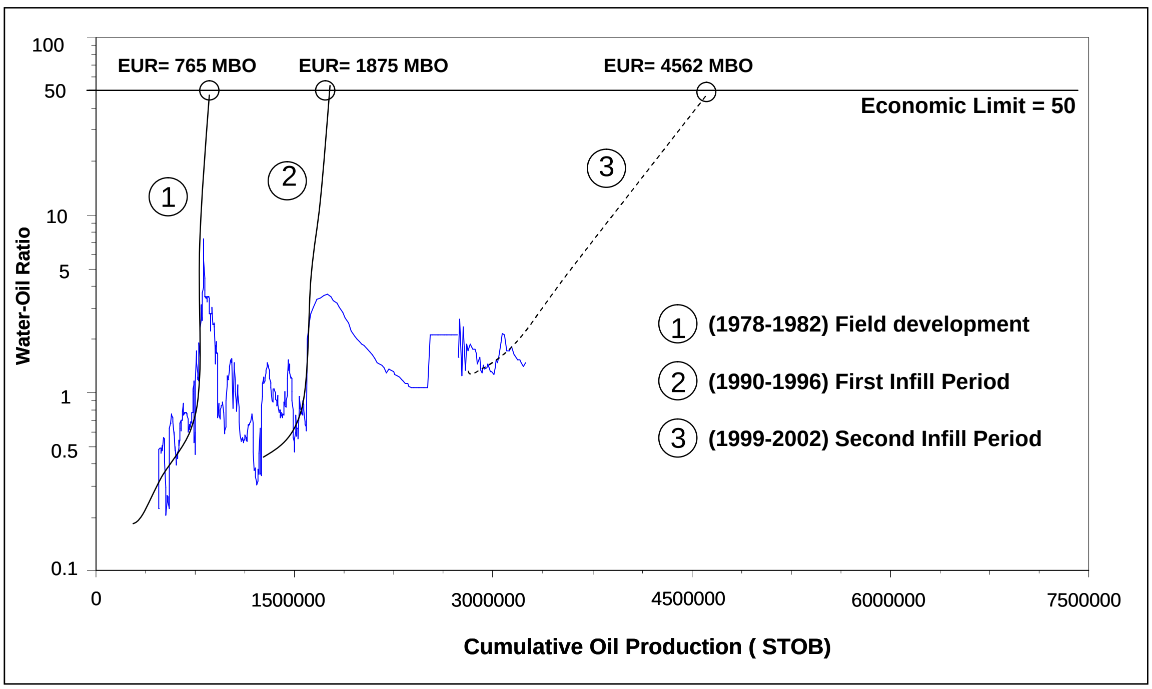

Fig.4. 9- WOR behavior and Cumulative Oil Production due to Infill drilling and Waterflooding in Germania Spraberry Unit.

V. Development Opportunities

There are some opportunities in Germania Spraberry Unit to increase areal efficiency through infill drilling to control reservoir heterogeneity and connectivity. Infill drilling has shown a significant impact on the waterflooding recovery in reservoir which characteristics are similar to those in Germania Spraberry Unit. Based upon an analysis of the performances of 24 reservoirs in West Texas, some studies have shown a certain correlation trend between the waterflood recovery and the well spacing.[3] In the case of Germania Spraberry Unit, more than 80 infill drilling wells have been drilled as the unit have gone from primary on 160 acre spacing , through waterflooding on 80 acre spacing , to 40 acre spacing and oil reserves have been increased from 0.765 to 4.562 million barrels by the implementation of these programs. Based on that, we believe that reducing the well spacing to 20 acres in those areas of greater net thickness and higher percent of sandstone and siltstone along with the new injection pattern; constitute a great opportunity to increase the recovery factor in this unit.

Further use of horizontal drilling (targeting the areas with the most remaining reserves) to take advantage of the natural fractures provides an opportunity to increase well productivity and additional recovery over that of conventional or vertical wells.

Some wells have been completed only in either the unit 1U or in the unit 5U and therefore additional oil recovery could be obtained by well recompletions or by deepening wells currently bottomed in the upper unit (1U). These recompletion opportunities should be evaluated with the purpose of preventing or recovering trapped oil and maximizing sweep efficiency in future operations exposing more of the oil zone, or plugging back to reduce excessive water production. For example, in producing wells that offset, or are adjacent to injectors, some channeling of injected water may occur, resulting in high water cuts. Injection profile work, followed by the use of plugging material may mitigate this problem.

VI. Conclusion and Recommendations

The methodology, analyses, and results described here can be used to improve the recovery and monitor the performance of Germania Spraberry unit, as wells as others waterflood units in Spraberry.

The following specific conclusions can be drawn based on our findings in the research work:

1. Germania Spraberry Unit can be successfully flooded with the new injection pattern and with injection rate of 1600 BWPD.
2. Under the current conditions, 1.414 million barrels can be recovered in the next 20 years through the wells currently active, especially in the north-east part of the unit.
3. Infill-drilling wells reducing the spacing to 20 acres represent an opportunity to increase the recovery factor in the unit.
4. The production performance in Germania Spraberry Unit is clearly dominated by the presence of natural fractures and the wettability of the rock.
5. The average Voidage Replacement observed from 1969 to 1975 indicates that the water injection rate was too high in proportion to the fluid production rate. This may explain the high water cut and rapid breakthrough observed in some wells and is perhaps one of the most responsible factors for the poor performance of unit.
6. The log-log plot of WOR and its derivative provide more insight and information for well performance evaluation and surveillance system. Using this surveillance technique, coning and channeling can be discerned and normal displacement, and breakthrough behavior can be differentiated. Results obtained with this type pf plots, indicate that wells GSU and GSU-5 may be experiencing casing leak.
7. Based on decline-curve analysis for active wells, a bubble map showing the areas with the most opportunities (most remaining reserves) was displayed. The map showed that the areas with the most remaining reserves are located towards the north-east part of the unit.

8. Heterogeneity Indexing is a useful surveillance tool for ranking and identifying specific wells with poor or superior performance in Germania Unit. It can also be used as a quick screening tool to identify opportunities in the area. The results of the application of this screening technique suggest that wells GSU-2, GSU-127, GSU-114, GSU-128, GSU-116, GSU-123, GSU-412, GSU-328, and GSU-5 are good candidates for the application of water control techniques.
9. Tract 2 has the best performance in terms of cumulative oil per acre (938 barrels per acre). This is consequence of the response of the injection in this area (one injector was located at the center of this tract and the rest surrounding the tract.).
10. Wells drilled in the first campaign (from 1957 to 1964) have shown the highest value of average initial rate (48 BOPD) and the performance shown by wells drilled during the third campaign (from 1990 to 1996) demonstrate the importance and impact of infill drilling in this unit.
11. Areas having the best oil-producing wells ("sweet spots") and their adjacent water injection wells formed trends parallel to the main set of natural fractures (N 56^{o} E) and are also correlative with axes of maximum net pay.

Recommendations for future work.

1. Modern well logs and core data are necessary for the purpose of characterization to identify oil-saturated intervals to be completed for oil production and avoid water bearing intervals, evaluate primary cementing in order to prevent casing leaks from recompleted wells, and design an optimum hydrofracturing to minimize the possibility of inducing fractures that might connect oil-prospective intervals with water-bearing intervals.
2. Examine the feasibility of tertiary miscible flooding using CO_2 to reduce the residual oil saturation and increase the recovery in the unit after cessation of the waterflooding project.
3. Examine the feasibility of conducting studies of economic evaluation involving risk and uncertainties in the data and economics conditions.

4. Examine the feasibility of conducting a numerical reservoir simulation in this unit to make sensitivities of different parameters (fracture spacing, matrix and fracture permeability, relative permeability, and capillary effects) and evaluate its effect on the recovery.

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APPENDIX

FORECAST ANALYSIS AND RESERVE ESTIMATION FOR ACTIVE WELLS IN GERMANIA SPRABERRY UNIT.

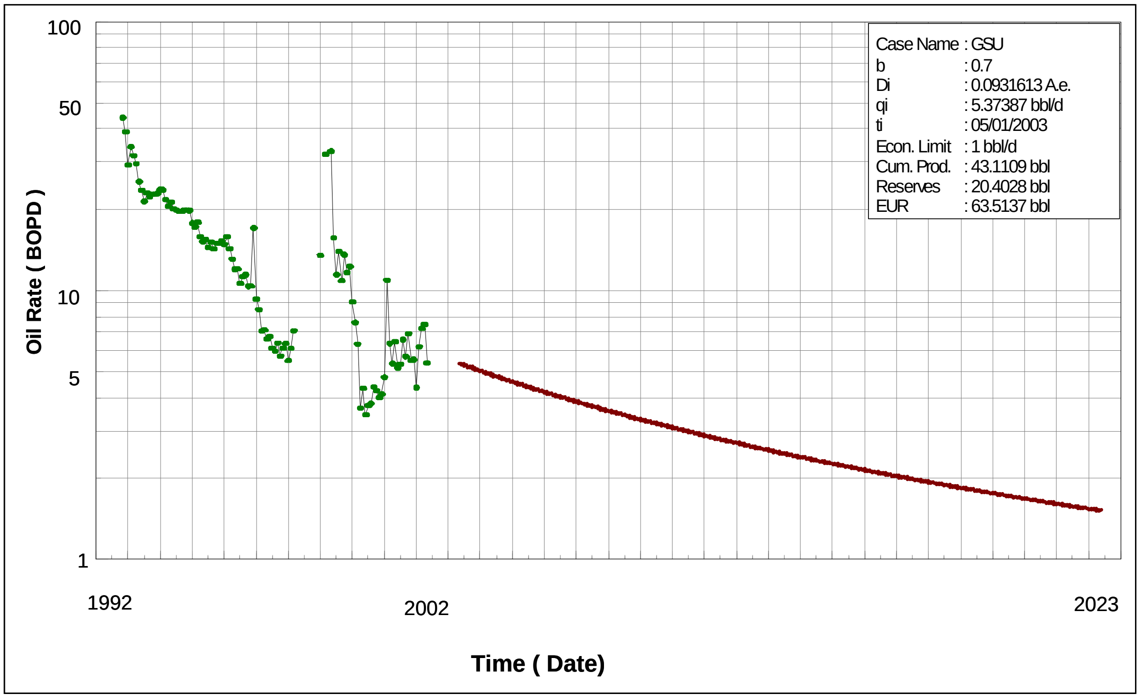


Fig. A. 1- Decline Curve Analysis for Well GSU-114

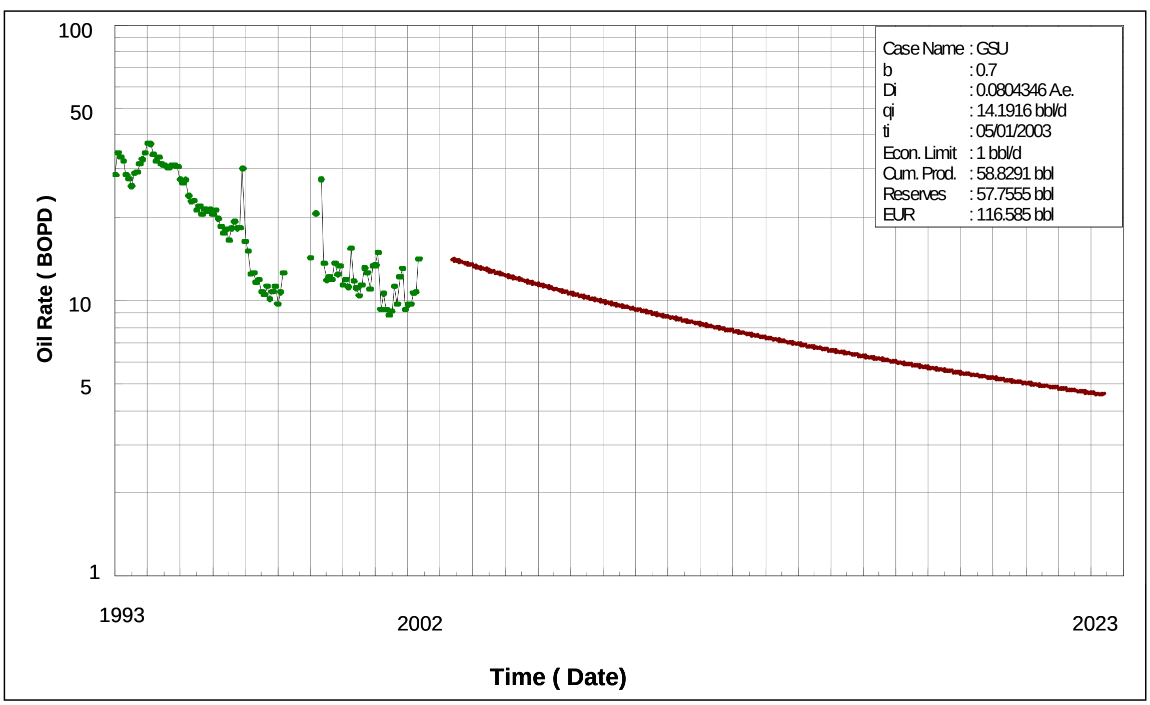


Fig. A. 2-Decline Curve Analysis for Well GSU-115

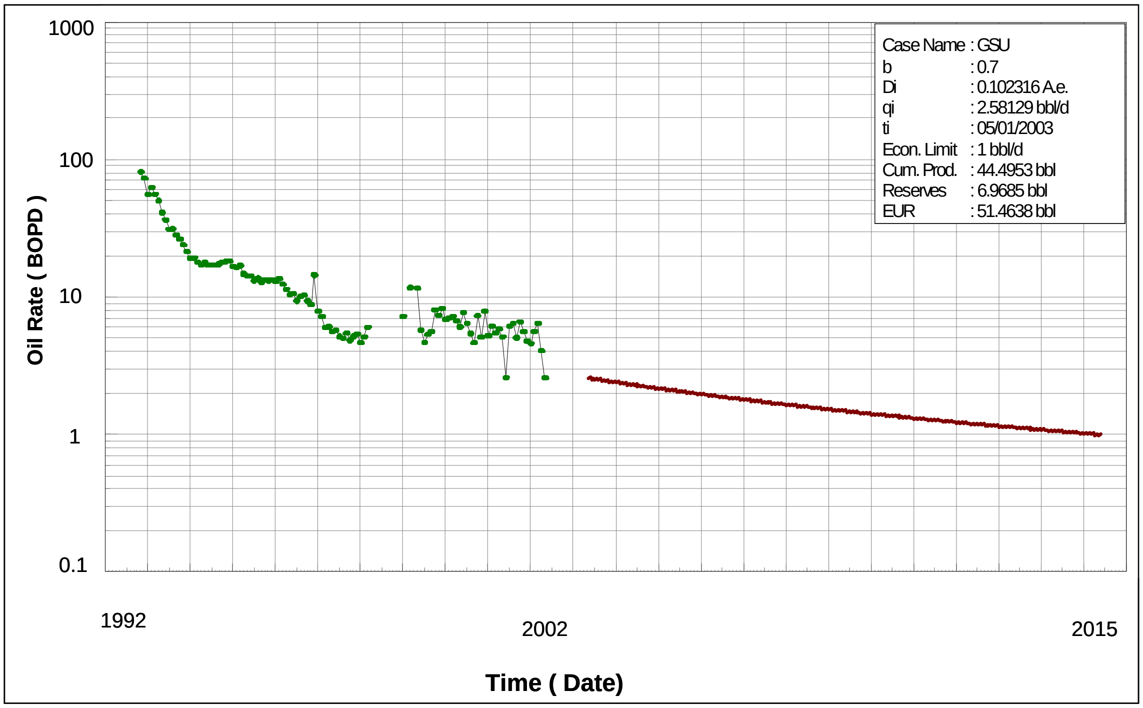


Fig. A. 3- Decline Curve Analysis for Well GSU-117

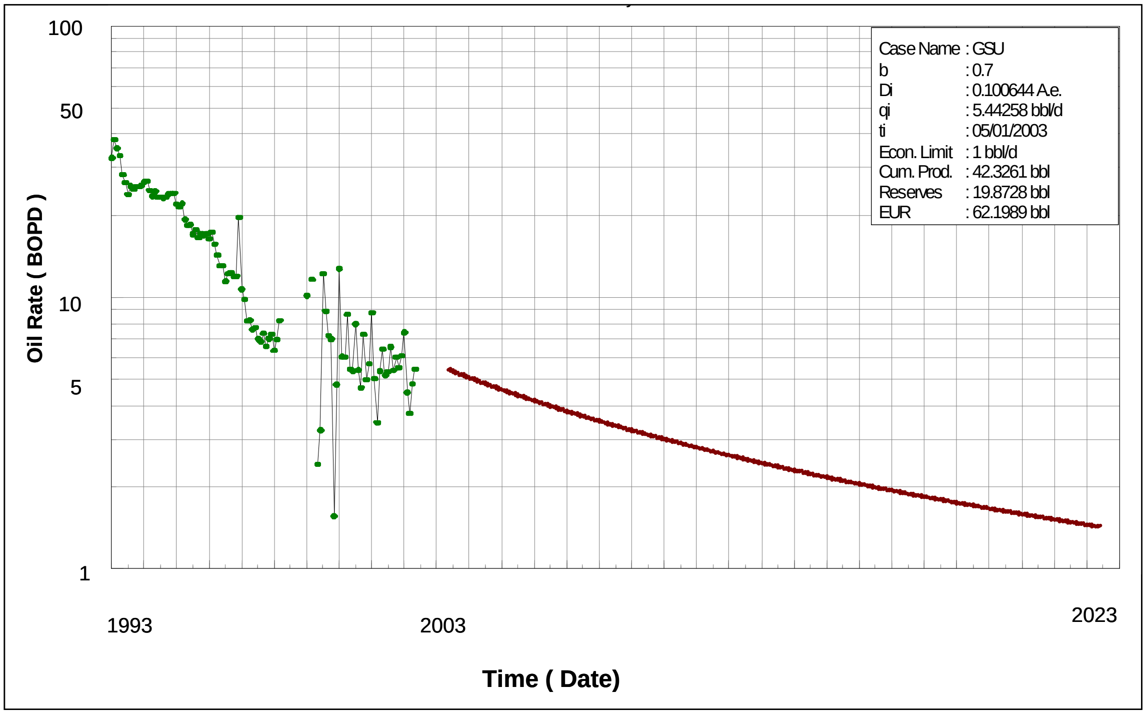


Fig. A. 4- Decline Curve Analysis for Well GSU-120

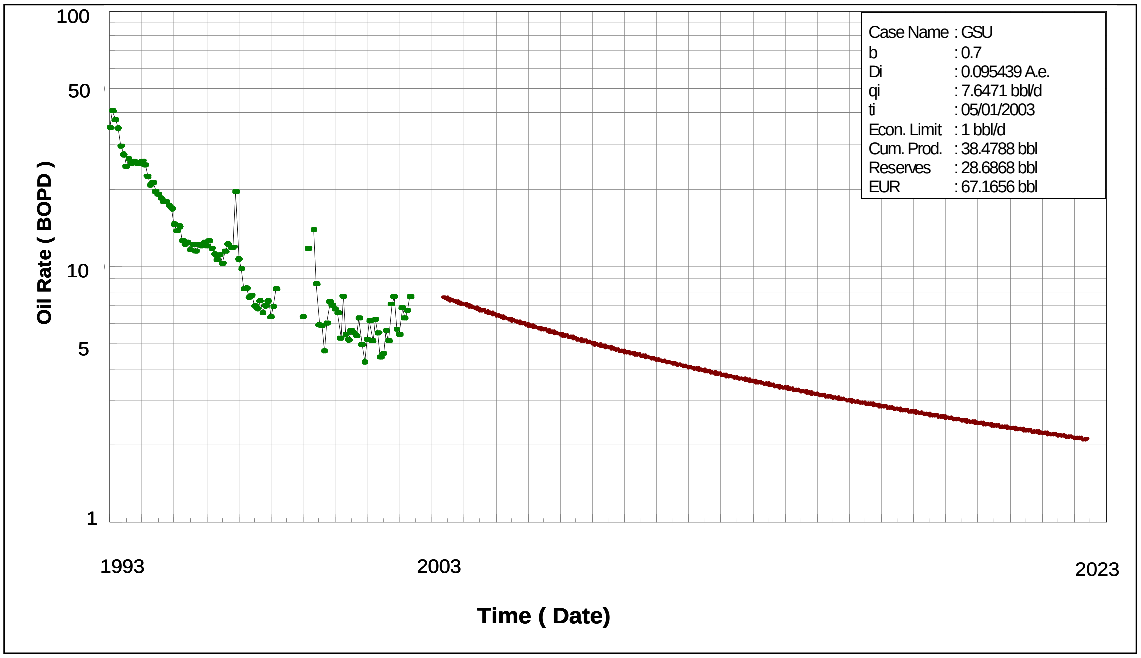


Fig. A. 5- Decline Curve Analysis for Well GSU-121

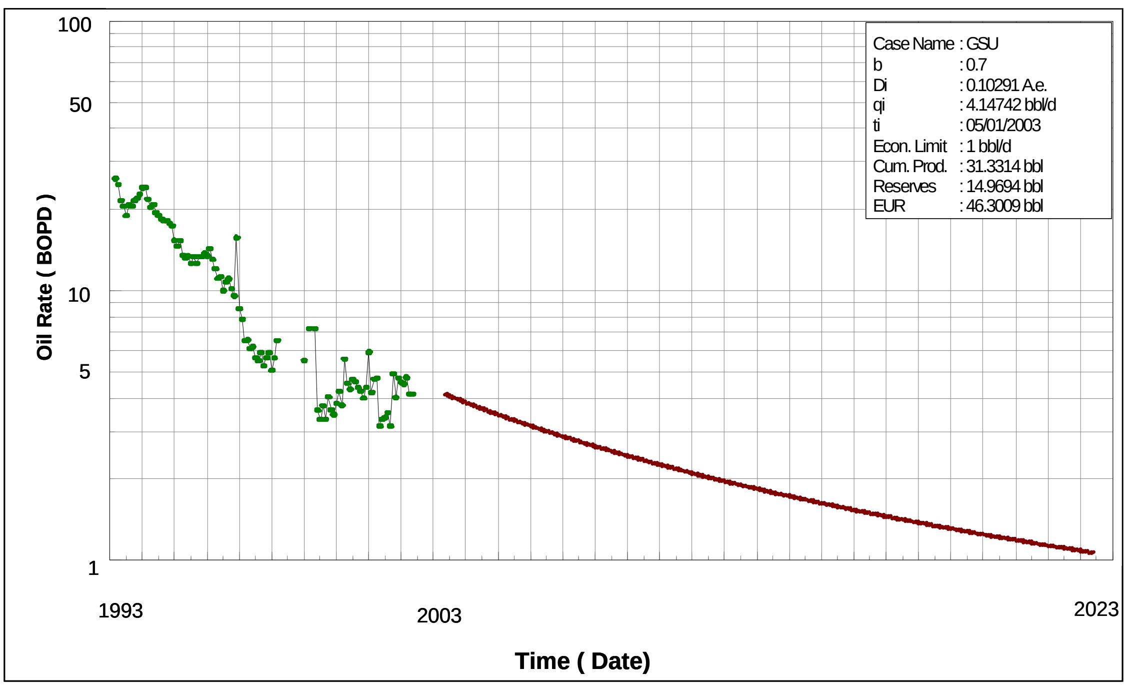


Fig. A. 6- Decline Curve Analysis for Well GSU-123

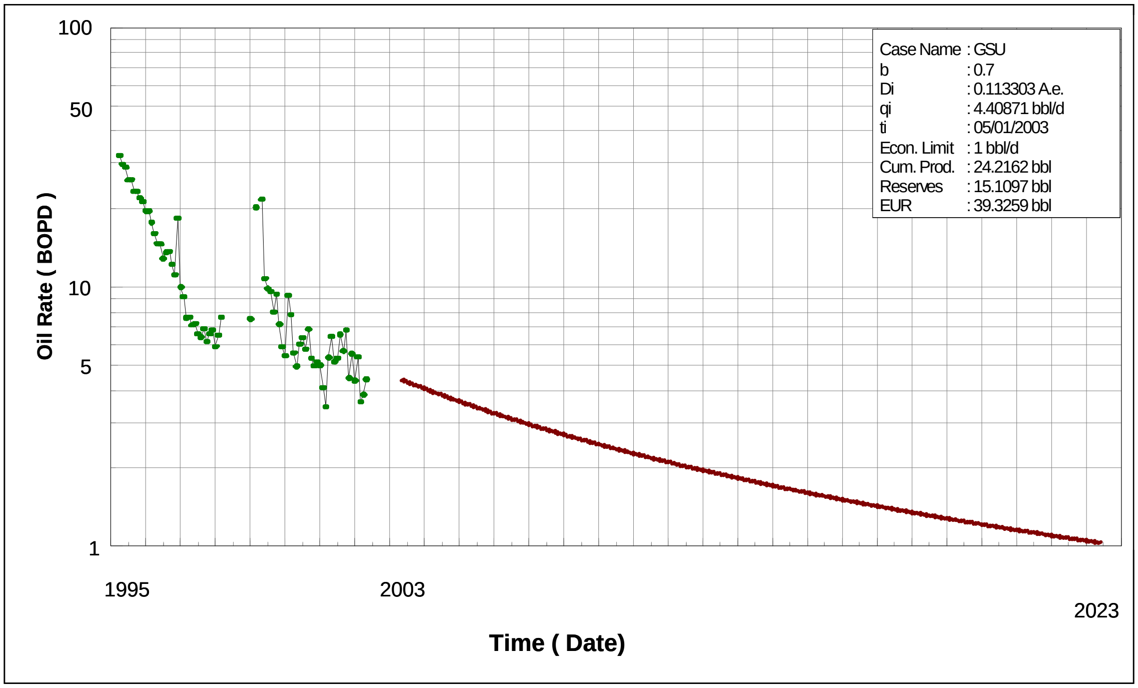


Fig. A. 7- Decline Curve Analysis for Well GSU-127

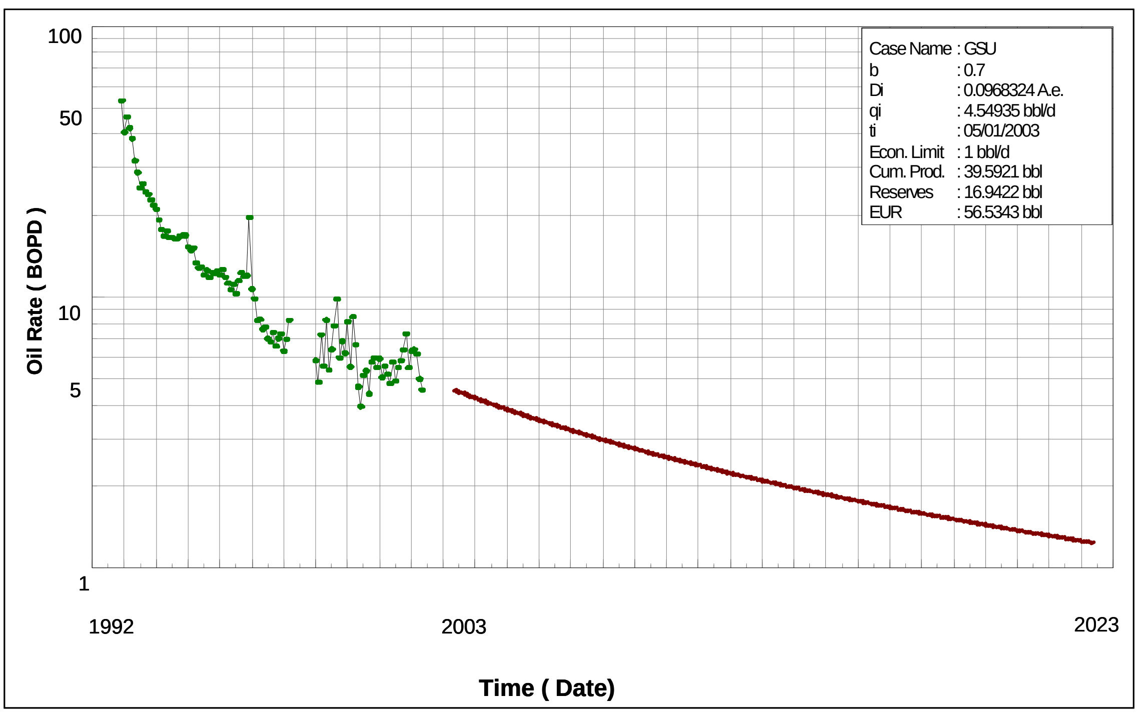


Fig. A. 8- Decline Curve Analysis for Well GSU-405

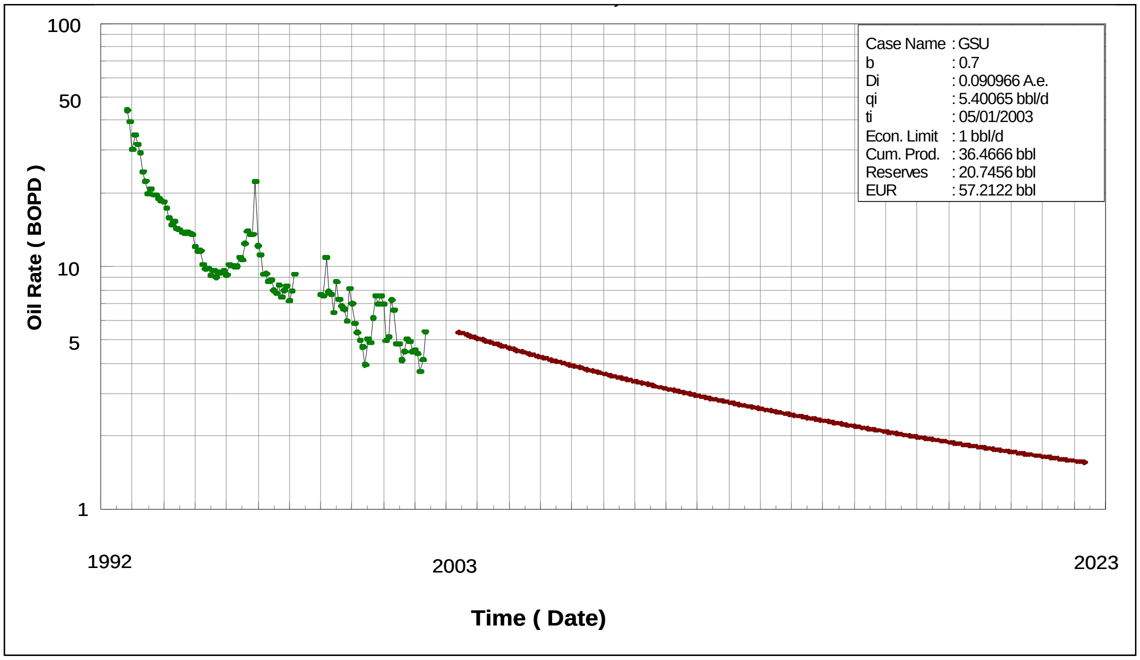


Fig. A. 9- Decline Curve Analysis for Well GSU-406

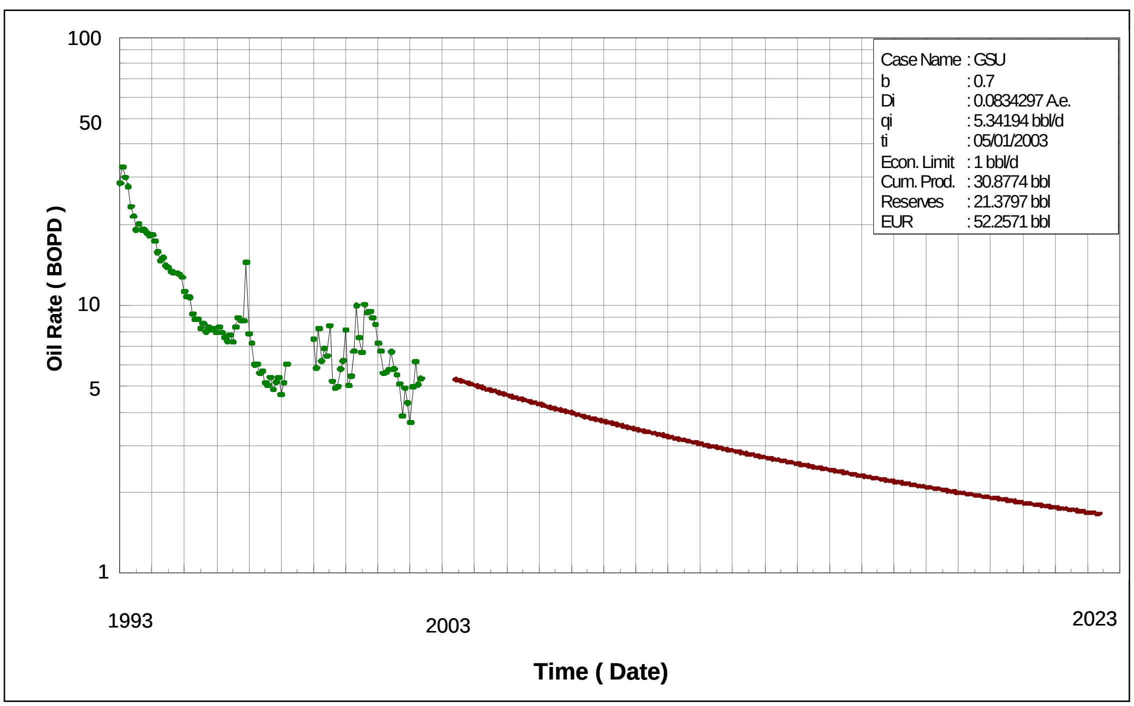


Fig. A. 10- Decline Curve Analysis for Well GSU-408

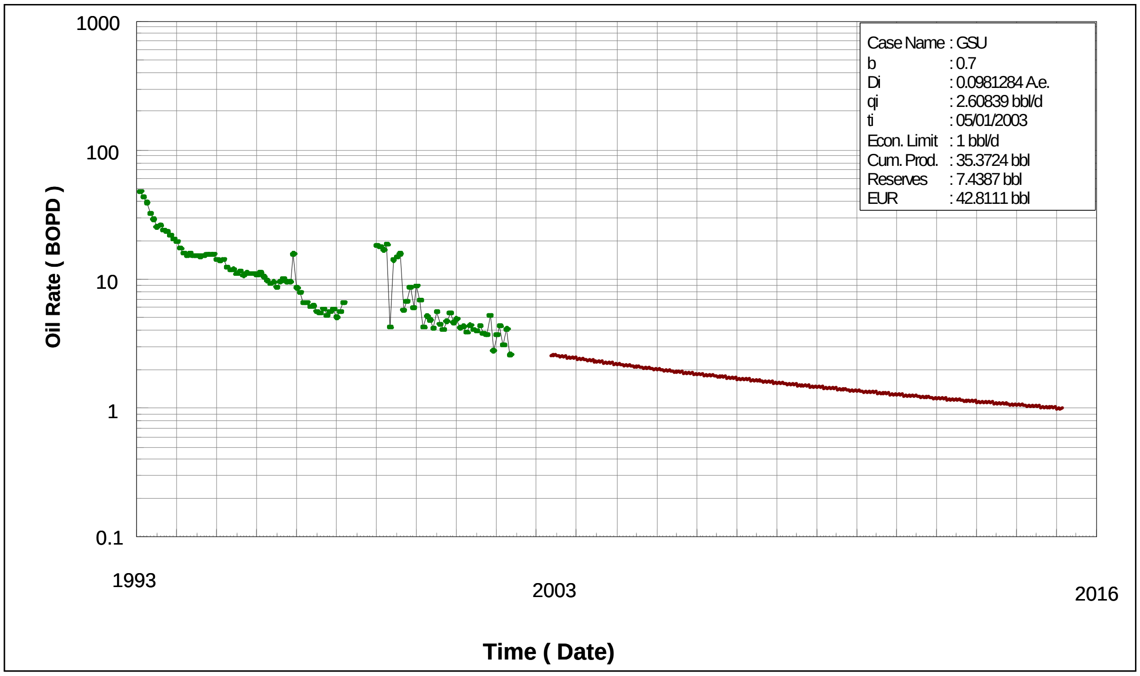


Fig. A.11 - Decline Curve Analysis for Well GSU-502

Table A. 1-Remaining Reserves and Estimated Ultimate recovery for Active Wells.

Well	Remaining Reserves (Barrels)	Cumulative Oil (Barrels) (As of 2003)	Estimated Ultimate Recovery (Barrels)
113A	19216	27587	46802
114A	20403	43111	63514
115A	57755	58829	116585
116A	25131	31429	56560
117A	6969	44495	51464
118A	25742	34287	60030
119A	83916	46613	130529
120A	19873	42326	62199
121A	28687	38479	67166
122A	53172	51211	104383
123A	14969	31331	46301
124A	11488	21868	33356
125A	12909	31863	44772
126A	16149	33368	49517
127A	15110	24216	39326
128A	3169	28542	31711
13	18372	89433	107805
131A	6599	12883	19483
132A	15084	8180	23263
133A	28799	6655	35454
134A	36255	8286	44541
14	19352	51288	70640
2	28723	64118	92841
20	18643	52566	71209
205A	34693	36747	71440
206A	31784	28078	59862
207A	19231	38885	58116
208A	29909	41669	71578
212A	9699	5481	15180
25	19582	86032	105614

Table A.1-Continued.

Well	Remaining Reserves (Barrels)	Cumulative Oil (Barrels) (As of 2003)	Estimated Ultimate Recovery (Barrels)
26	19608	159157	178765
28	18780	57354	76134
308A	41480	55329	96809
309A	45525	57294	102820
31	20027	9602	29629
310A	14684	30337	45021
311A	12508	38629	51137
312A	42395	51011	93406
313A	35863	19642	55505
314A	37824	41292	79116
316A	15661	7880	23541
317A	39891	11367	51259
318A	23002	12622	35623
321A	400	9514	9914
322A	25111	9602	34713
323A	20902	6938	27841
324A	14648	5125	19774
325A	39668	5829	45497
326A	6061	4460	10521
327A	10660	5712	16372
328A	400	2933	3333
405A	16942	39592	56534
406A	20746	36467	57212
408A	21380	30877	52257
409A	21550	30963	52513
411A	15306	20575	35881
412A	7595	2715	10310
5	400	925	1325
502A	7439	35372	42811
503A	6337	5668	12005
602A	24970	26139	51109
603A	23391	7391	30782

II. GERMANIA SPRABERRY FIELD DEMONSTRATION STATUS

1. Introduction

This report is a continuation of our previous report on waterflooding performance in Germania pilot. Our previous reports[1-4] can be summarized as follows:

1. The new location of injectors had been proposed.
2. The wells that had casing leaks were identified.
3. The amount of water injection required was maintained based on Voidage Replacement Ratio (VRR).
4. The responses of water injection were observed at each observation well on daily basis.

In this period, we continue to observe the response of water injection at each production wells and group of the wells in each track. The new pilot consists of six injectors, three wells converted to water injection (17, 407A and 410A,) two wells returned to water injection (11W and 22W) and a new injection well (214W) as shown in Fig. 1. The water injection began on Feb 3, 2003 with a constant rate of 270 BWPD/well (Fig. 2). The total amount of water that had been injected up to April 4, 2004 was about 685, 000 BBLs (Fig. 3). The Voidage Replacement Ratio (VRR) is expected to be one to balance the amount of water being injected and the amount of fluid being produced. Two different injection periods were compared to analyze the effect of VRR. The first injection period was from 1965 to 1989 (Fig. 4) and second injection period was from January 2003 to the current time (04/4/2004). The first period exhibited an overall VRR greater than one suggesting that the volume being injected exceed the total volume being produced. From 1969 to 1975 the average value of VRR was 20, indicating that 20 barrels of water were injected per 1 barrel of fluid produced (oil, water, and gas). This may explain that the high water cut and rapid breakthrough observed in some wells (especially those surrounding the injectors) and is perhaps one of the most responsible factors for the poor performance of the unit during this period. The second period exhibits an overall VRR of one (Fig. 5), thus indicating that the energy balance was maintained though out this pilot. However, after drilled nine new wells the VRR dropped below one, indicating less of total amount of water injection. Due to low injection, after sometimes, the fluid produced also decreased that causes VRR was approaching back to one again. We then analyzed the effect of water injection on production wells. We categorize the wells in each tract into three group based on water production performance as follows (Table 1):

1. Wells that were affected by water injection
2. Wells that show a decrease in water production during water injection
3. Wells that were not obviously affected by water injection

From analyzing the water production in each well, only six current active wells were affected by water injection (Fig. 6). Four of these wells (113A, 123A, 131A and 132A) are located in Tract 1 and two of them (206A and 207A) are in Tract 2. All these active production wells are located in on-trend direction. However, there are no an increase in oil production as expected. Three wells in this tract (406A, 408A and 409A) that produced high water rate had been shut-in to reduce water production and allow water to spread further.

Surprising, till to date none of the wells in Tract 3 were affected by water injection. Somehow, the water still has not reached Tract 3 location. It may be in the filling up process. We may see the waterflood response after this process is over.

The effect of water injection has also still not reached all wells in the Tract 1 including the new wells (Fig. 7). Two new wells (213A and 413A) in Tracts 2 and 4, which are located in off-trend wells and near injection wells, are not affected by waterflooding (Fig.1). Even, water production rates decrease significantly with time indicating no response of water injection to these wells. Both wells produced at high initial oil production and later on declined rapidly. Well #213A produced at initial rate of 229 bopd (Fig. 8.) Current production (3/31/04) drops to 47.1 bopd. Well #413A produced at initial rate of 87 bopd. Current production (4/03/04) drops to 10.1 bopd (Fig. 8). All the new wells in Tract 3 show similar water production response as those in Tract 2 (Fig. 9). Even though the oil production decreased with time but the oil production trend were different and oil rate decline were not as dramatic as those in Tract 2 were. Well #330A was completed in 11/20/03 with initial rate of 35.2 bopd and the production increased to 69.2 bopd on 12/19/03. The current production rate (03/30/04) decreased to 24.2 bopd. Well #330A was completed in 10/25/03 with initial rate of 6 bopd and the production increased to 61 bopd on 10/25/03. The current production rate (03/30/04) decreased to 24.2 bopd. Well #331A was completed on 10/5/03 with initial rate of 47.5 bopd and the production increased to 87 bopd on 10/16/03. The current production rate (3/29/04) decreased to 23.3 bopd.

Individual wells were observed, as well as the group of the wells in each track. We observed the water injection response in the track 2, 3 and 4 daily bases. Figs. 10-12 show the production performance in each tract. Most of the sudden increases in oil production are due to the new production wells not the response of water injection.

2. Summary

1. The current amount of water injection rate is not enough to support the current production rates based on response of new production wells and VRR analysis.
2. The effect of water injection still does not reach many wells in Tracts 1 and 3. There may be the water is still in the filling up process. We may need to wait a longer time to see the waterflood response. The current response can be summarized as follows:
    - Waterflooding process has affected only six wells located in the on-trend direction and near the injectors as indicated by an increase in water production.
    - Wells located in off-trend location and even near injection wells has still not been affected by water injection.
    - The response of new production wells shows that the water production decreases even during water injection indicating that the performance of these wells are not supported by on-going water injection.

3. References

1. Schechter *et al*.: "Preferred Waterflood Management Practices for the Spraberry Trend Area," Semi-Annual Report (DOE Contract No.: DE-FC26-01BC15274), Oct. 2001 – March 2002.
2. Schechter *et al*.: "Preferred Waterflood Management Practices for the Spraberry Trend Area," Semi-Annual Report (DOE Contract No.: DE-FC26-01BC15274), April 2002 – Sept. 2002.

3. Schechter *et al*.: "Preferred Waterflood Management Practices for the Spraberry Trend Area," Semi-Annual Report (DOE Contract No.: DE-FC26-01BC15274), Oct 2002 – March 2003.
4. Schechter *et al*.: "Preferred Waterflood Management Practices for the Spraberry Trend Area," Semi-Annual Report (DOE Contract No.: DE-FC26-01BC15274), April 2003 – Sept. 2003.

Table 1 – Water production performance in each tract

Water Production Performance	Tract 1	Tract 2 and 4	Tract 3
Wells that were affected by water injection	113A, 123A, 131A, 132A	206A, 207A, 406A**, 408A**, 409A**	
Wells that show a decrease in water production during water injection	114A, 115A, 121A, 125A, 128A, 136A*, 141A*	213A*, 413A*	330A*, 331A*, 332A*
Wells that were not obviously affected by water injection	116A, 117A, 118A, 119A, 120A, 122A, 126A, 127A, 127A, 13, 130A, 133A, 134A, 14	205A, 208A, 212A, 405A, 411A, 412A	308A, 309A, 310A, 311A, 312A, 313A, 314A, 316A, 317A, 318A, 321A, 322A, 323A, 324A, 325A, 326A, 327A, 328A

*) New wells drilled in 2003
**) Wells were closed due to high water production

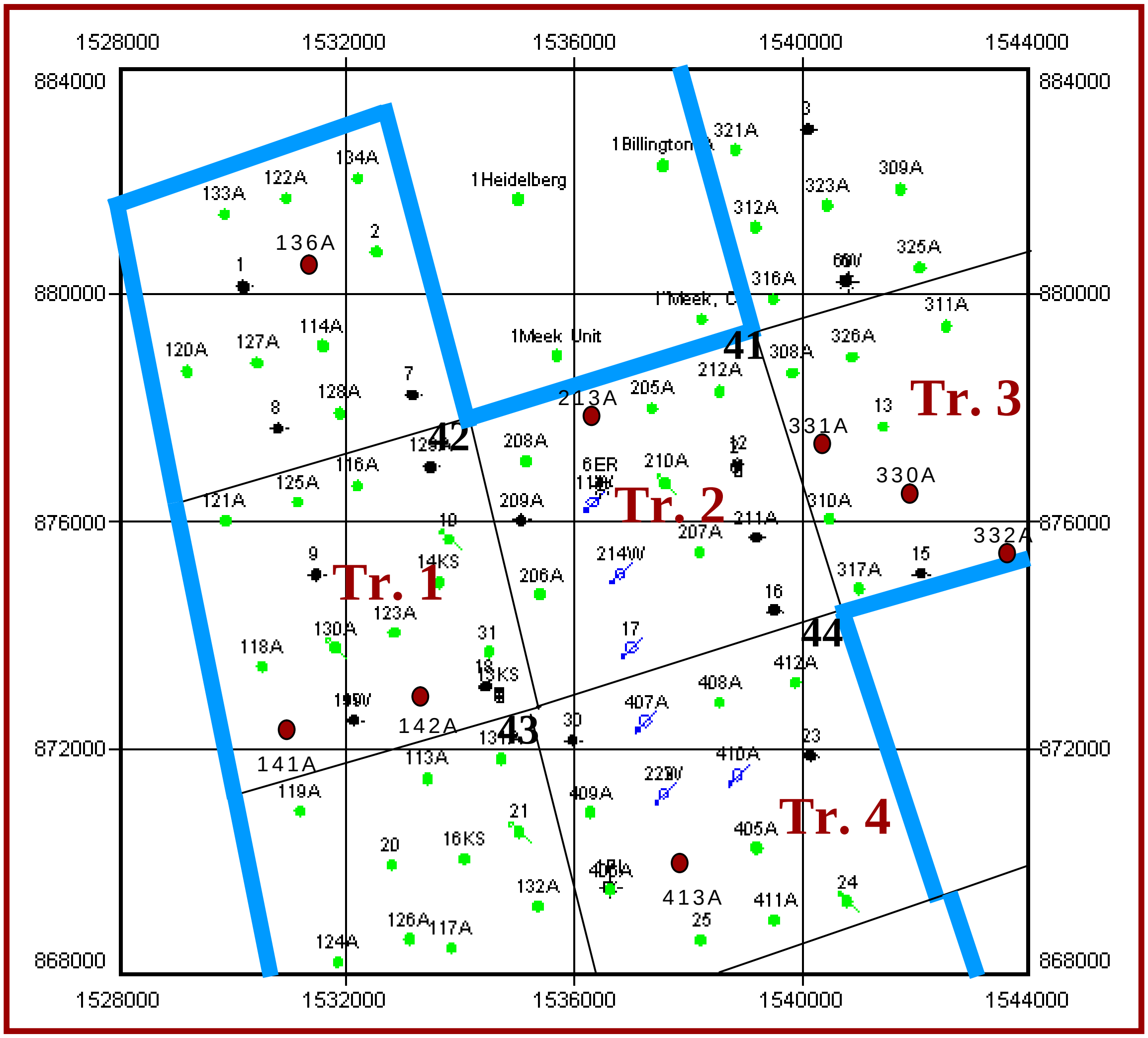


Fig. 1 – Location of new wells drilled in 2003 (red dot symbol)

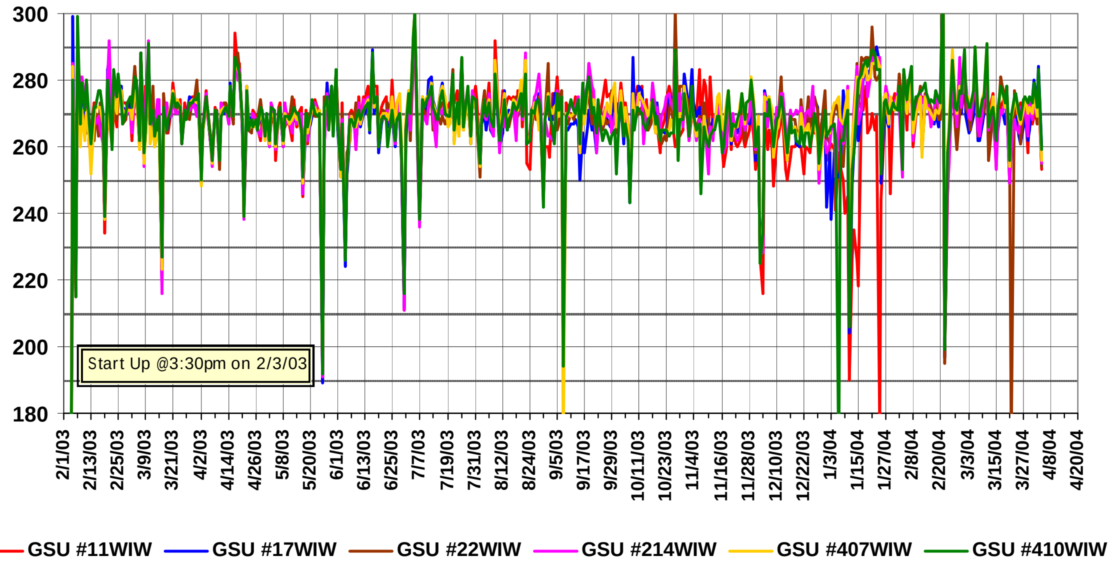


Fig. 2 – Water injection rate from six injectors

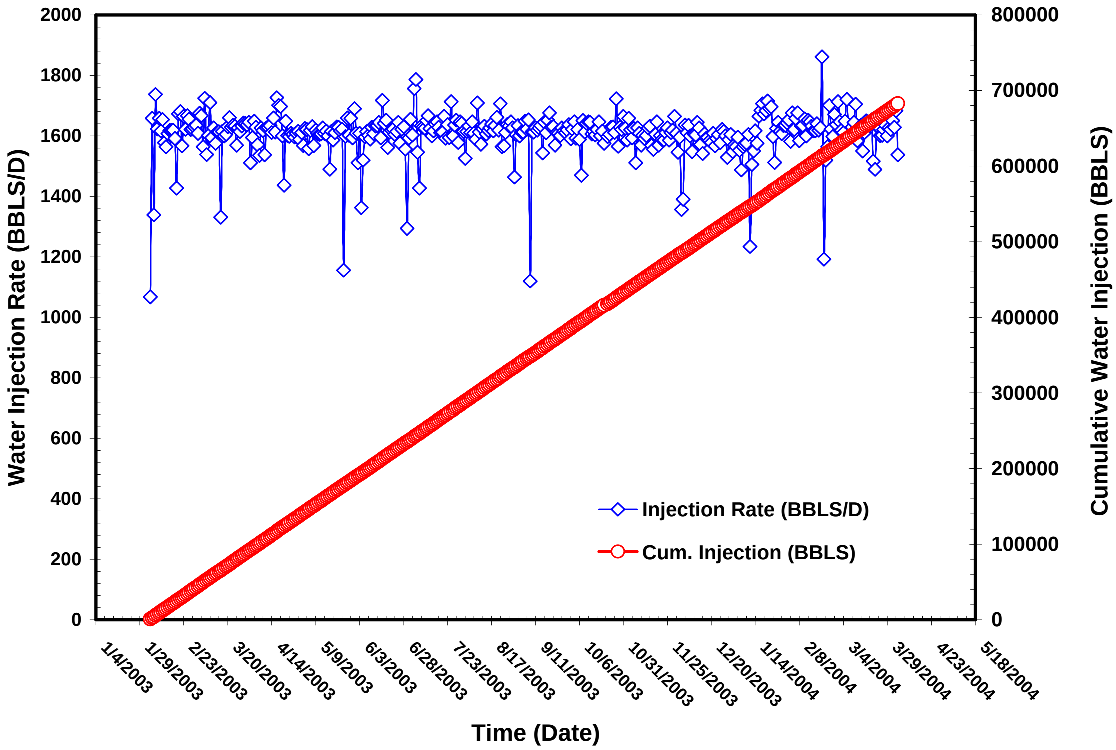


Fig. 3 – Total water injection rate from six injectors

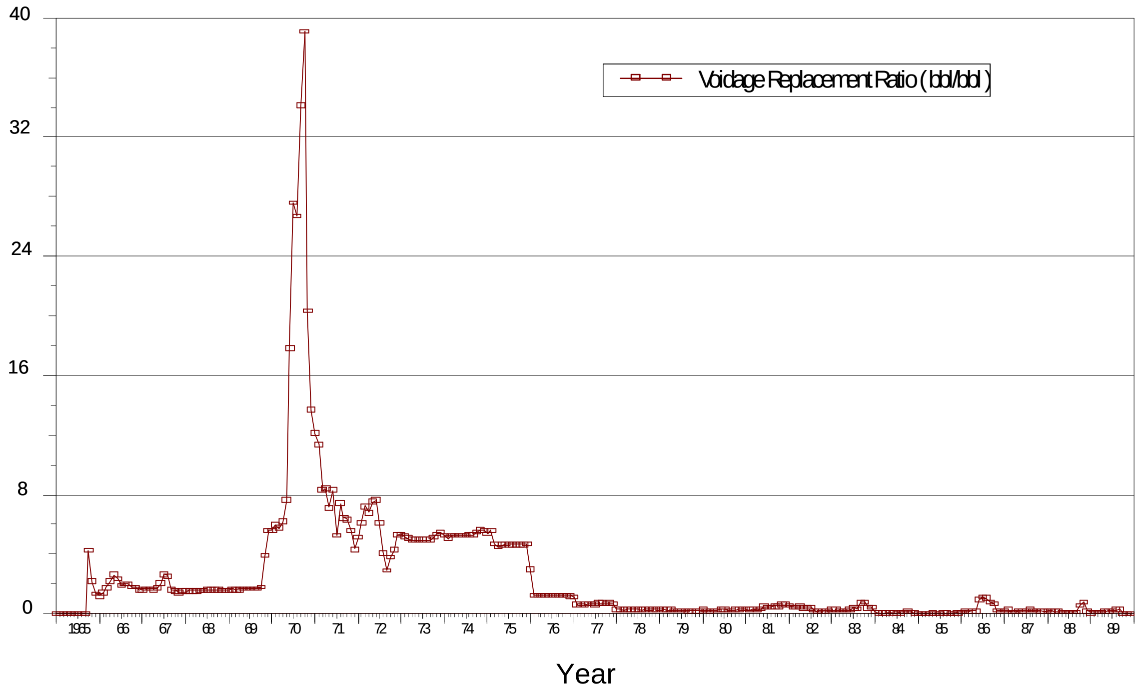


Fig. 4 – Voidage Replacement Ratio (1965-1989)

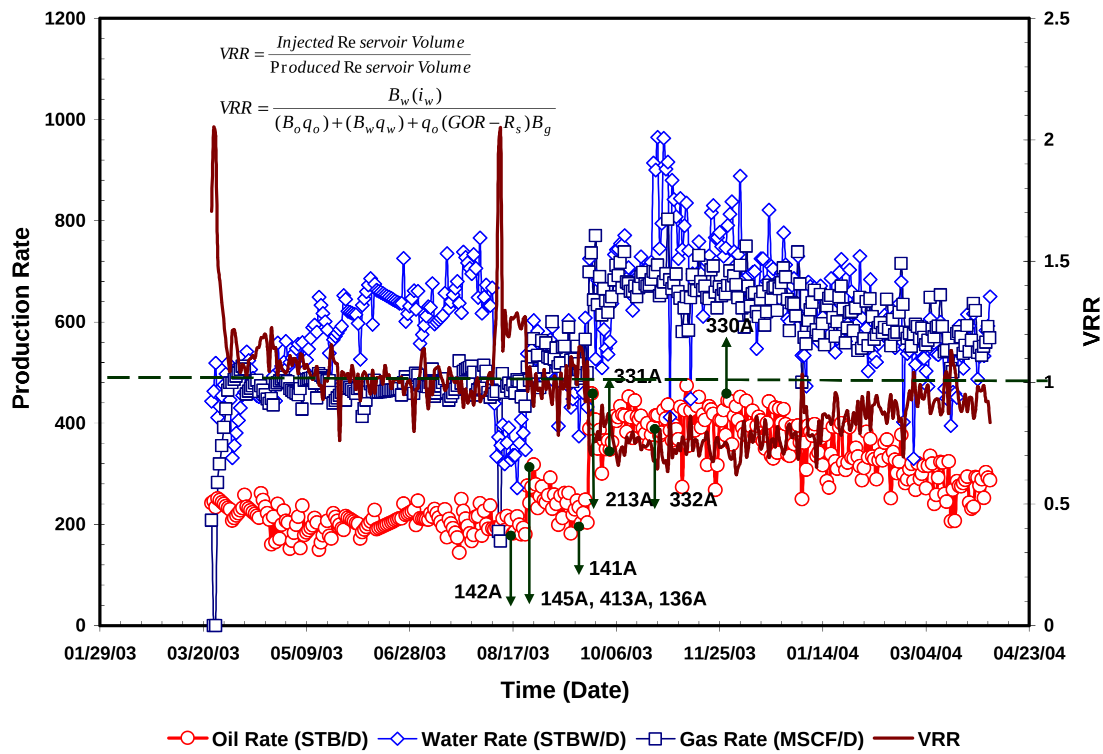


Fig. 5 – Current Voidage Replacement Ratio

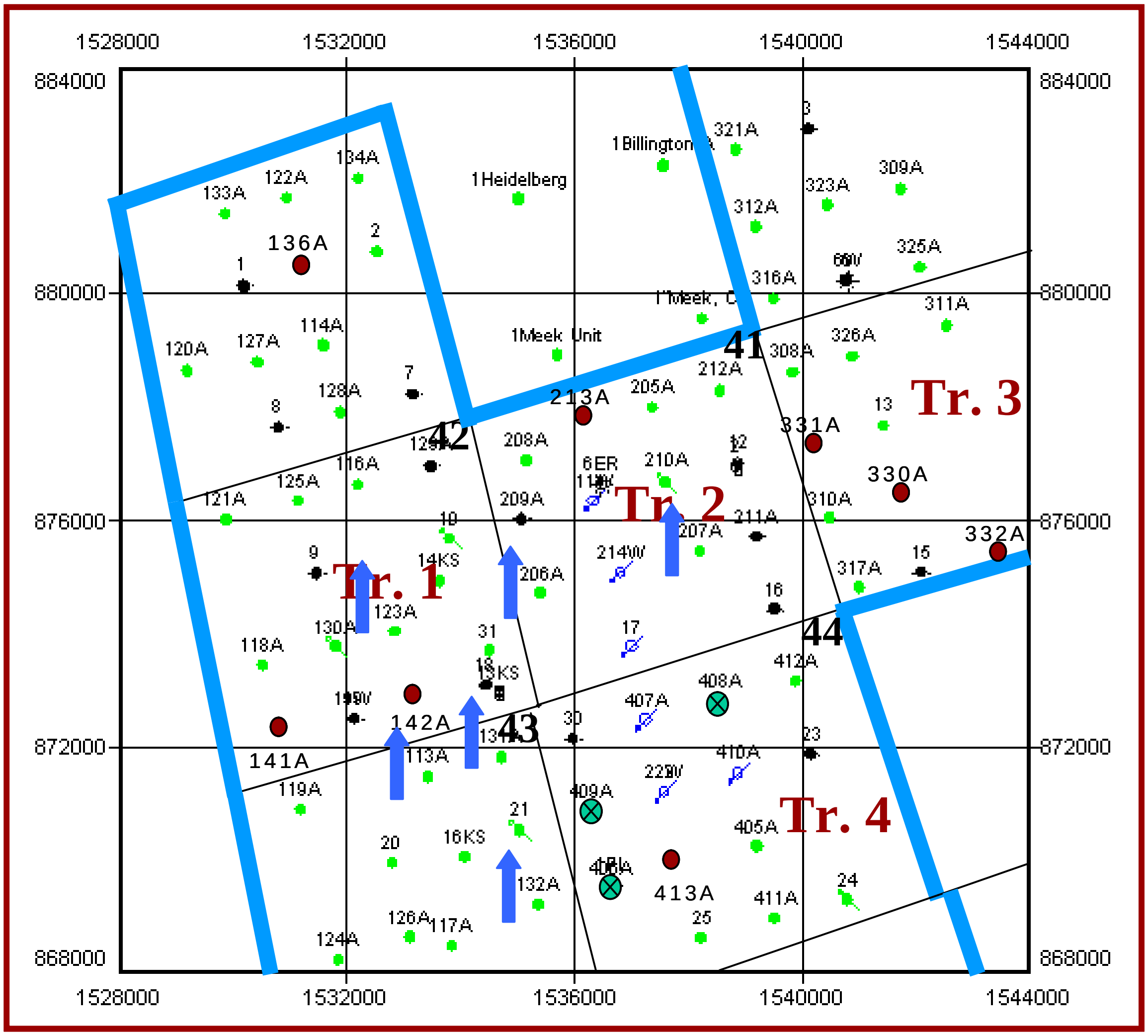


Fig. 6 – Wells experience increase in water production

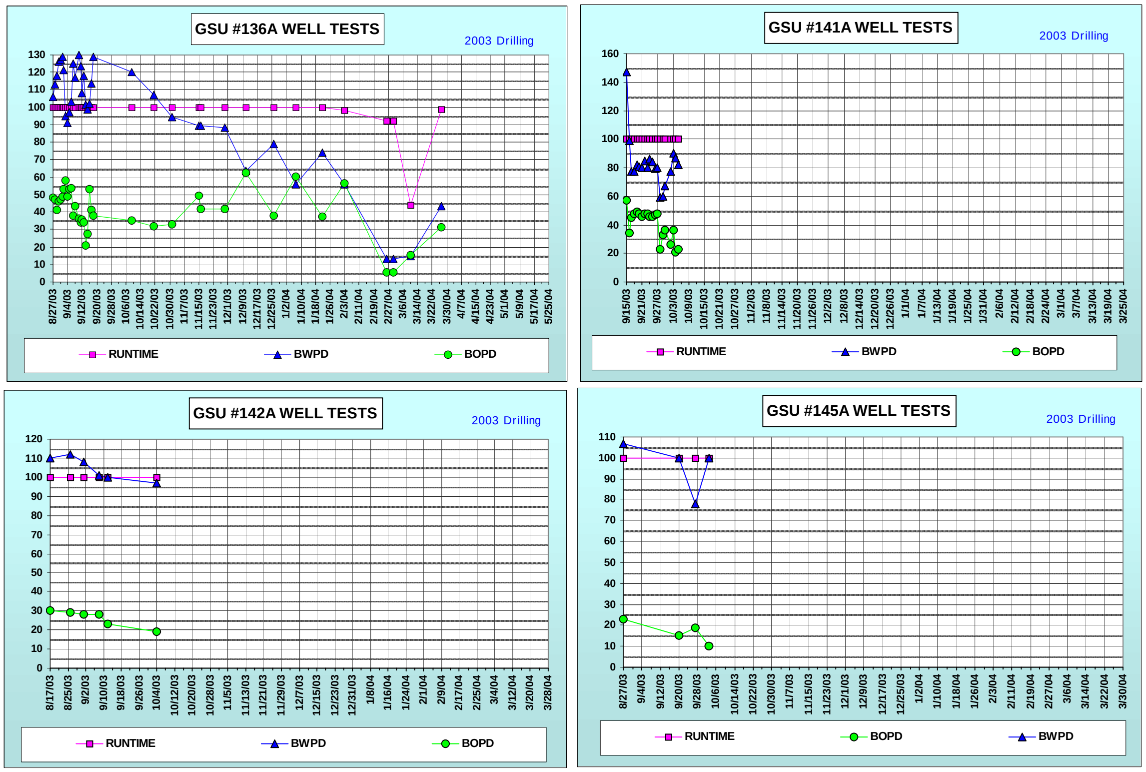


Fig. 7 – Performance of new wells in Tract 1

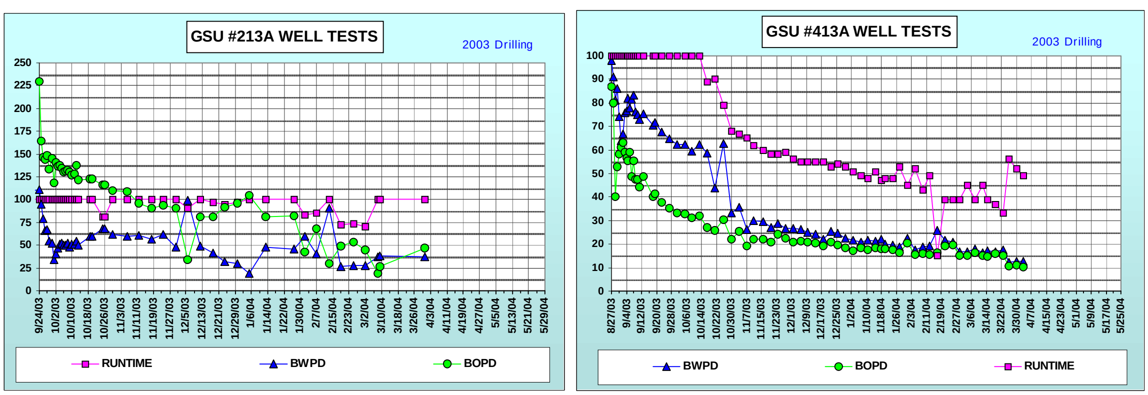


Fig. 8 – Performance of new wells in Tracts 2 and 4

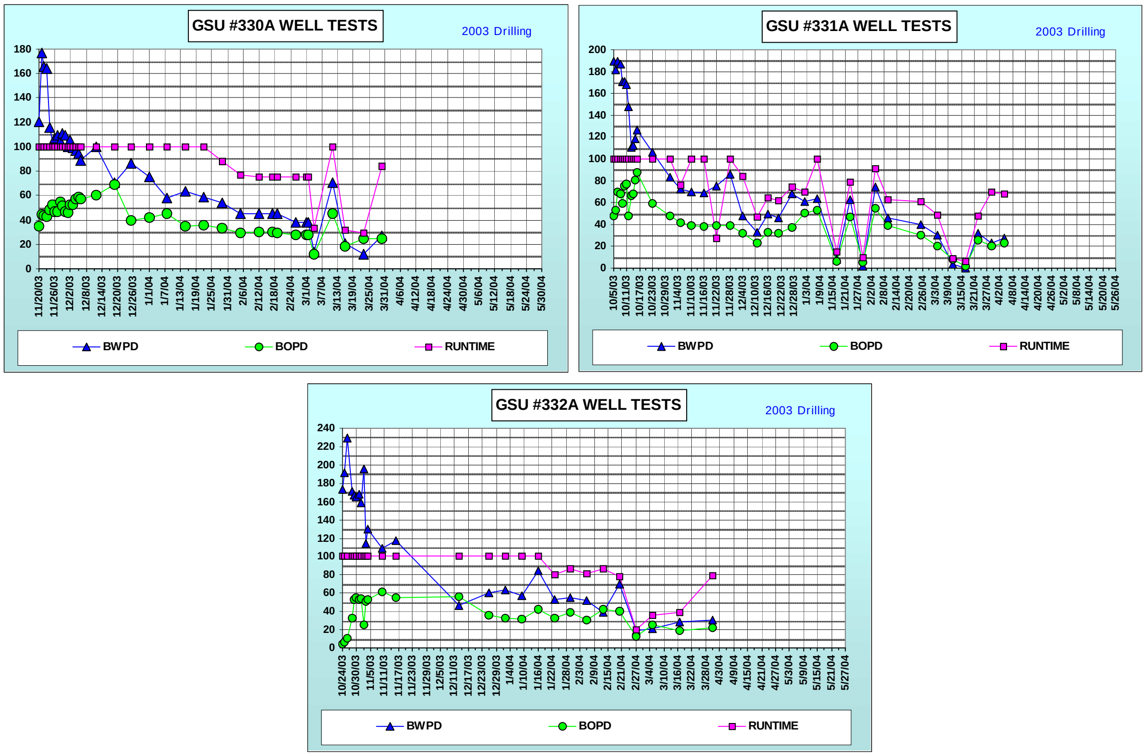


Fig. 9 – Performance of new wells in Tract 3

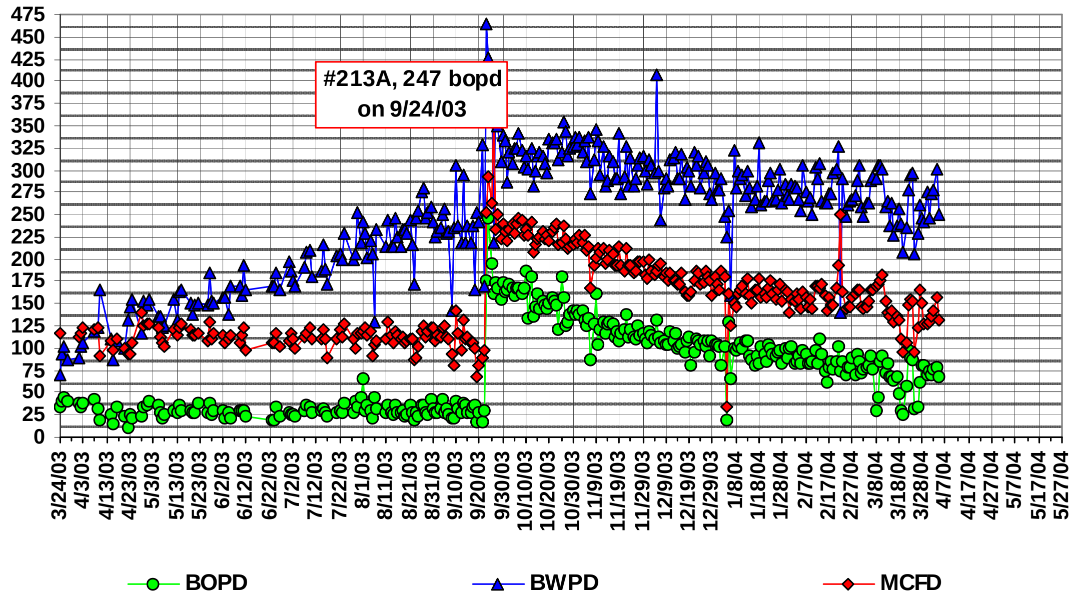


Fig. 10 – Production performance in Tract 2

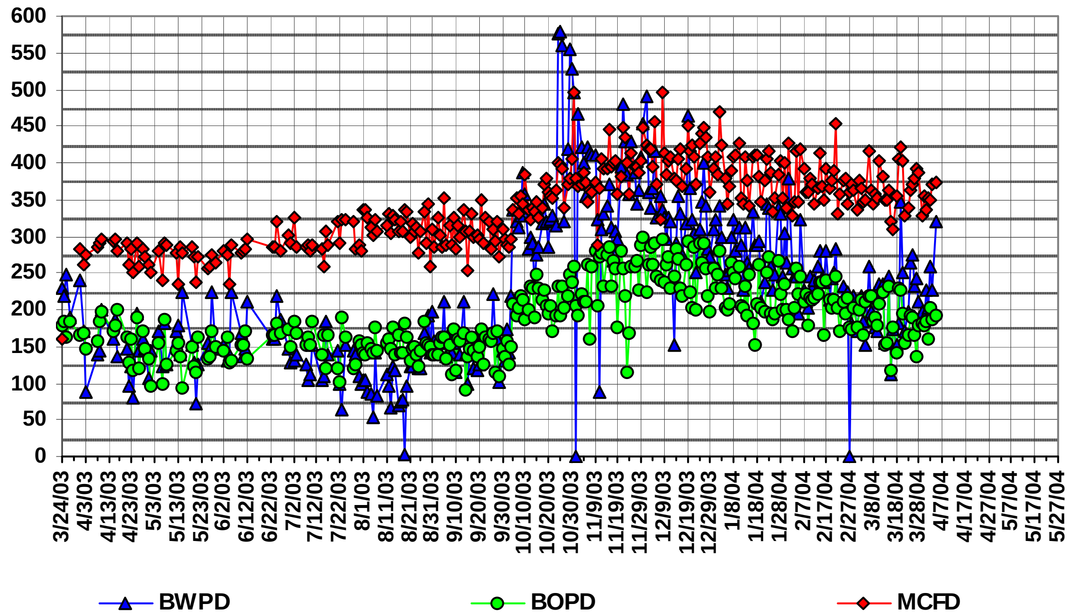


Fig. 11 – Production performance in Tract 3

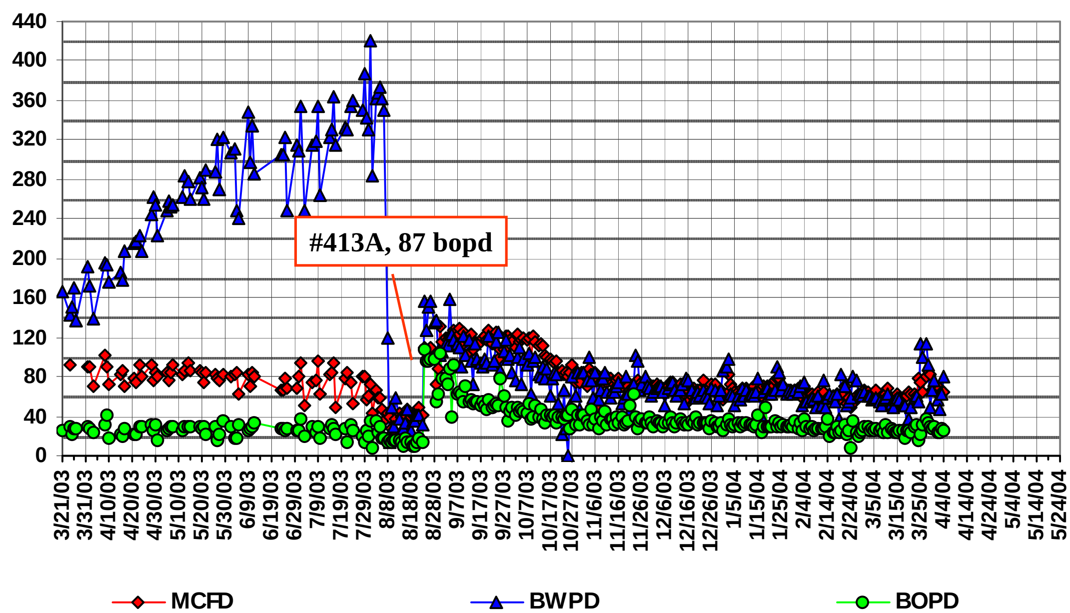


Fig. 12 – Production performance in Tract 4

APPENDIX-A: PROJECT FACT SHEET

CONTRACT TITLE: Preferred Waterflood Management Practices for the Spraberry Trend Area – PUMP Breakout

ID NUMBER: DE-FC26-01BC15274 **B&R CODE:** AC1005000	**CONTRACTOR:** Texas Engineering Experiment Station **ADDR:** 322 Wisenbaker Engineering Research Center College Station, TX 77843
DOE PROJECT MANAGER: **NAME:** Daniel J. Ferguson **LOCATION:** NPTO **PHONE:** 918/ 699-2047 **E-MAIL:** dan.ferguson@npto.doe.gov	**CONTRACT PROJECT MANAGER:** **NAME:** David Schechter **PHONE:** 979/ 845-2275 **FAX:** 979/845-1307 **E-MAIL:** schech@spindletop.tamu.edu
PROJECT SITE **CITY:** College Station **STATE:** TX **CITY:** **STATE:** **CITY:** **STATE:**	**CONTRACT PERFORMANCE PERIOD:** 9/1/2001 to 8/31/2004 **PROGRAM:** Reservoir Life Extension **RESEARCH AREA:** PUMP **PRODUCT LINE:** RLE

CO-PARTICIPANTS:

PERFORMER: Pioneer Natural Resources	**CITY:** Irving	**STATE:** TX	**CD:**
PERFORMER:	**CITY:**	**STATE:**	**CD:**
PERFORMER:	**CITY:**	**STATE:**	**CD:**
PERFORMER:	**CITY:**	**STATE:**	**CD:**

FUNDING (1000'S)	DOE	CONTRACTOR	TOTAL
PRIOR FISCAL YRS	0	0	0
FY 2001 CURRENT OBLIGATIONS	500	1567	2067
FUTURE FUNDS	5	0	5
TOTAL EST'D FUNDS	505	1567	2072

OBJECTIVE: The objective of this project is to design and test different waterflood techniques that have never been utilized in the Spraberry Trend Area. The new waterfloods will align injection wells along the fracture trend with production wells. New injection wells will be drilled that will not be artificially fractured to test whether specific zonal isolation is the primary key. Existing producers with massive hydraulic fracture treatments will be converted to injectors to test whether the hydraulic fractures hinder or aid sweep efficiency. An injection pattern, which is adjacent to, and on-trend with a section containing a majority of plugged wells will be dedicated to investigating whether there is still mobile oil in the vicinity of old, abandoned wells and whether this oil can be swept and captured in current producing wells. A comprehensive economic analysis will be provided to identify the preferred management practices and to transfer the information to all Spraberry operators so that other operators can initiate water injection based on the results of the Spraberry Shackelford Unit Field Demonstration.

PROJECT SUMMARY

Background:

Regions with greatest potential – the naturally fractured Spraberry Trend Area is one of the largest reservoirs in the domestic U.S. and is the largest reservoir in area extent in the world. Production from Spraberry sands is found over a 2,500 sq. mile area and Spraberry reservoirs can be found in an eight county area in west Texas. Over 150 operators produce 65,000 barrels of oil per day (bopd) from the Spraberry Trend Area from more than 9,000 production wells. Recovery is poor, on the order of 7 – 10% due to the profoundly complicated nature of the reservoir, yet billions of barrels of hydrocarbons remain. We estimate over 15% of remaining reserves in domestic Class III reservoirs are in Spraberry Trend Area reservoirs. This tremendous domestic asset is a prime example of an endangered hydrocarbon resource in need of immediate technological advancements before thousands of wells are permanently abandoned.

Integrate solutions to technological, regulatory and data constraints – the technological and data constraints have resulted in a general lack of confidence for water injection in the Spraberry Trend. Regional variations in geology combined with highly permeable, stress-sensitive fractures and very low matrix permeability create intensely difficult technical challenges. The fact that several waterflood projects over the course of 40 years have failed to provide an adequate and definitive answer regarding the technical and economic feasibility of waterflooding is a testament to technological and data constraints. Simply by the magnitude of the number of wells, management practices are of paramount importance when optimizing water injection in the Spraberry Trend Area. Many companies operate wells outside the Spraberry Units and several zones are typically commingled. Regulatory and data acquisition constraints are a serious issue and pose a great challenge for waterflood operations in Spraberry reservoirs. Proper reservoir engineering in a reservoir that is so large and communicates, via the fractures, over great distances poses a complicated technological and data management constraint. Reservoir engineering, by definition, requires precise injection, production and pressure data. Acquisition and control of this data has always been a constraint to providing the optimum method for water injection. The result is large volumes of oil that could have been recovered via water injection that remain untapped. We believe we have reached a fundamental understanding of Spraberry reservoirs. Individual Spraberry wells will never produce large volumes of oil, however, if past constraints, barriers to production and a general lack of confidence in waterflooding can be overcome, even modest improvements in well productivity multiplied over such a vast area would result in rapid increase in production.

Field demonstration – a low risk, high potential demonstration of technological innovations will be completed within two years. A waterflood demonstration is proposed by the Harold Vance Department of Petroleum Engineering in the Spraberry Shackelford Unit with Pioneer Natural Resources as the operator and Exxon/Mobil as supporting owner. This field demonstration will be carefully monitored and may result in a rapid increase in Spraberry production.

ACCOMPLISMENTS:

Task 1.0 Shackelford and Germania Unit Historical Review

- Reconstruction of Shackelford and Germania Injection/Production Data
- Development of production and database using Oil Field Manager (OFM)
- Development of field management software (FMS)
- Review well bore status in Shackelford Unit

Task 2.0 Review Midkiff Pilot

- Review of Upper and Lower Pilots in the Spraberry Area

Task 3.0 Develop production and database using OFM and Field Data Management software

Task 4.0 Development of optimum injection well patterns based on simulation

- Improving Waterflood and CO2 Pilot Performance in the Naturally Fractured Spraberry Trend Area, West Texas

Task 5 Refine sub-surface maps for 1U and 5U oil saturated intervals

- Germania Unit Characterization using an Analog Field and Old Cased Hole Neutron

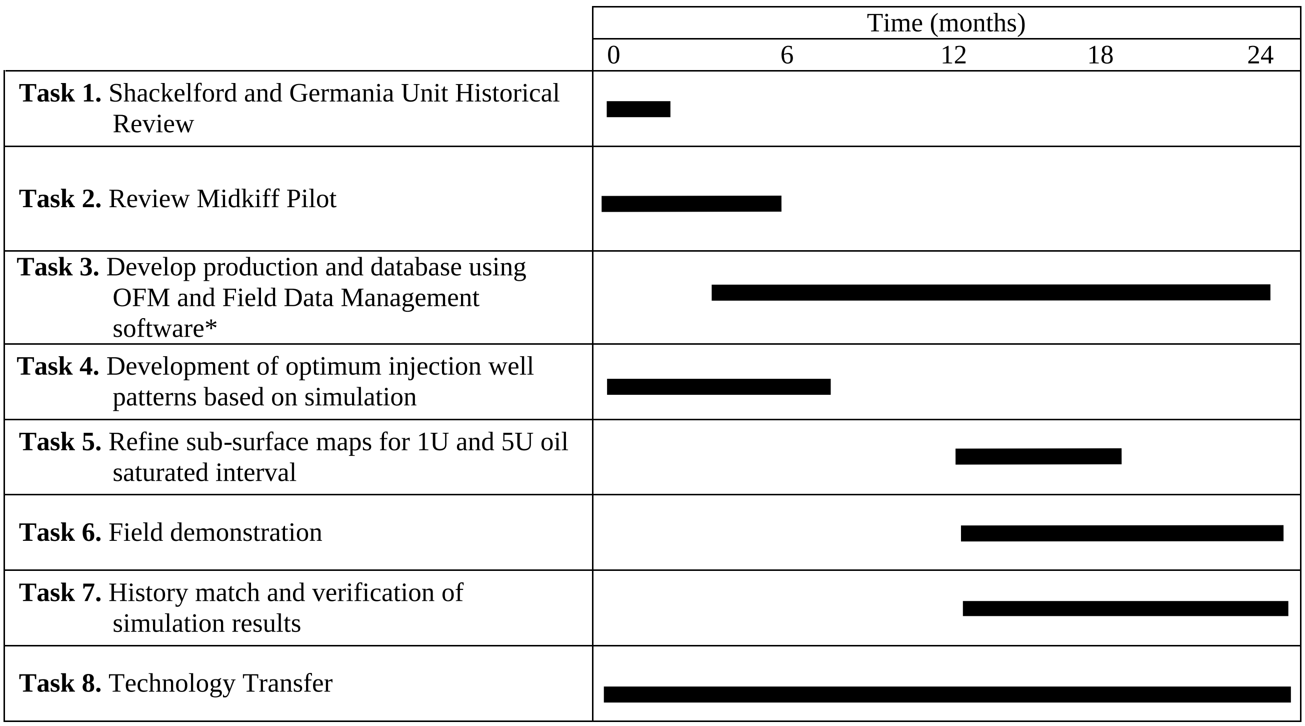
Task 6 Field demonstration

- Modify strategy based on response and development of expansion plans
- Germania Unit rate forecasting based on other waterflood pilots in the Spraberry Area
- Evaluation of E.T O'Daniel Pilot
- Evaluation of Waterflooding Performance in Germania Spraberry Unit
- Analysis of Waterflood performance on daily basis

Task 7 History match and verification of simulation results

- Improving Waterflood Performance in the Naturally Fractured Spraberry Trend Area

SCHEDULED MILESTONES:



*** Software developed during this project**

Accomplished Milestones
Proposed Milestones

REPORTS:

1. Putra, E. and Schechter, D.S.: "Review of Upper and Lower Pilots in The Spraberry Area," report included in "Preferred Waterflood Management Practices for the Spraberry Trend Area – PUMP" Semi-Annual Report (DOE Contract No.: DE-FC26-01BC15274), Sept 1, 2001- March 1, 2002.
2. Putra, E., and Schechter, D.S.: " Germania Unit Rate Forecasting Based on Other Waterflood Pilots," report included in "Preferred Waterflood Management Practices for the Spraberry Trend Area - PUMP" First Annual Report (DOE Contract No.: DE-FC26-01BC15274), April 1- Sept 31, 2002.
3. Lakshman, G., Putra, E., and Schechter, D.S.: "Evaluation of Current E.T O'Daniel CO2 Pilot," report included in "Preferred Waterflood Management Practices for the Spraberry Trend Area - PUMP" First Annual Report (DOE Contract No.: DE-FC26-01BC15274), April 1- Sept 31, 2002.

4. Olumide, B.A.: “Germania Unit Characterization using an Analog Field and Old Cased Hole Neutron,” report included in “Preferred Waterflood Management Practices for the Spraberry Trend Area – PUMP” Semi-Annual Report (DOE Contract No.: DE-FC26-01BC15274), April 1 – Sept 31, 2003.
5. Hernandez, E.: “Evaluation of Waterflooding Performance in Germania Spraberry Unit,” report included in “Preferred Waterflood Management Practices for the Spraberry Trend Area – PUMP” Semi-Annual Report (DOE Contract No.: DE-FC26-01BC15274), Oct. 1, 2003 – March 31, 2004.

TECHNOLOGY TRANSFER ACTIVITIES:
Presentations

On February 17, 2004, we presented “Waterflood and CO_2 Performance in the Naturally Fractured Spraberry Trend Area,” presented at SPE Gulf Coast Section, February 17, 2004.

On October 6, 2003, we (Galaviz, J.) presented “Low-Rate Water Injection Enhances Recovery In The Naturally Fractured Spraberry Trend Area” at the international student paper contest at 2003 SPE Annual Technical Conference, CO. Mr. Galaviz won the first price.

On September 18, 2003, we presented the talk “Waterflood and CO_2 performance in the Naturally Fractured Spraberry Trend Area,” at the Statoil Research Summit 2003, Trondheim, Norway.

On June 2003, we presented the Short Course for Saudi Aramco in Al Khobar, Saudi Arabia – “Reservoir Characterization, Engineering and Enhanced Oil Recovery in Naturally Fractured Reservoirs.”

On April 2003, we presented “Fracture Characterization and Pilot Performance in the E.T. O’Daniel Unit Spraberry Trend Area, West Texas,” at the University of Texas at Austin invited lecture for Society of Petroleum Engineering Chapter and Graduate Seminar.

On March 2003, we presented the Short Course for UNAM/PEMEX in Mexico City, Mexico – “Reservoir Characterization and Engineering in Naturally Fractured Gas and Oil Reservoirs – Part II.”

On June 13, 2002, we presented the "Imbibition and its Relevance to Waterflood Performance in the Naturally Fractured Spraberry Trend Area," at the Rice University and University of Houston invited lecture for Society of Petroleum Engineering Chapter, Duncan Hall, Rice University.

On October 2001, we presented the Short Course for UNAM/PEMEX (National Petroleum Company of Mexico) in Mexico City, Mexico – “Reservoir Characterization and Engineering in Naturally Fractured Gas and Oil Reservoirs - Part I.”

On February 2001, we presented the Short Course for for UNAM/PEMEX in Mexico City, Mexico – “Reservoir Characterization and Engineering in Naturally Fractured Gas and Oil Reservoirs – Part I.”

Papers and Publications

1. Schechter, D.S., Putra, E., Baker, R.O., Knight, W.H., McDonald, W.P., Leonard, P., and Rounding, C.: “CO_2 Pilot Design and Water Injection Performance in the Naturally Fractured Spraberry Trend Area, West Texas,” paper SPE 71605 presented at the 2001 Annual Technical Conference and Exhibition, New Orleans, LA, September 30–October 3.
2. Baker, R.O., Bora, R., Schechter, D.S., McDonald, P., Knight, W.H., Leonard, P., and Rounding, C.: “Development of a Fracture Model for Spraberry Field, Texas USA, ” paper SPE 71635 presented at the 2001 Annual Technical Conference and Exhibition, New Orleans, LA, September 30–October 3.

3. Schechter, D.S., Putra, E., Knight, W.H., Leonard, P., and Baker, R.O.: "Improving Waterflood and CO2 Pilot Performance in the Naturally Fractured Spraberry Trend Area, West Texas," paper presented at the 2002 Conference on Naturally Fractured Reservoirs, Oklahoma, June 3-4.
4. Chowdhury, T., Dabiri, G., Putra, E., and Schechter, D.S.: "Improving Waterflood Performance in the Naturally Fractured Spraberry Trend Area," paper presented at the 2002 Conference on Naturally Fractured Reservoirs, Oklahoma, June 3-4.
5. Alfred, D., Putra, E., and Schechter, D.S.: "Transcending Conventional Log Interpretation – A More Effective Approach for Spraberry Reservoir," paper presented at the 2002 Conference on Naturally Fractured Reservoirs, Oklahoma, June 3-4.
6. Galaviz, J., Schechter, D.S. and Putra, E.: "Low-Rate Water Injection Enhances Recovery in the Naturally Fractured Spraberry Trend Area," paper SPE presented at 2003 International Student Paper Contest, Denver, Colorado, 6–8 October.

Internet Postings on the Project and Software to Download
A description of our research group can be found at the following Petroleum Engineering Texas A&M Website: http://pumpjack.tamu.edu/faculty/schechter/baervan/homepage.html. The site lists the publications of our group and allows downloads of several papers, reports, and presentations.

CONTACT INFORMATION:

NAME: David Schechter
PHONE: 979/ 845-2275
FAX: 979/845-1307
E-MAIL: schech@spindletop.tamu.edu

DIGITAL PICTURES: