RESERVOIR CHARACTERIZATION, PERFORMANCE MONITORING OF WATERFLOODING AND DEVELOPMENT OPPORTUNITIES IN GERMANIA SPRABERRY UNIT

A Thesis

by

ERWIN ENRIQUE HERNANDEZ HERNANDEZ

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

May 2004

Major Subject: Petroleum Engineering

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Approved as to style and content by:

David Schechter (Chair of Committee)	Duane McVay (Member)
Richard Gibson (Member)	Stephen Holditch (Head of Department)

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ABSTRACT

Reservoir Characterization, Performance Monitoring of Waterflooding, and Development Opportunities in Germania Spraberry Unit. (May 2004)

Erwin Enrique Hernandez Hernandez, B.S., Universidad del Zulia, Venezuela

Chair of Advisory Committee: Dr. David Schechter

The Germania Unit is located in Midland County, 12 miles east of Midland, Texas and 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 and 10.5 billion barrels of oil originally in place. 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. Natural fractures existing over a regional area have long been known to dominate all aspects of performance in the Spraberry Trend Area. Two stages of depletion have taken place over 46 years of production: Primary production under solution gas drive and secondary recovery via water injection through two different injection patterns. The cumulative production and injection in Germania as of July 2003 were 3.24 million barrels and 3.44 million barrels respectively and the production level is 470 BOPD through 64 active wells with an average rate per well of 7.3 BOPD and average water cut of 60 percent. This performance is considered very low and along with the low amount of water injected, waterflood recovery has never been thoroughly understood.

In this research, production and injection data were analyzed and integrated to optimize the reservoir management strategies for Germania Spraberry Unit. This study addresses reservoir characterization and monitoring of the waterflood project with the aim of proposing alternatives development, taking into account current and future conditions of the reservoir.

Consequently, this project will be performed to provide a significant reservoir characterization in an uncharacterized area of Spraberry and evaluate the performance of the waterflooding to provide facts, information and knowledge to obtain the maximum economic recovery from this reservoir and finally understand waterflood management in Spraberry. Thus, this research describes the reservoir, and comprises the performance of the reservoir under waterflooding, and controlled surveillance to improve field performance.

This research should serve as a guide for future work in reservoir simulation and reservoir management 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 pattern consisting of 6 injection wells aligned about 36 degrees respect to the major fracture orientation. This incremental is based in both extrapolations and numerical simulation studies conducted in Spraberry.

DEDICATION

I dedicate this work to all members of my family who are my motivation and inspiration to successfully achieve my goals.

This thesis is also dedicated to my friends for their continuous support during both my studies and career.

ACKNOWLEDGEMENTS

My gratitude goes to my family members for their love and valuable support. I express my most sincere gratitude to Dr. David Schechter, Associate Professor of the Harold Vance Department of Petroleum Engineering at Texas A& M University, for his support and guidance that led to the successful completion of this work. I express my thanks to Dr. Duane McVay, for his cooperation and support. I also express my appreciation and thanks to Dr. Richard Gibson from the Geology and Geophysics Department. I acknowledge Pioneer Natural Resources for providing the field data for the development of this research. It is also necessary to acknowledge people from the Venezuelan Student Association who have been like a family in College Station. I also would like to acknowledge Petroleos De Venezuela (PDVSA) for their support and for sponsoring my studies at Texas A&M University and Schlumberger for providing the software used during the development of this research.

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CHAPTER I
INTRODUCTION

The Germania Unit is located in Midland County, 12 miles east of Midland, Texas (**Fig.1**) and covers an 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 and 10.5 billion barrels 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[1].

The 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 improving in the performance.

This thesis follows the style of SPE *Journal of Petroleum Technology.*

The 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 3.44 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 75 percent. Then, two infill drilling programs took place increasing the numbers of producer wells from 20 to 98 in a period of 10 years. The numbers of active wells as of July of 2003 is 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 3.24 million barrels and 3.44 million barrels respectively. In February 2003 the operator began a new water injection project (under a pattern consisting of six wells forming and angle of 36 degrees respect to major fracture trend) by converting three wells to water injectors, returning two wells to water injectors and drilling a new injector well (**Fig. 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 3.242 million barrels.

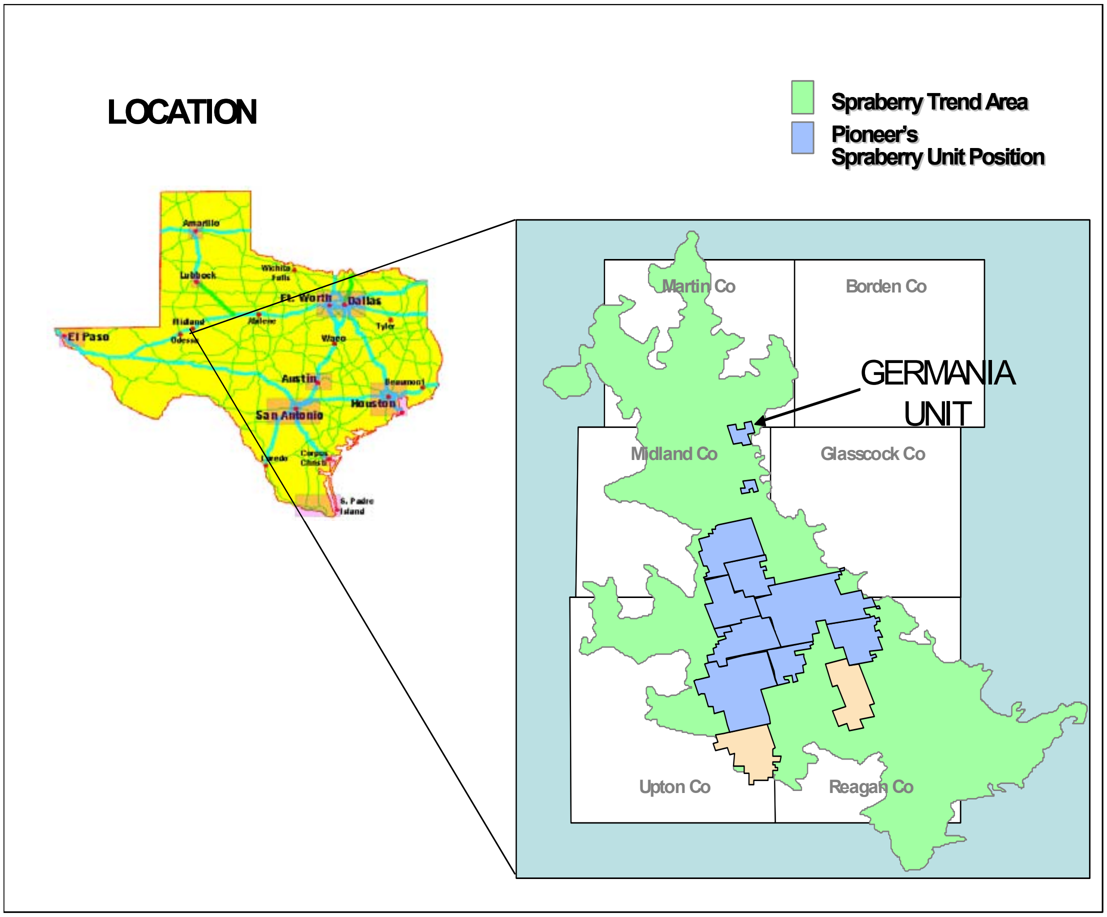

Fig. 1– Location of Germania Spraberry Unit.

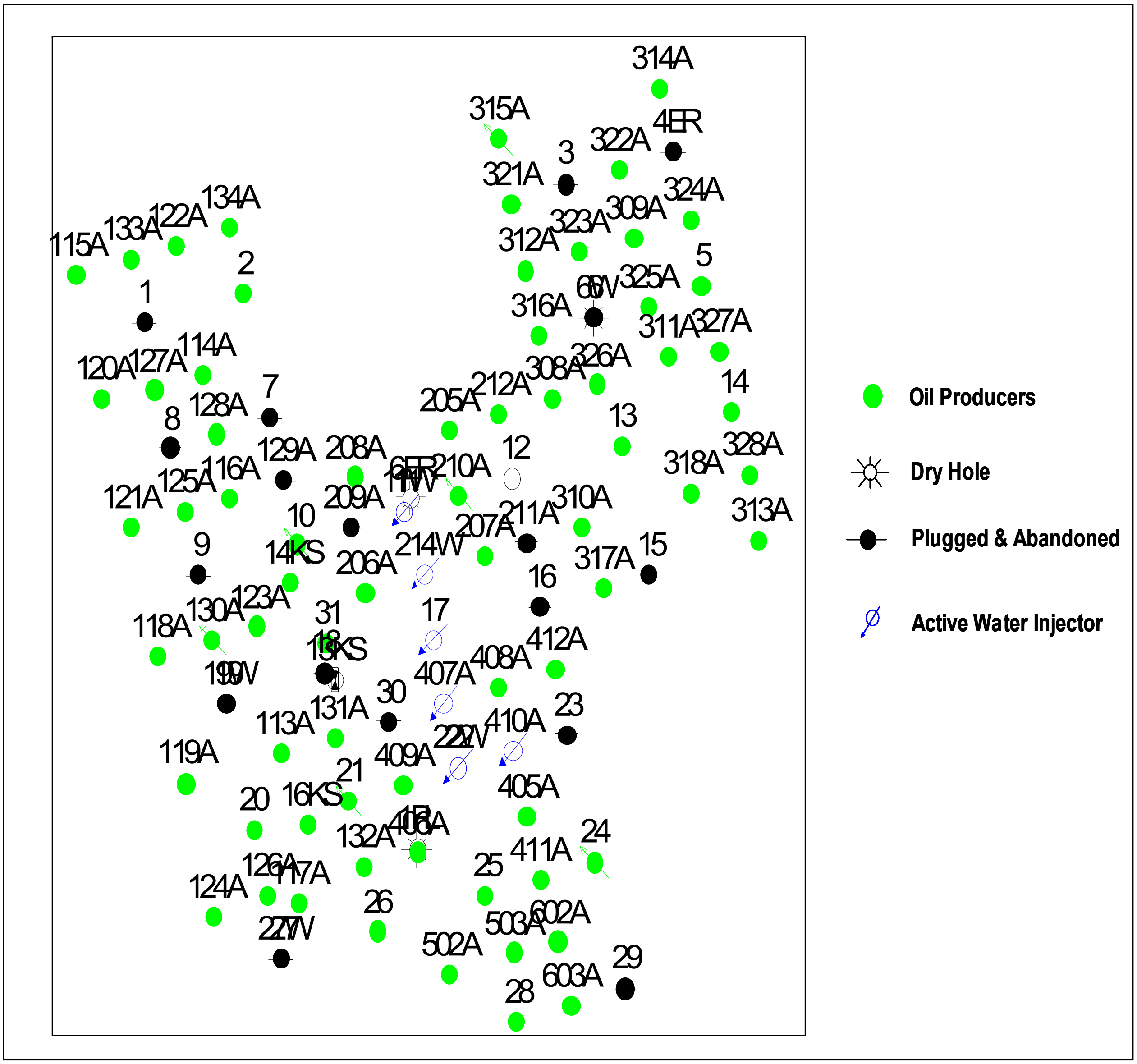

Fig. 2 – Location of New Water Injectors Wells in Germania Spraberry Unit.

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.

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 improving performance. 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. This can be done by using bubble maps of cumulative oil production.

4. Provide possible fracture orientation and variations from area to area through Spraberry 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.

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^{TM}), 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, and PVT analyses. 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.

CHAPTER II
REVIEW OF GEOLOGY

The Spraberry formation of the Midland basin was deposited during the Leonardian age in the Permian era and represents one of the largest oil accumulations in terrigenous-clastic, slope- basin in the world bearing between 8.9 billion barrels and 10.5 billion barrels of oil originally in place (OOIP). It also comprises one of the largest targets for additional recovery from terrigenous-clastic reservoirs.

Since its discovery in 1949, the area has been subdivided into three main intervals, the lower, middle, and the upper Spraberry formations. Tyler and Gholson further subdivided the formation into pay units. Six of the units identified in the area are found in the Upper Spraberry and two in the lower Spraberry. Of the six units identified in the Upper Spraberry, only two (1U and 5U) are considered as reservoir quality rock capable of making significant production contributions from a commercial point of view as shown in **Fig. 3**. Most of the producer wells are producing from the upper interval (1U) and the injectors have been completed in both upper and lower intervals.

The lower and upper Spraberry are mainly composed of terrigenous clastics. The lower Spraberry is approximately 120 ft. thick and comprises three stacked operational units and has low porosity and permeability.

Geologic History

Since its discovery, the Spraberry Unit has been widely studied and considered as a very important oil target in the Spraberry-Dean play. Some important events reported in the literature are crucial for the development of conceptual models for fracture and hydrocarbon distribution. For example, information and knowledge of the events and depositional environments in the Midland basin is the key to understand the distribution of lithologies and structural settings.

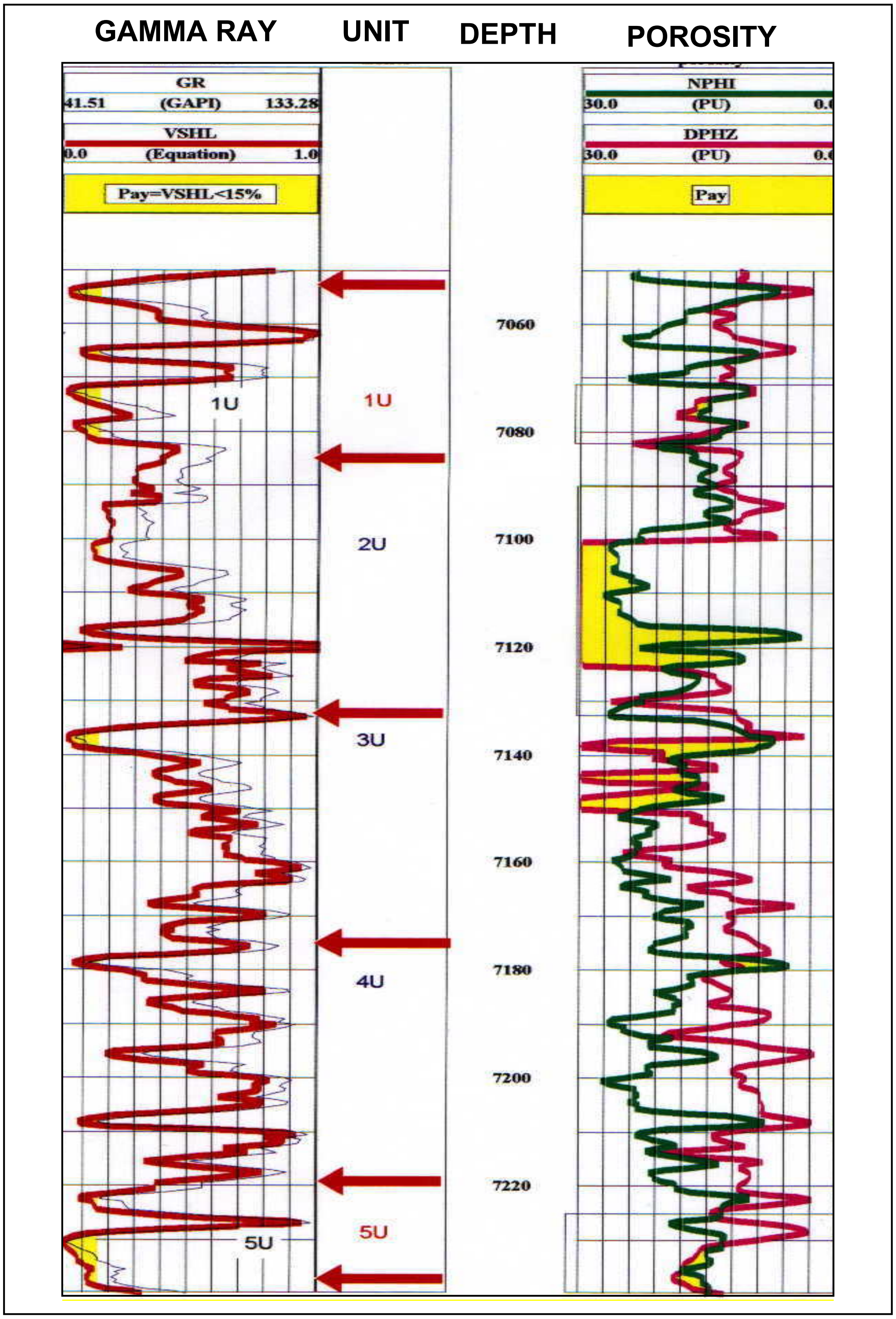

Fig. 3 – Type log for Upper Spraberry Interval. Well GSU-1.

Stratigraphy of the Spraberry Formation

The Spraberry formation is a Leonardian lithostratigraphic formation where terrigenous clastics of the operational units form two main types of vertical sequence: (1) discrete, upward-fining intervals exhibiting a bell gamma-ray log shape and (2) upward-coarsening intervals having a funnel gamma-ray log shape. The latter either occur as discrete units or are stacked in upward-thickening sequences. Stratigraphic distribution, gamma-ray log shape, textural vertical sequence, and genetic relations of the different units and bounding shales, and carbonates were used to divide the Spraberry Formation into the upper, middle, and lower Spraberry[1].

The lower and upper Spraberry are mainly composed of terrigenous clastics. The lower Spraberry is approximately 120 ft. thick and comprises three stacked operational units, which are called 1L, 2L, and 3L. Units 2L and 3L form an upward-thickening sequence. The upper formation is approximately 120 ft. thick and comprises six stacked units (1U-6U) that form two successive upward-thickening sequences[1].

The thickest beds of sandstone and siltstone occur in the upper parts of upward-thickening sequences. The middle Spraberry is composed of shale and carbonate mudstone bounding sandstone and siltstone.

Paleographic Setting

Interpretations of Permian paleography of the Midland basin indicate that the Spraberry formation was deposited in a relatively deep cratonic basin. Terrigenous clastics of the Spraberry Formation accumulated in basinal wedges and elongated submarine fans. These terrigenous clastics range from submarine fans to basin-plain deposits. In some areas of the Midland basin, they are mid-fan, meandering-channel, and overbank deposits, as characterized by Haner in 1971 and modified by Berg in1986. Haner's model shows channels evolving downfan from entrenched (inner fan) to meandering (midfan) to braided (outer fan). The depositional setting described by Yale in 1986 is comparable to radial and poorly efficient fans having braided suprafan-lobe channels and lacking well-developed fan-fringe deposits[1].

Saline-density underflows and turbidity currents transported sandstone and siltstone from adjacent shelf margins. Terrigenous clastics were transported from (1) the north and northwest along submarine channels in Hockey, Lubbock, Yoakum, and Terry counties that tapped hypersaline lagoons of the Northwest Shelf and (2) the east and northeast along channels in Garza, Borden, and Reagan Counties, that drained lagoons of the Eastern Shelf. Turbidite reservoirs in the area were deposited from the north[1].

Hydrocarbons in the Spraberry Formation

Some studies suggest that oil in the Spraberry formation occurs mainly in the intensely fractured shale, rather than in massive siltstones, which were considered the more unproductive part of the play and therefore they were not regarded as intensely fractured. However, it is believed that only 1 to 2 percent of the oil occurs in fractures of the Spraberry formation, and natural fractures increase effective porosity by only 0.057 percent at most. In addition, the oil storage capacity is only 0.35 percent, compared to the 99.65-percent capacity of the matrix. Thus, oil stored in matrix porosity or sandstones and siltstones, and vertical fractures serve mainly as flow paths or channels to the wells.

The different studies conducted in the area show little or no agreement on the oil-generation capabilities of the Spraberry formation. A study conducted by Wilkinson in 1953 indicated that organic-rich mud of the Spraberry formation generated hydrocarbons in restricted areas of the Midland Basin. According to other study conducted by Houde in 1979, oil in the Spraberry formation is indigenous. Shales interbedded with sandstones in the area have total organic carbon as high as 5 percent, suggesting that they are good to excellent source rocks. According to Galloway and others, the Spraberry formation approaches the optimum self-contained oil-generating factory, providing high-quality source rocks juxtaposed with large volumes of potential reservoirs. However, a study proposed by Horak in 1985 proposed that Leonardian strata are thermally immature which means that Spraberry oil migrated from underlying Wolfcamp source rocks along natural fractures.

Porosity and Permeability

Matrix porosity determined by analyses of cores taken during the development of the Spraberry trend, averages 8 percent according to Wilkinson. Some studies have reported three groups of porosity values: (1) good (14 to 18 percent); (2) fair (10 to 13 percent); and (3) poor (6 to 9 percent). Porosity values average 8.56 percent in the Upper Spraberry. Cores analyzed in this field show that porosity has been reduced by quartz overgrowths and that existing porosity is mainly secondary, resulting from dissolution of carbonate cement[1].

Matrix permeability determined from cores, averages 0.5 md. Effective permeabilities determined from pressure data, range from 2 to 183 md. and average 36 md. In some areas of the trend, the original permeability has been reduced by pressure solution in sandy siltstones, ferroan dolomite cementation in calcareous sandstones and siltstones, and alteration of feldspars to clay.

During the development of the trend, two main groups of sandstone were categorized in terms of reservoir quality: (1) clean sandstones with porosity values ranging from 6 to 18 percent and permeability between 0.002 and 2.5 md. and (2) shaly sandstones having 6 to 12 percent porosity and permeability of 0.01 to 0.4 md.

Fracture Origin

One set of vertical shear of fractures and two sets of vertical extension fractures have been observed in upper Spraberry formations as seen in the core taken in E.T. O'Daniel No. 28 well. Even though only one shear fracture has been observed in the Spraberry formation, the direction of stress that caused the fractures to form can be estimated. The geometry of the shear fracture set and sub-horizontal slickenlines observed in the Midland basin suggests that at the time of failure, the maximum stress was horizontal and trended northeast or northwest. According to a study conducted by Sterling (2000), the most likely period of time when shear fractures have formed was the Laramie Orogeny, between 80 and 40 Ma. Two sets of surface lineaments and fractures, striking northeast and northwest, were observed and described by Stanley et al. in 1951 and Guevara in 1988, and were linked to Spraberry formations fractures by Stanley et al. in 1951.This might indicate that the Spraberry formation fractures must have been formed since the deposition of surface sediments in the cretaceous. Since there is not evidence on whether the maximum compressive stress responsible for the origin of the extension fractures was vertical or horizontal, it is very difficult to determine or estimate the time at which they were formed. The sources of stress that could have lead to extensional fractures during the Laramide orogeney are caused by overlying sediments and horizontal compressive stresses produced by subsidence. The extension fractures may have developed during this time[2].

Influence of Natural Fractures on Oil Production

Many studies have been conducted to understand the Spraberry fracture characteristics. However, the characteristics of the fracture network and its interaction with the supporting matrix framework remains poorly understood.

Fracture opening in cores of the Spraberry formation, average 0.002 inch (0.05 mm.) Production data also indicates that they range from 0.0015 inch (0.04 mm) and fracture spacing is about 2 ft.

The average direction of the main trend of fracture is N56ºE as seen in horizontal core taken in E.T O'Daniel well No. 28 and determined the location of oil producers and water injection wells. However, actual well production did not totally agree with expected production behavior because some areas have shown very poor response after waterflooding and these results suggest that some oil accumulations remain untapped or have been inefficiently drained. Thus, although important, natural fractures do not connect all Spraberry reservoir compartments in the Germania Unit.

CHAPTER III
RESERVOIR PERFORMANCE

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. In 1962 the average water cut increased abruptly from 2 to 35 percent because of mechanical problems (mostly casing leaks) experienced in some wells due to the contact between casings and San Andreas formation (corrosive water-bearing). Water cut by the end of the stage averaged 20 percent (**Fig. 4**). The production of liquid per well averaged 37 BLPD and the average production of oil per day per well was 37 BOPD (**Fig. 5**). 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 July 2003.

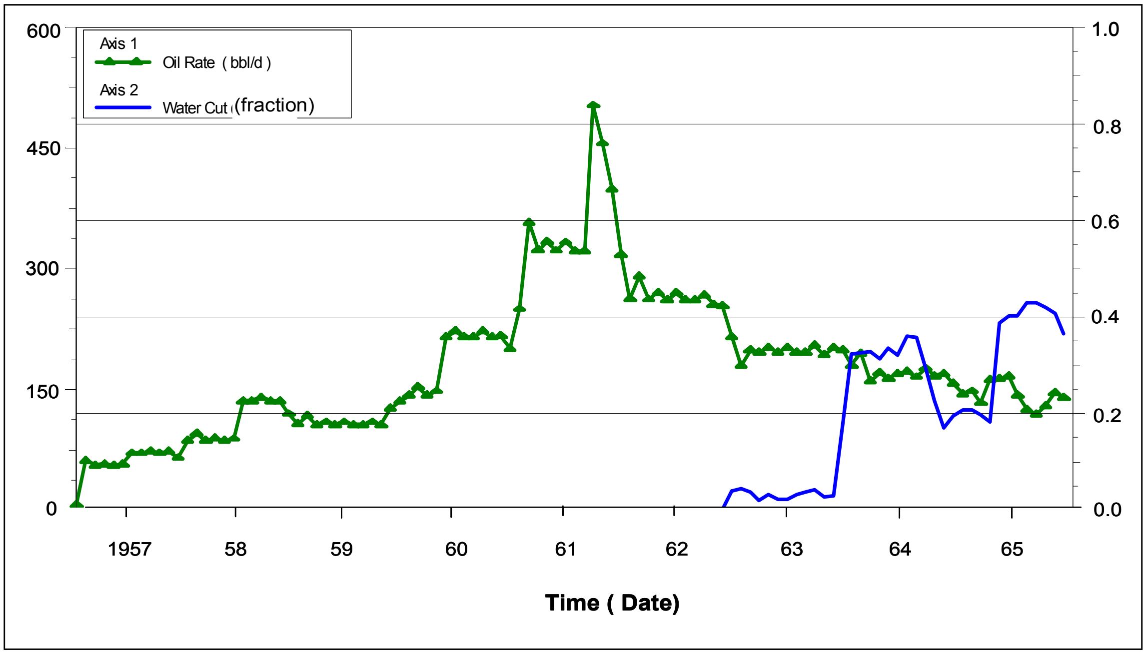

Fig. 4 -Oil Rate and Water Cut During Primary Depletion of Germania Spraberry Unit.

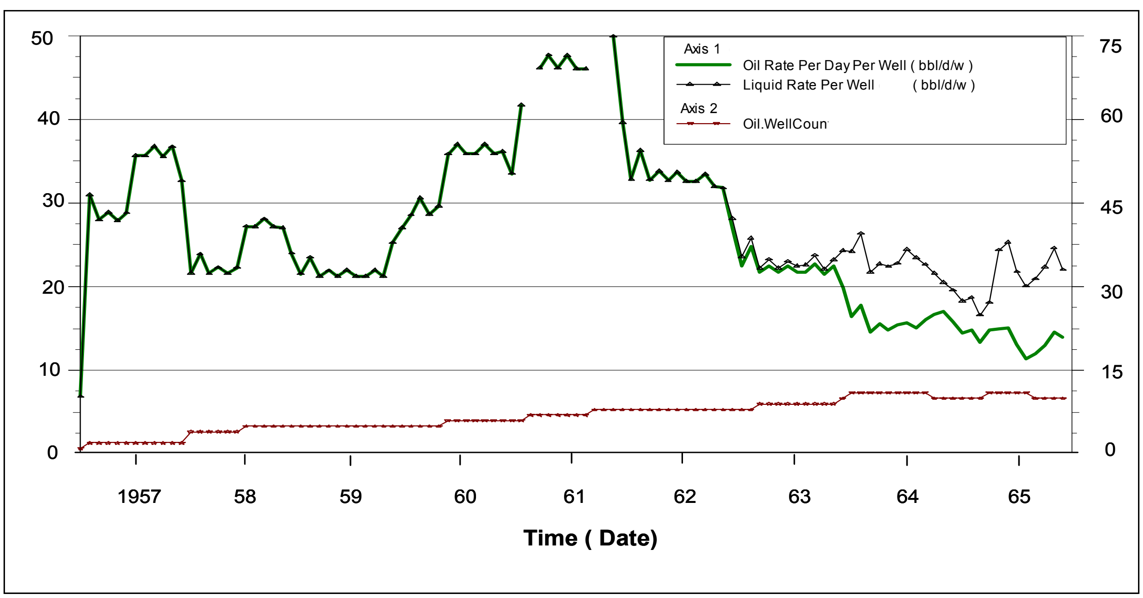

Fig. 5 -Oil Rate per well, Liquid Rate per Well and Active Wells During Primary Depletion for Germania Spraberry Unit.

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. 6**). The cumulative water injection under this period was 3.44 million barrels, the average water injection rate per well was 688 BWPD (**Fig. 7**), and the cumulative water production was 0.95 million barrels of oil.

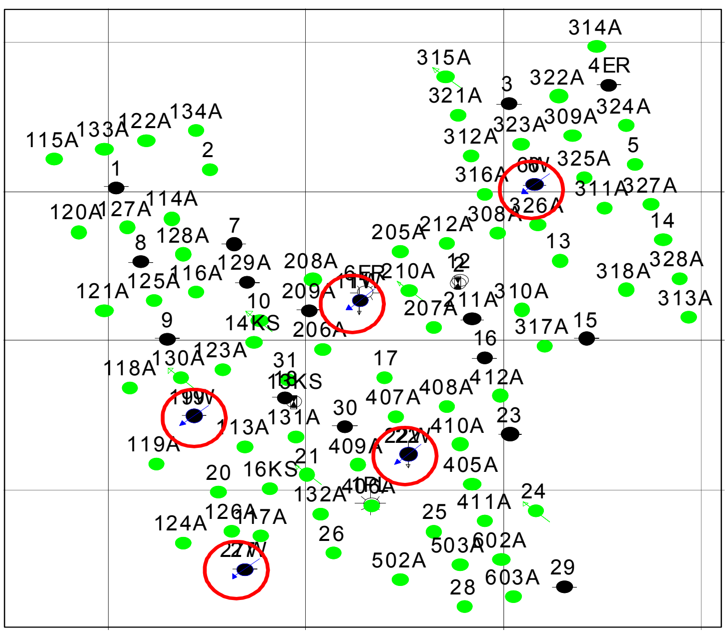

Fig. 6 -Base Map of Germania Spraberry Unit Showing the Wells Injecting Water from 1965 to 1990.

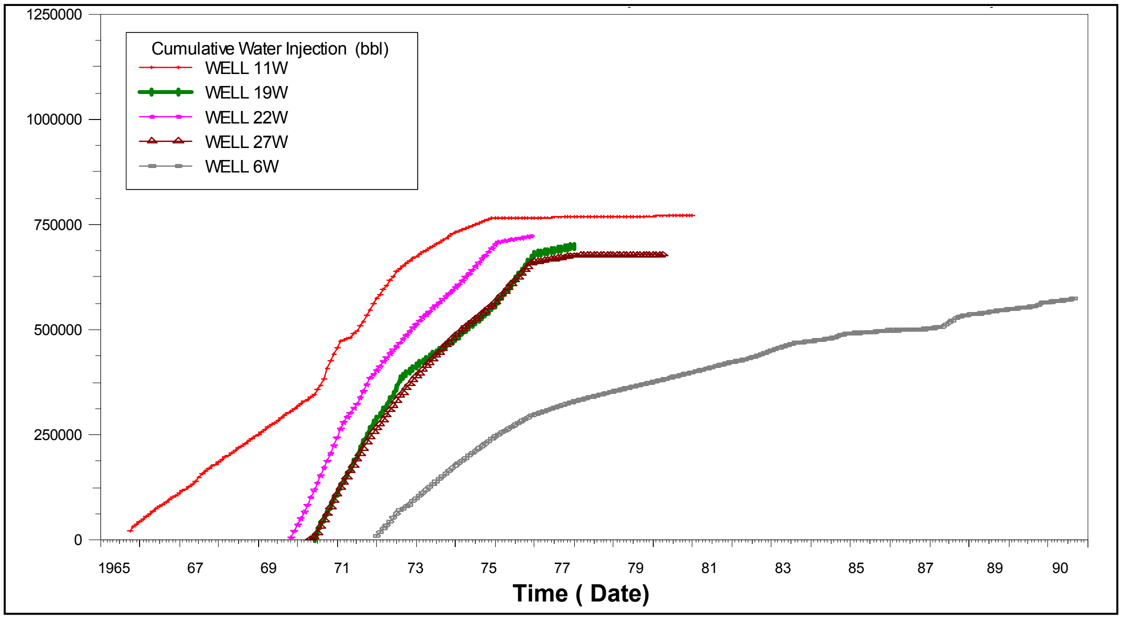

Fig. 7 - Cumulative Water Injection for the Five Wells Injecting from 1965 to 1990.

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 programs 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. 8**).

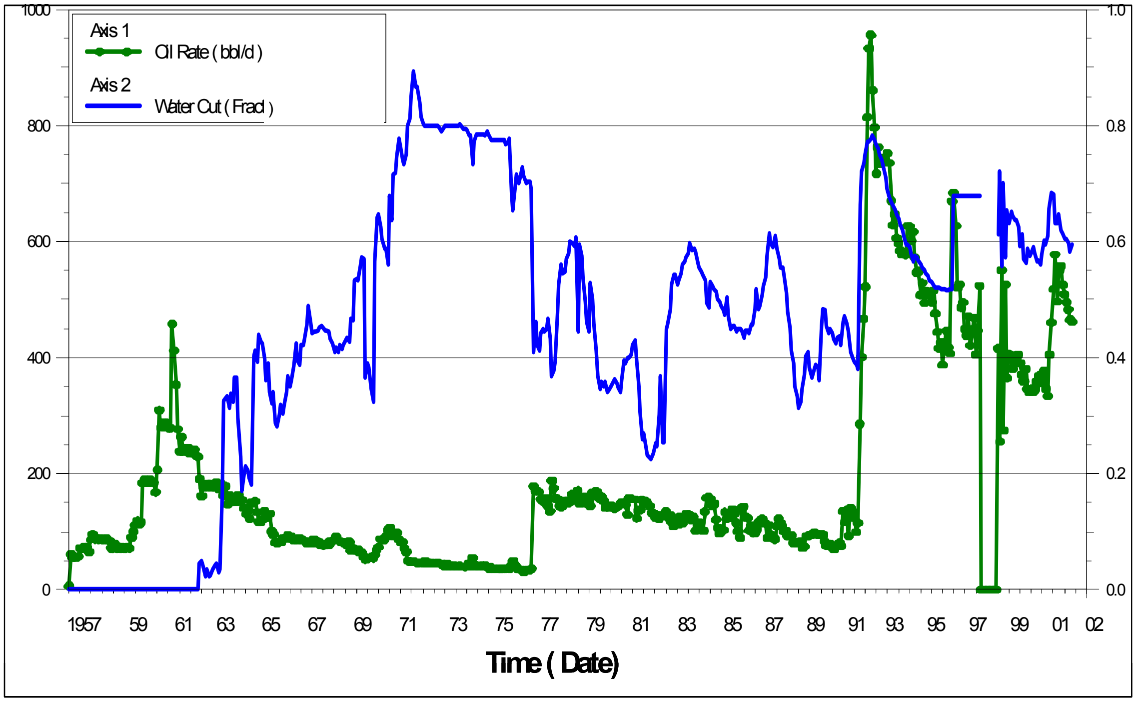

Fig. 8 -Oil Rate and Water Cut during Primary and Secondary Depletion of Germania Spraberry Unit.

The cumulative water production and injection as of June 2003 were 3.24 and 3.44 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. 9**). 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 3.242 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. 10**).

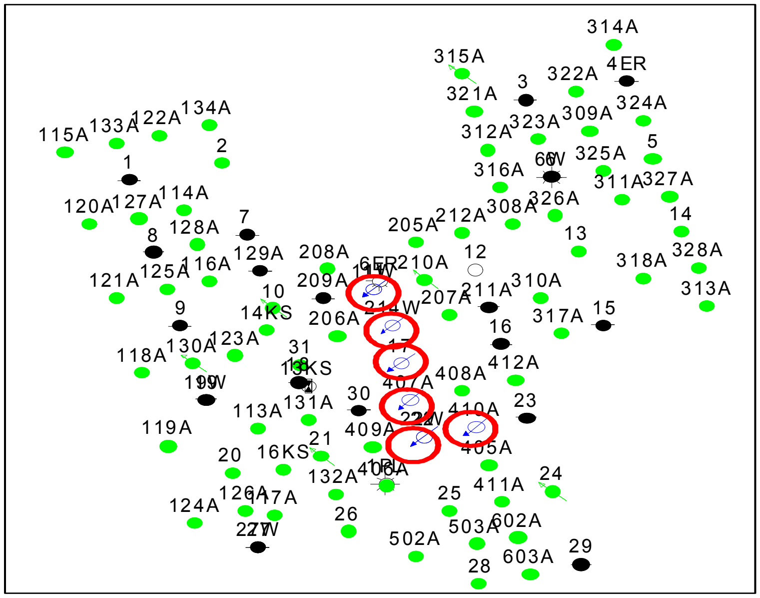

Fig. 9 -Base Map of Germania Spraberry Unit Showing Wells Injecting Water Under the New Injection Pattern (January 2003).

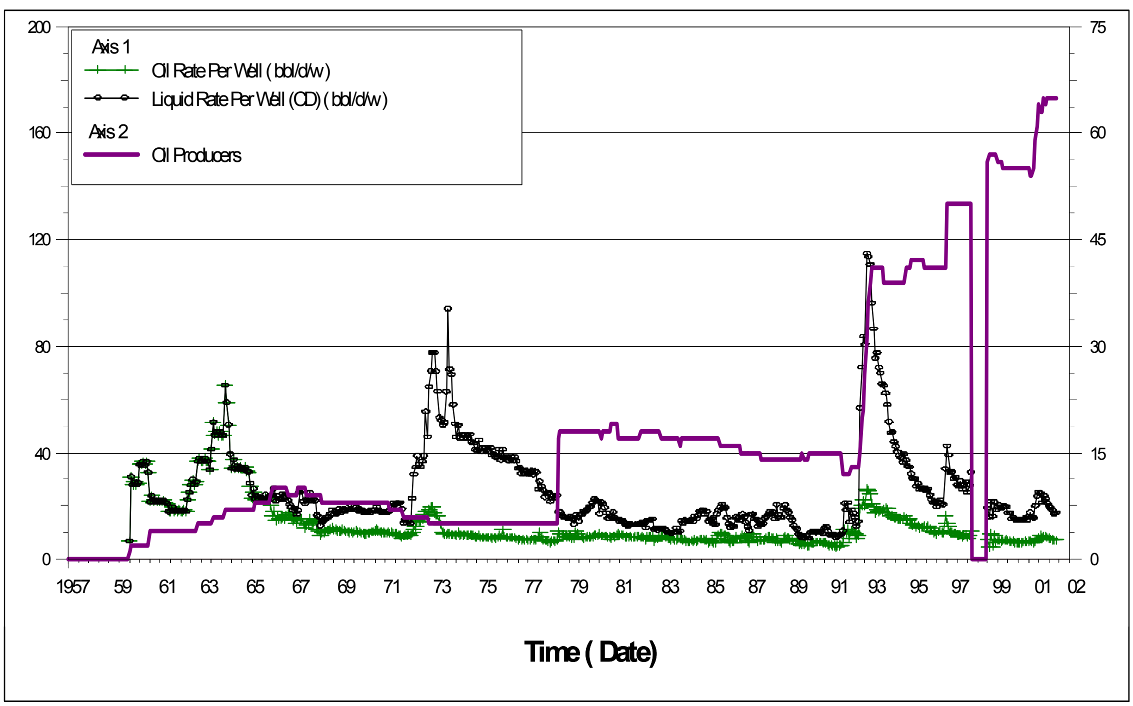

Fig. 10 -Oil Rate per well, Liquid Rate per Well and Active Wells During Primary and Secondary Depletion for Germania Spraberry Unit.

CHAPTER IV
RESERVOIR MONITORING AND SURVEILLANCE SYSTEM

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

Sometimes the actual performance of most fields may not agree with expected performance. 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 under-injection of water 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 performance.

For this, we developed a data base 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 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.

Production Heterogeneity Indexing

In this part we describe a surveillance tool for production data referred to as Production Heterogeneity Index[3] 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:

$$HI\ \ Oil\ \ Rate\ \ = \frac{Oil\ \ \ Rate}{Average\ \ \ \ OilRate} - 1 \quad \text{.......(4.1)}$$

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:

$$HI\ \ Water\ \ \ Rate\ \ = \frac{Water\ \ \ \ Rate}{Average\ \ \ \ WaterRate} - 1 \quad \text{.......(4.2)}$$

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 equation (4.1) and equation (4.2) for every well.

According to the equation (4.1) 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 (4.2).

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.11** 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. 12**) 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.13**).

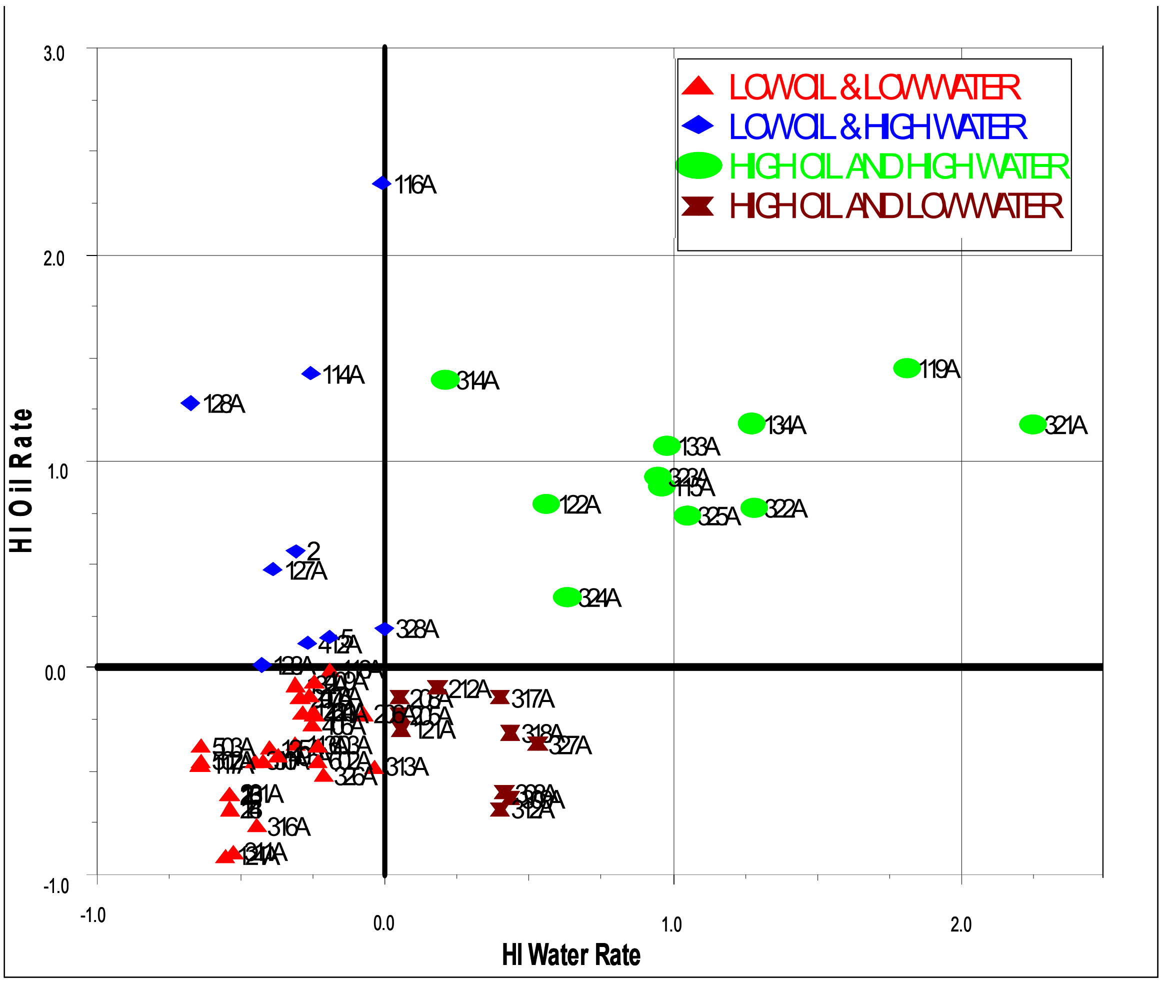

Fig. 11 - Cross-Plot Showing the Production Heterogeneity Index for Oil and Water in 64 Active Wells of Germania Spraberry Unit.

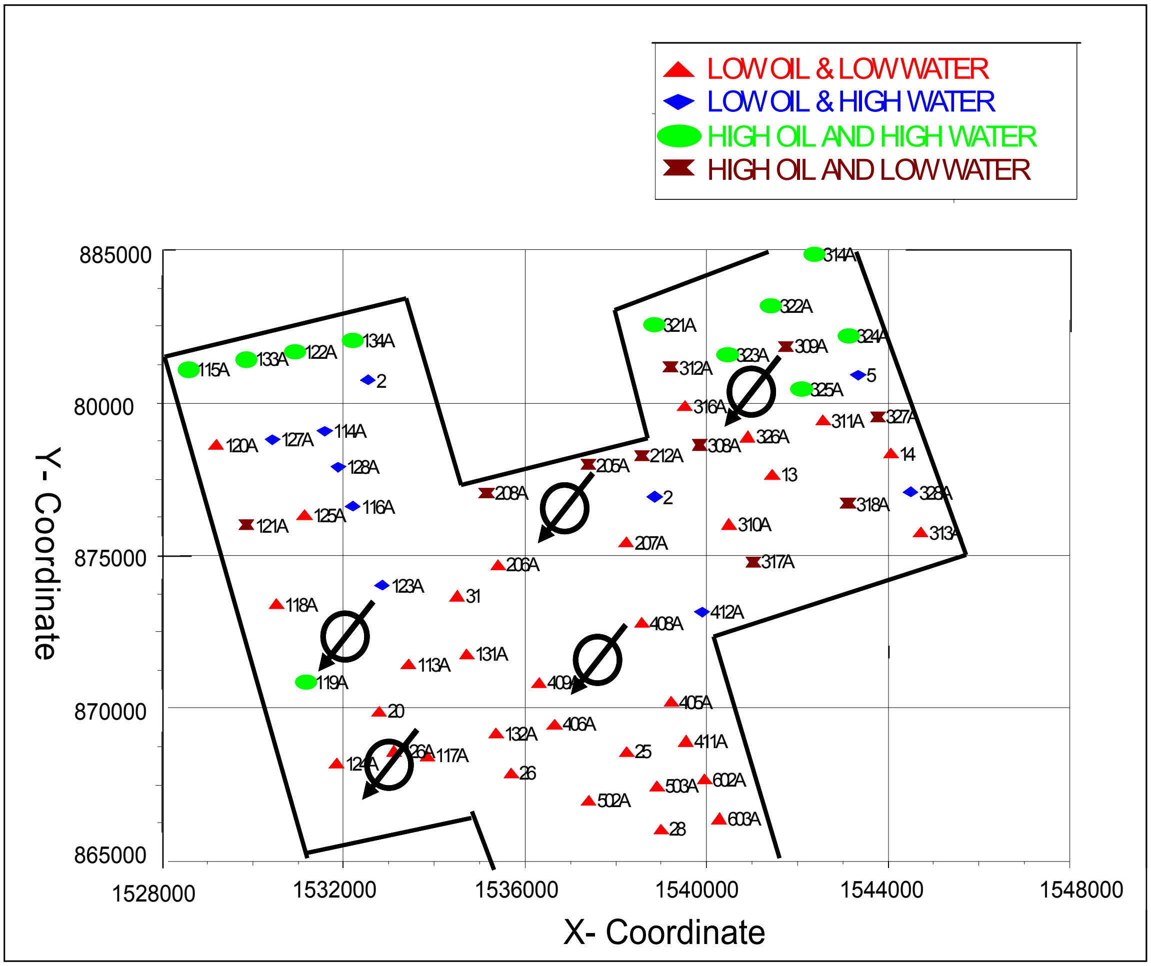

Fig. 12 -Base Map Showing the 64 Active Wells in Germania Spraberry Unit and Its Position with Regards to the Injectors (Old Injection Pattern).

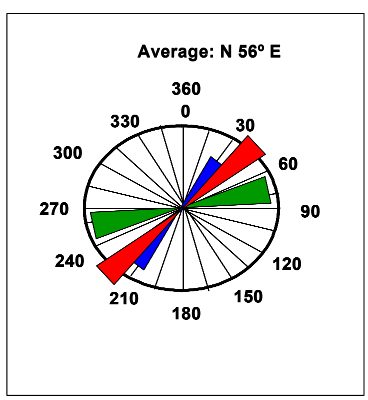

Fig. 13 -Fracture Orientation from Core Analysis.

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 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 can be summarized in **Table 1.**

Table 1– Category of Active Wells Based on 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 (Water control)	Form a line parallel to the new injection pattern

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:

$$VRR = \frac{qWi\ B_W}{q_O\ B_o + qW\ B_W + q_O(GOR - Rs)Bg} \qquad \text{.......} (4.3)$$

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. 14**). 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. 15**), 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.

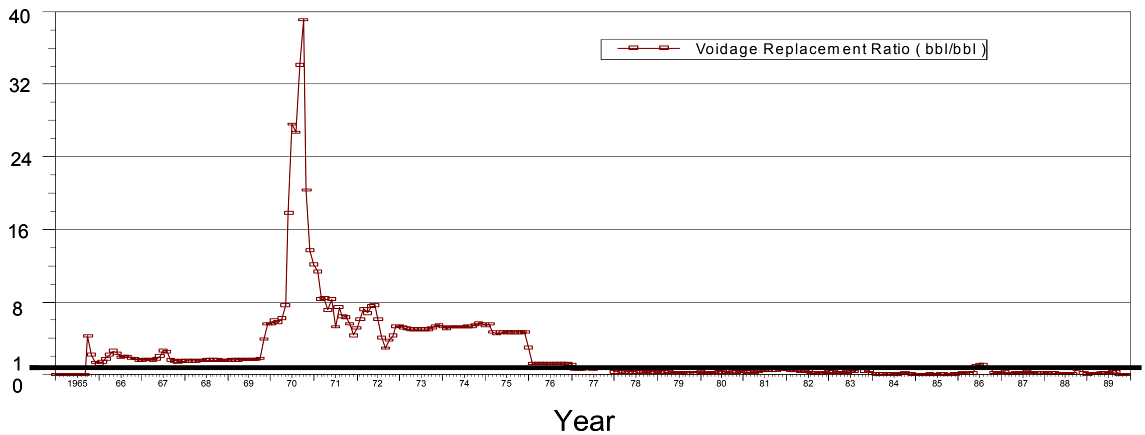

Fig. 14 -Voidage Replacement Ratio for the First Period of Injection

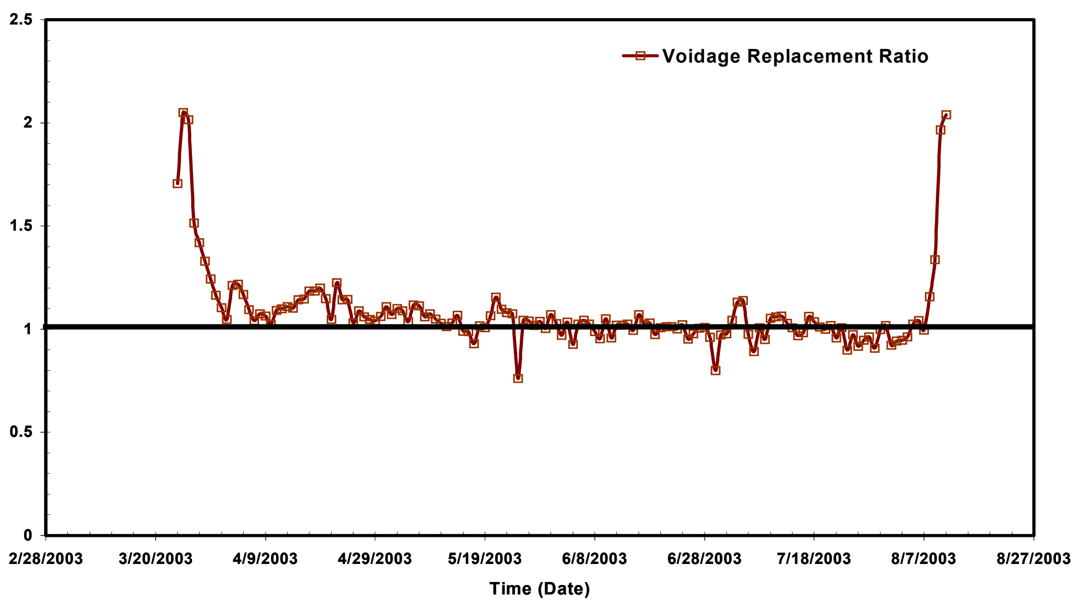

Fig. 15 -Voidage Replacement Ratio for the Second Period of Injection

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 assumed to be approximately 50 degrees east of north (N 50° E). Through the use of production plots and bubble maps we tried to establish the behavior of the production and support this trend and corroborate with horizontal core in the O'Daniel unit. 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. 16**

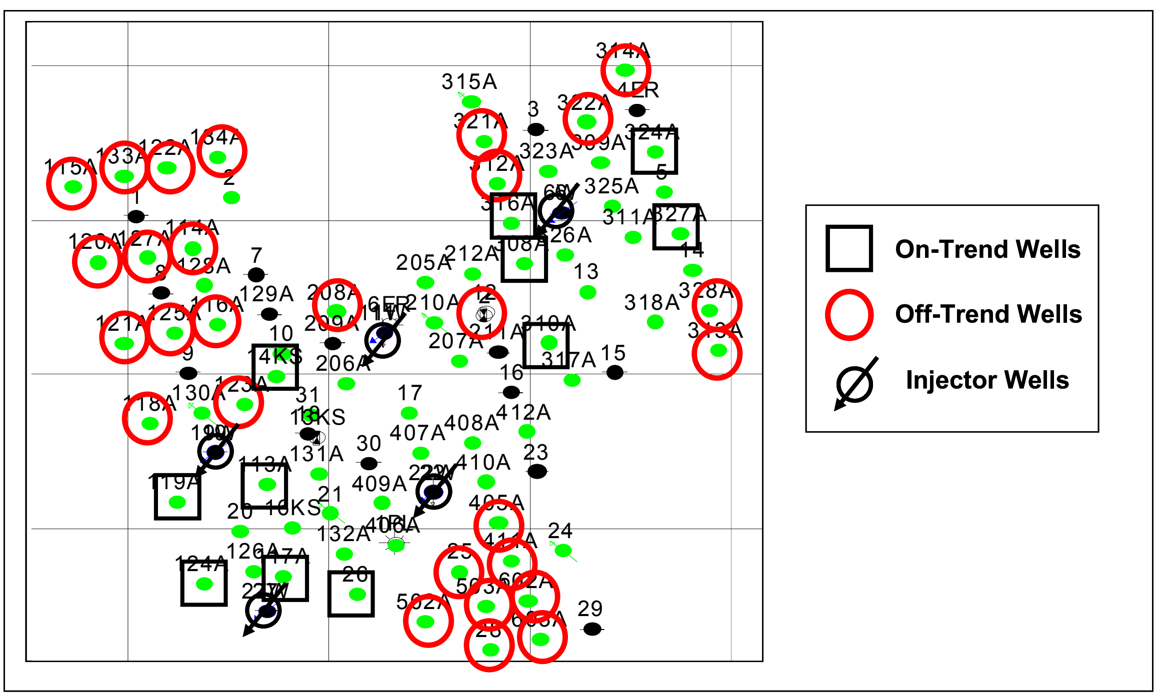

Fig.16 -Base Map Showing the On-trend and Off-trend Wells

Fig. 17 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. 18** 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 the flow is greatly influenced by the wettability of the rock. This also corroborates that the fracture orientation is N 56° E. The performance of both on-trends and off-trends has showed oil bank followed by sharp breakthrough of the water front.

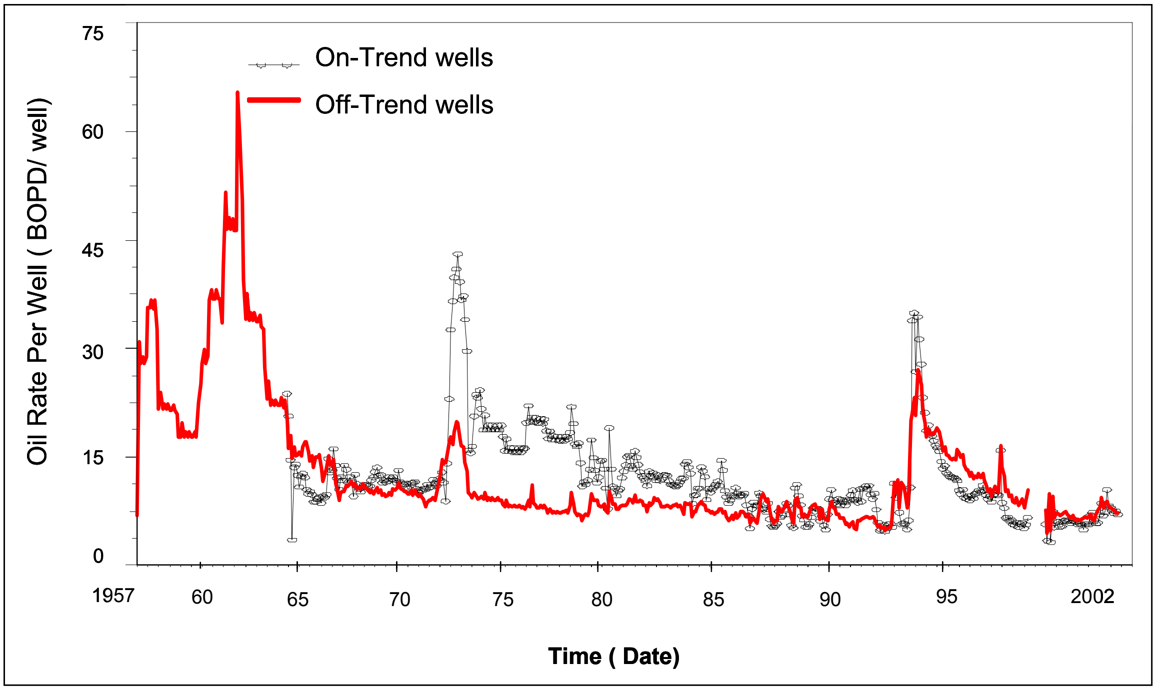

Fig. 17 -Oil Rate per Well for On-trend and Off-trend Wells.

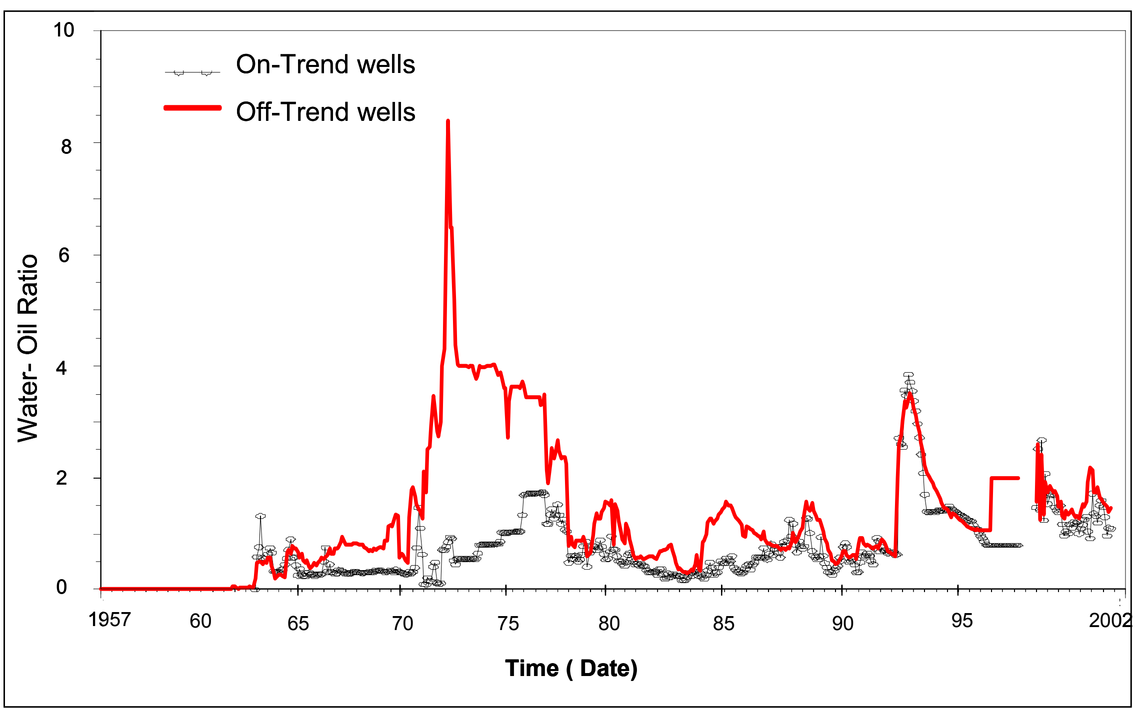

Fig. 18 -Average Water-Oil ratio for On-trend and Off-trend wells.

Drilling Programs

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 (drilling periods) for specific purposes. This is very important to evaluate the individual performance of the different programs and select the best practices and operations utilized for each group as well as evaluating the impact of them on the recovery. **Fig.19,** shows the different drilling programs used by the operator to develop the unit.

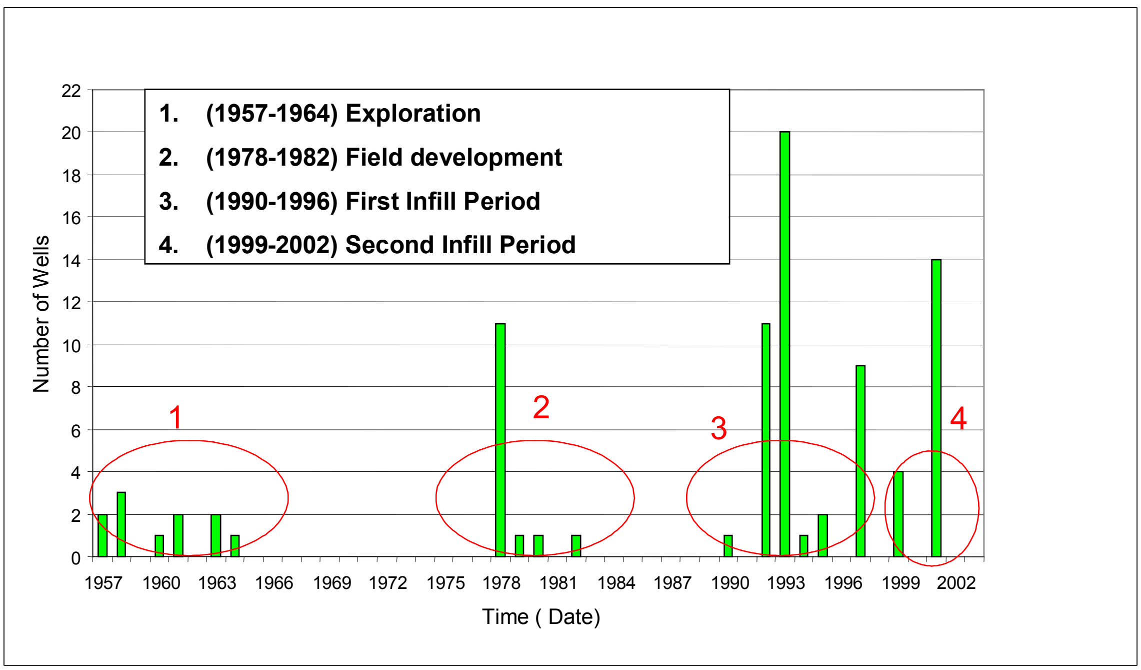

Fig. 19 -Different Drilling Campaigns for Development of Germania Spraberry Unit.

Drilling Program 1957-1964

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. 20** shows the location of the wells drilled from 1957 to 1964. Of this group of 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. 21** and **Table 2.**

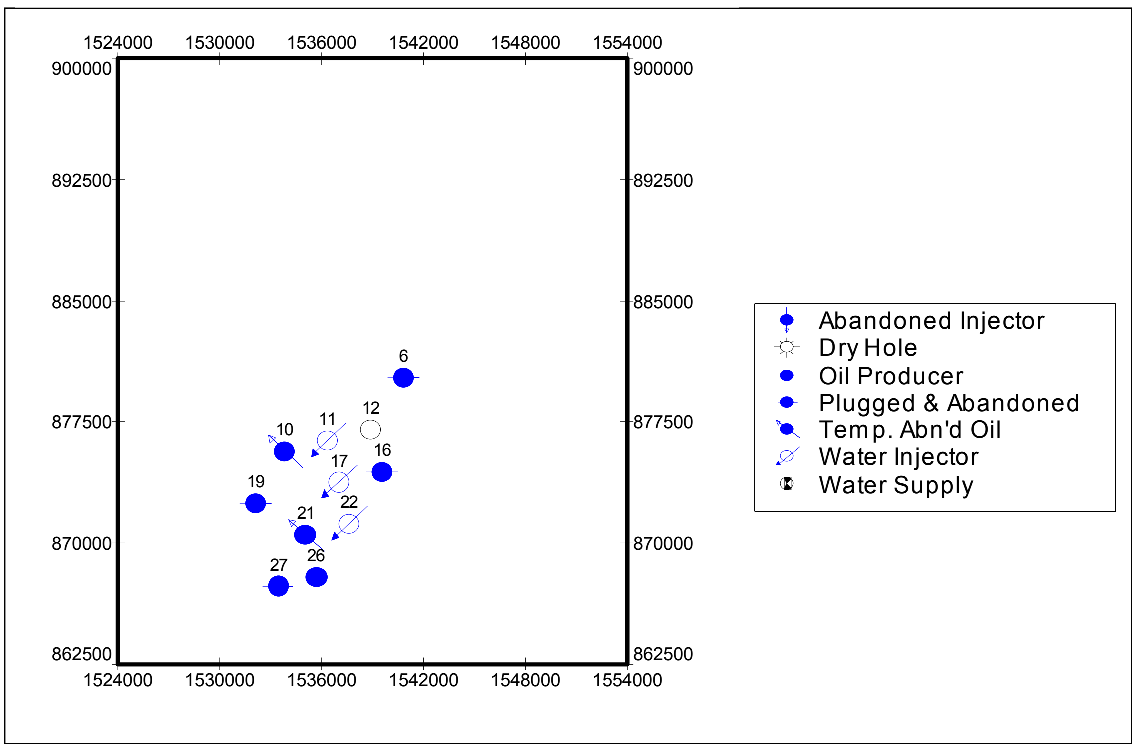

Fig. 20 -Base Map Showing the Location of Wells Drilled from 1957 to 1964.

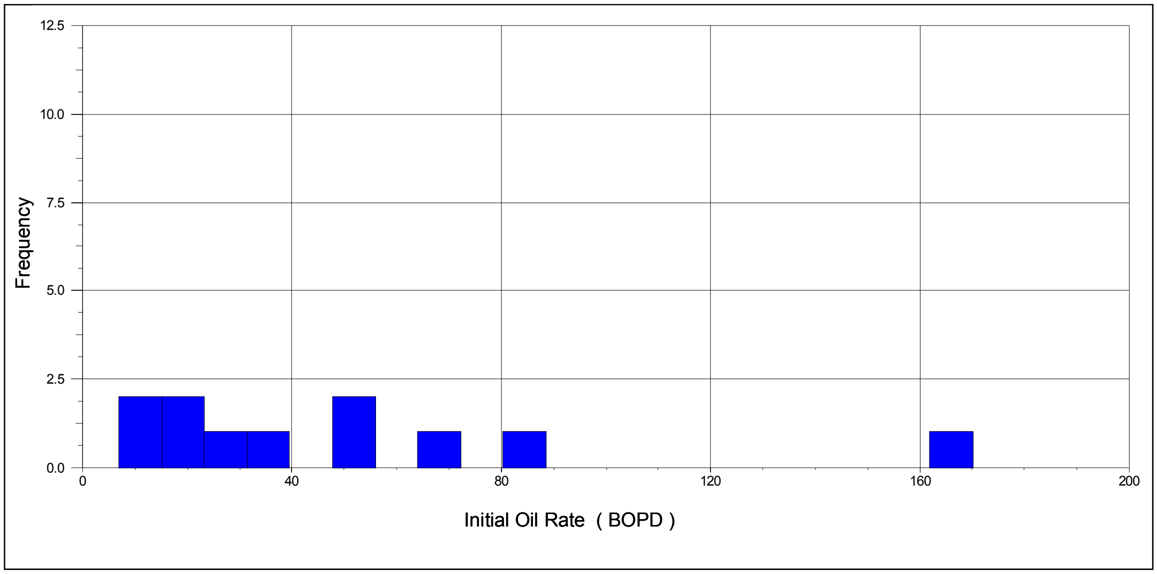

Fig. 21 -Histogram of Initial Oil Rate for Wells Drilled from 1957 to 1964.

Table 1-Statistical Analysis for Wells Drilled from 1957 to 1964.

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

Drilling Program 1978-1982

A total of 14 wells were drilled during the second drilling program (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. 22** shows the location of the wells drilled from 1978 to 1982. Of this group of 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. 23** and **Table 3.**

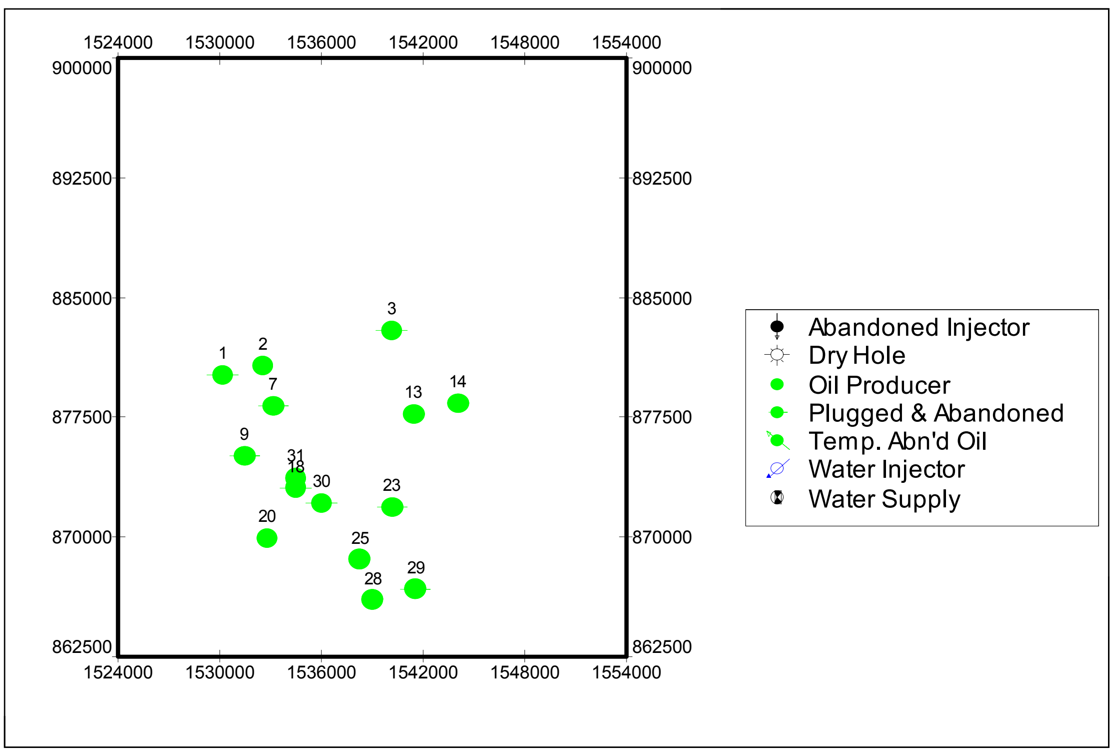

Fig. 22 -Base Map showing the Location of Wells Drilled from 1978 to 1982.

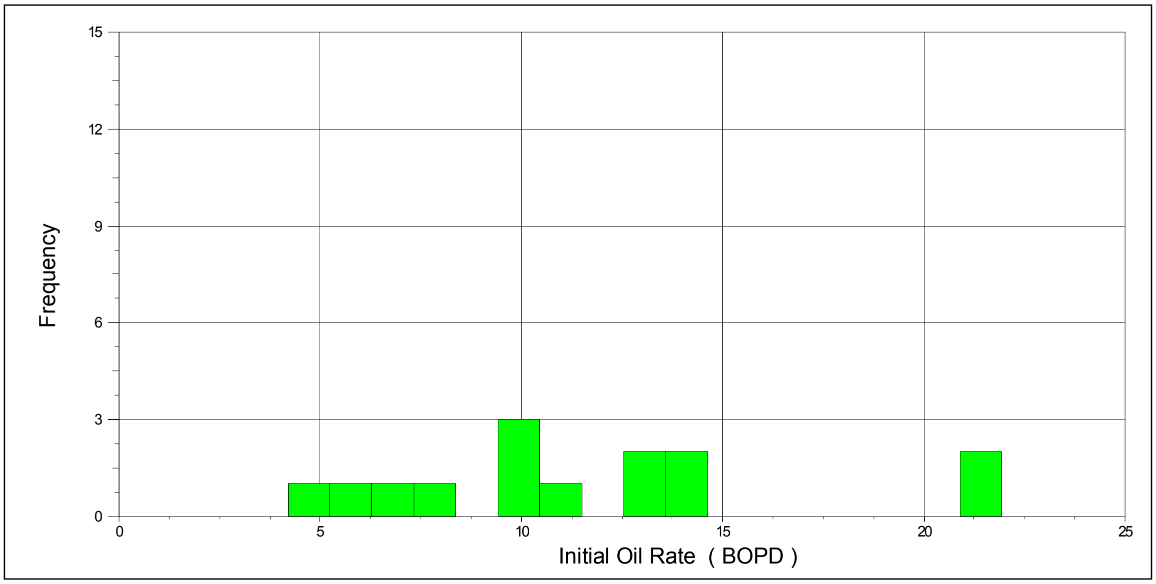

Fig. 23 -Histogram of Initial Oil Rate for Wells Drilled from 1978 to 1982.

Table 2- 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

Drilling Program 1990-1996

A total of 44 wells were drilled during this infill-drilling program (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. **Fig. 24** shows the location of the wells drilled from 1990 to 1996. Of this group of 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 cut (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. 25** and **Table 4.**

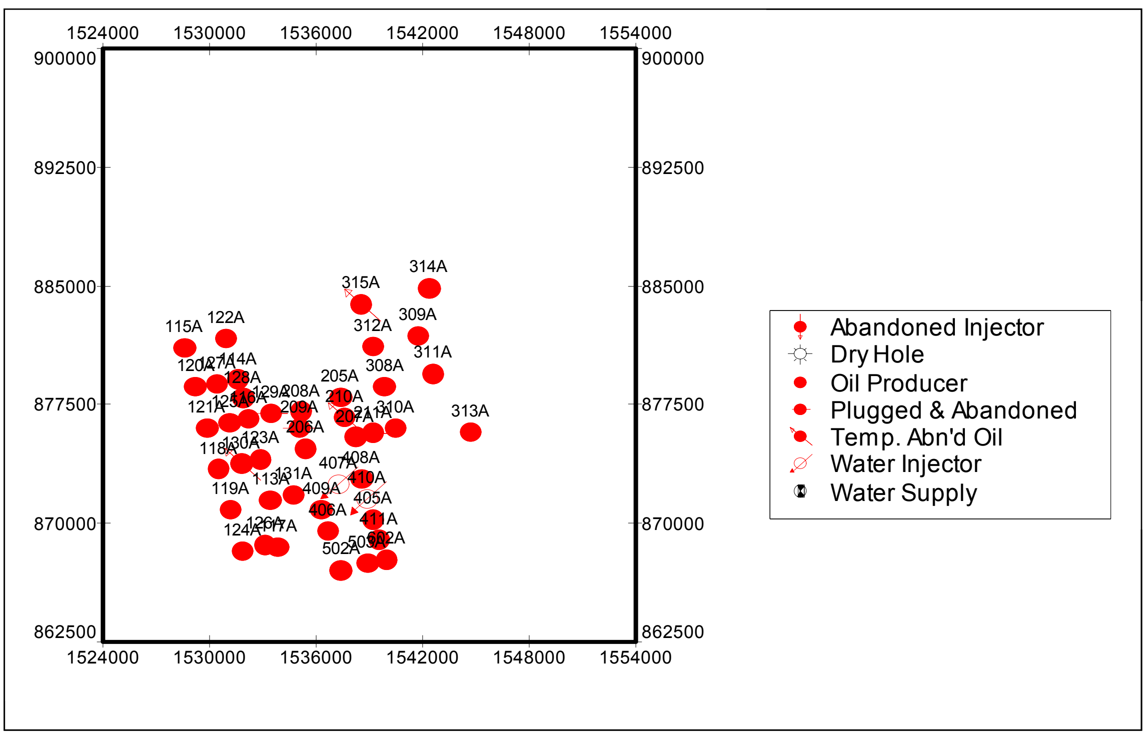

Fig. 24 -Base Map Showing the Location of Wells Drilled from 1990 to 1996.

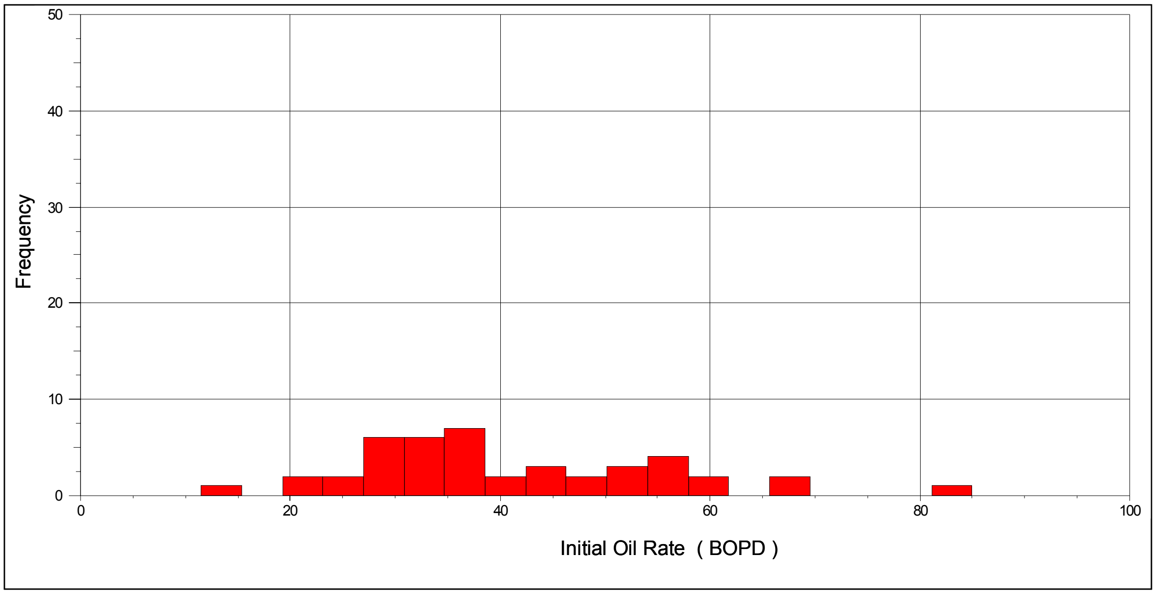

Fig. 25 -Histogram of Initial Oil Rate for Wells Drilled from 1990 to 1996.

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

Statistical Analysis
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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

Drilling Program 1999-2002

A total of 18 wells were drilled during this infill-drilling program (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 program began 42 years after the initiation of the waterflooding process). **Fig. 26,** 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. 27** and **Table 5.**

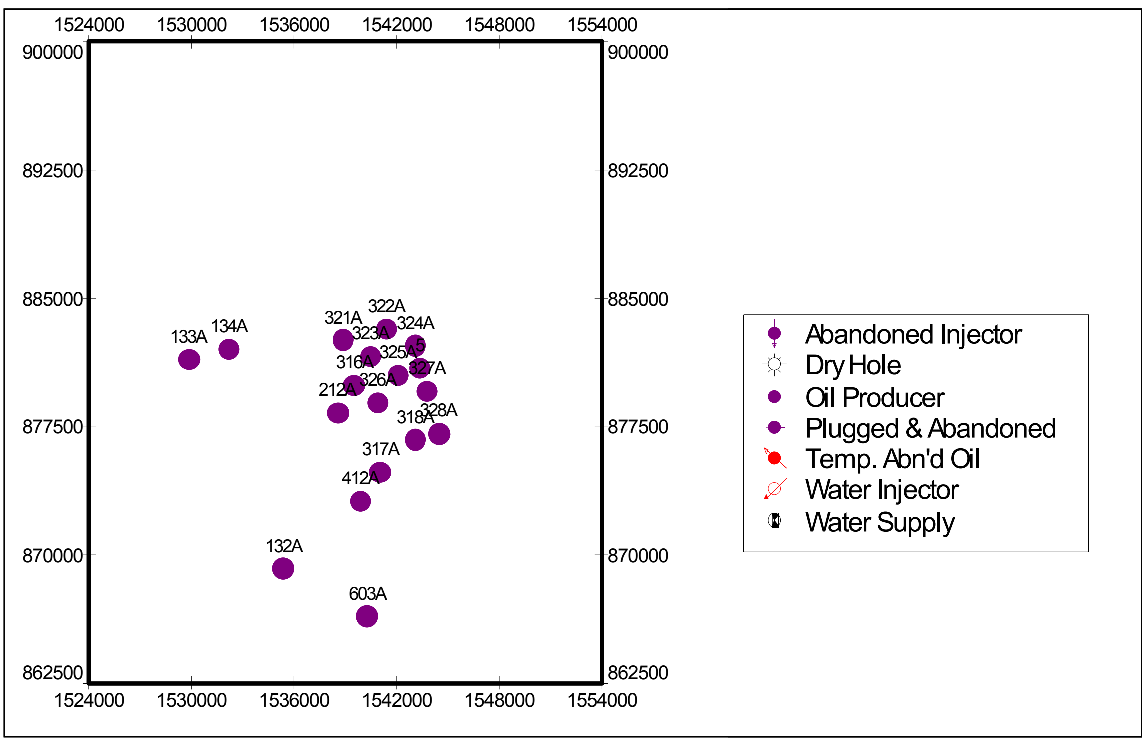

Fig. 26 -Base Map Showing the Location of Wells Drilled from 1999 to 2002.

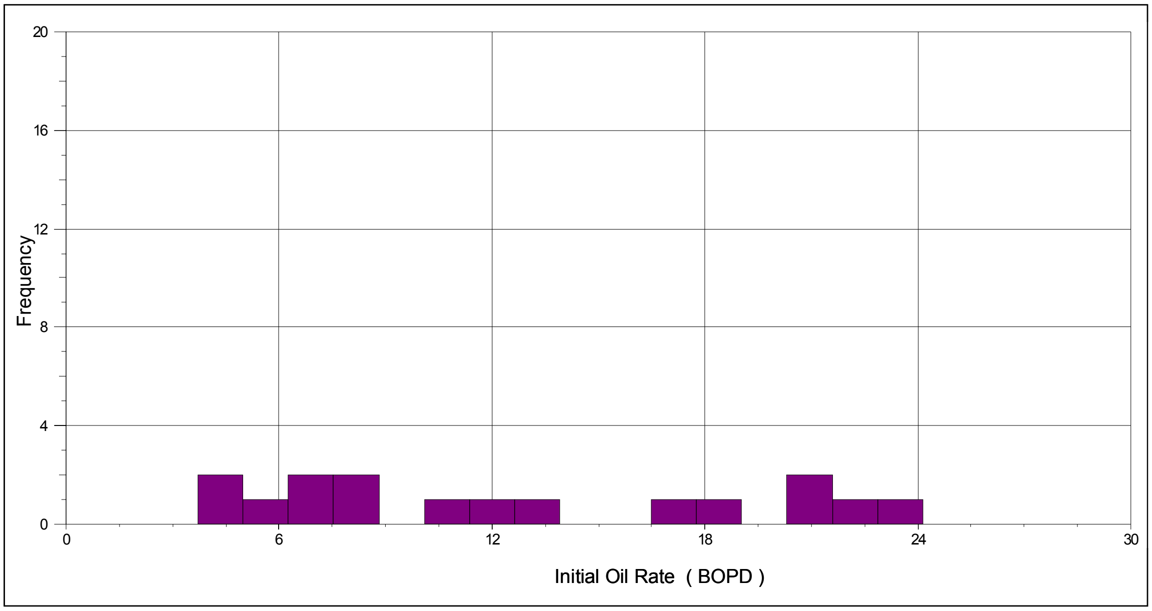

Fig. 27 -Histogram of Initial Oil Rate for Wells Drilled from 1999 to 2002.

Table 4- Statistical Analysis for Wells Drilled from 1999 to 2002.

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Statistical Analysis
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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
```

Comparative Analysis for Drilling Programs

According to **Fig. 28,** the second drilling program (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. 29, shows that all wells belonging to the four different programs, exhibit about the same decline rate**.** In this plot, we can also observe that the program that exhibit the highest average initial oil rate per well is the group 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 program, when the water saturation and the cumulative water injected were lower than the existing in the reservoir when the third and four programs took place. However, after 6,000 days in production the oil rate of this group of wells (program 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 program (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. 29.** 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. 30, 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 group of wells tended to reach the same value of water-oil ratio, averaging a current value of 2.

Historically; wells drilled during the third program (1990 to 1996), and the fourth program (1999 to 2002) have an initial oil rate higher than the remaining two programs.

This is because in the third and fourth programs, the wells accessed an area previously unflooded by the wells in the first and second programs.

Fig. 31; shows the cumulative oil production reached by the wells of the four different drilling programs. The wells drilled in the first programs exhibit the highest oil cumulative (1.4 million barrels) because they have been in production through the entire life of production of the unit.

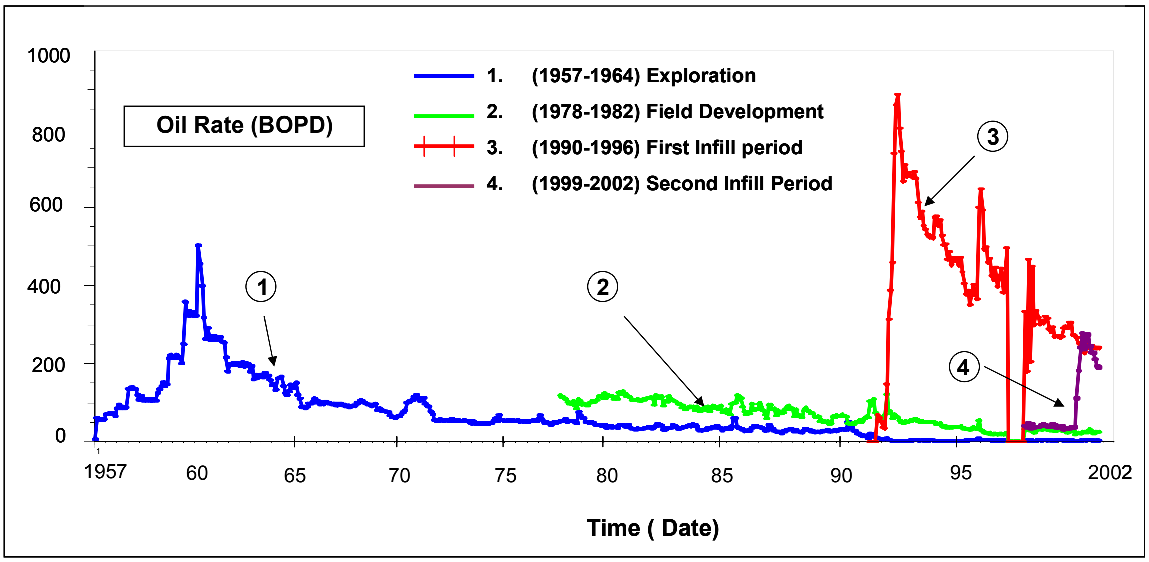

Fig. 28 - Initial Oil Rate for Wells Drilled from 1999 to 2002.

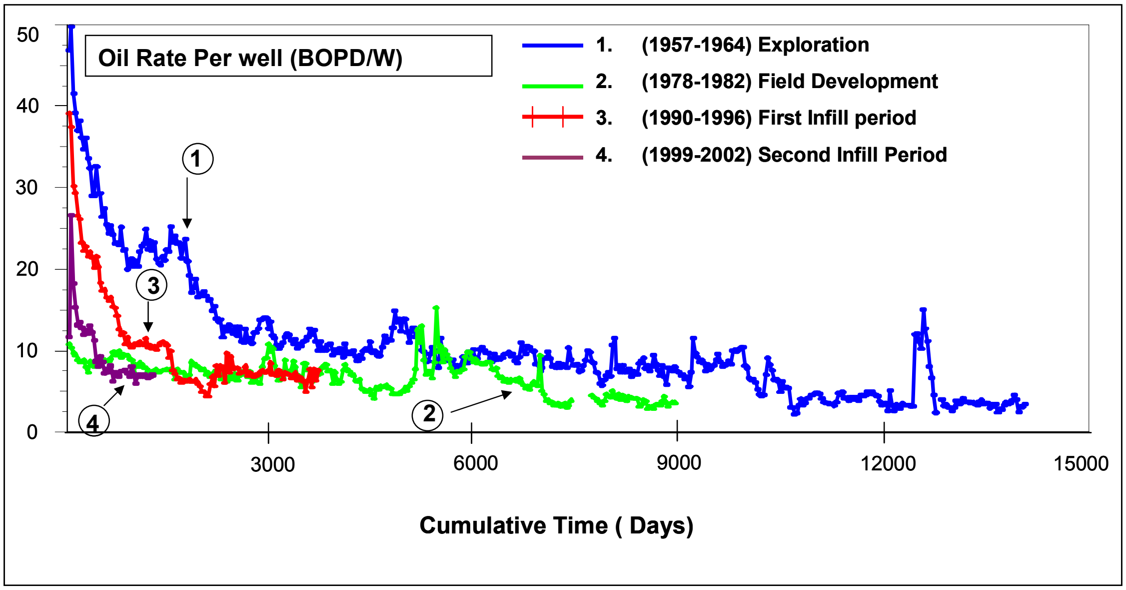

Fig. 29-Historical Oil Rate per Well for Different Drilling Programs During the Development of Germania Spraberry Unit.

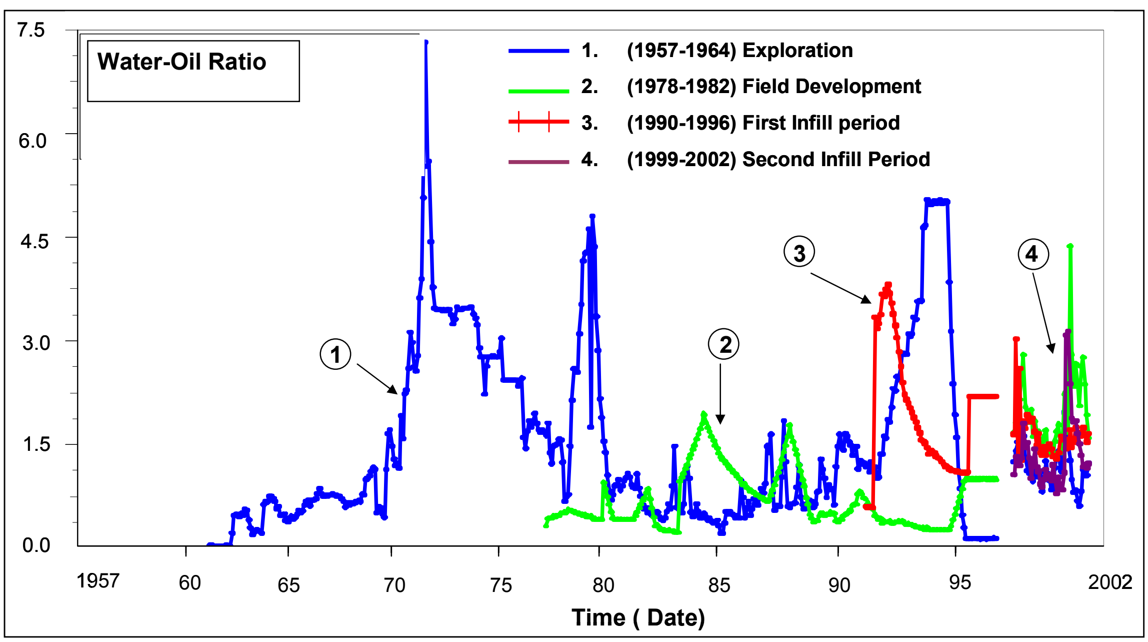

Fig. 30 -Historical Water-Oil Ratio for Different Drilling Programs During the Development of Germania Spraberry Unit.

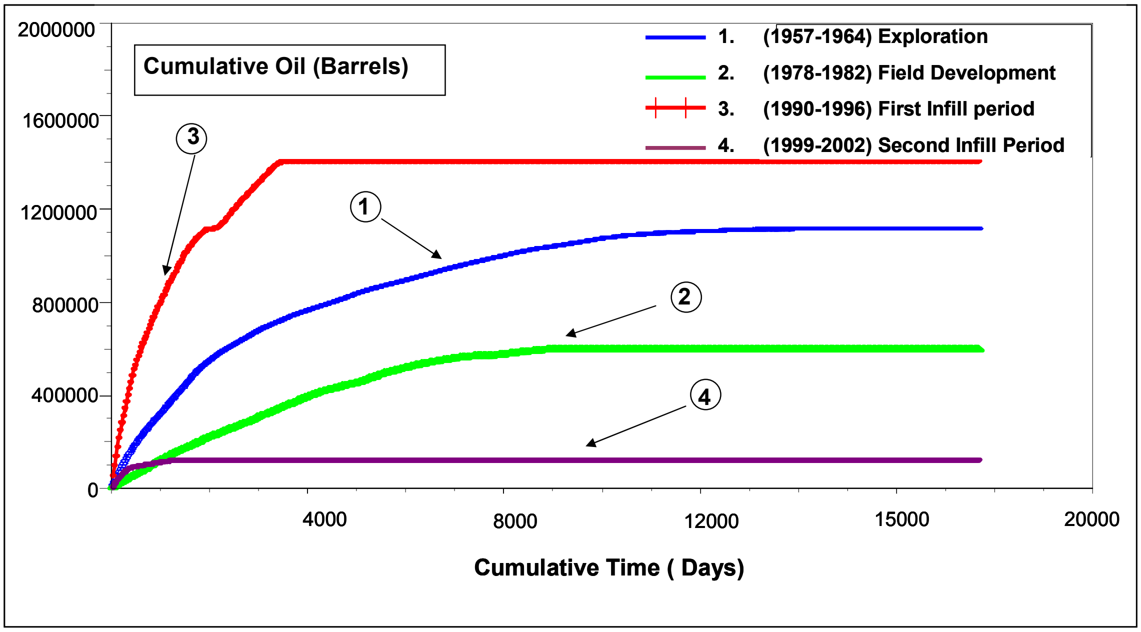

Fig. 31 -Cumulative Oil Production for Different Drilling Programs During the Development of Germania Spraberry Unit.

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. 32** shows the location and definition of the six different areas in Germania Spraberry Unit.

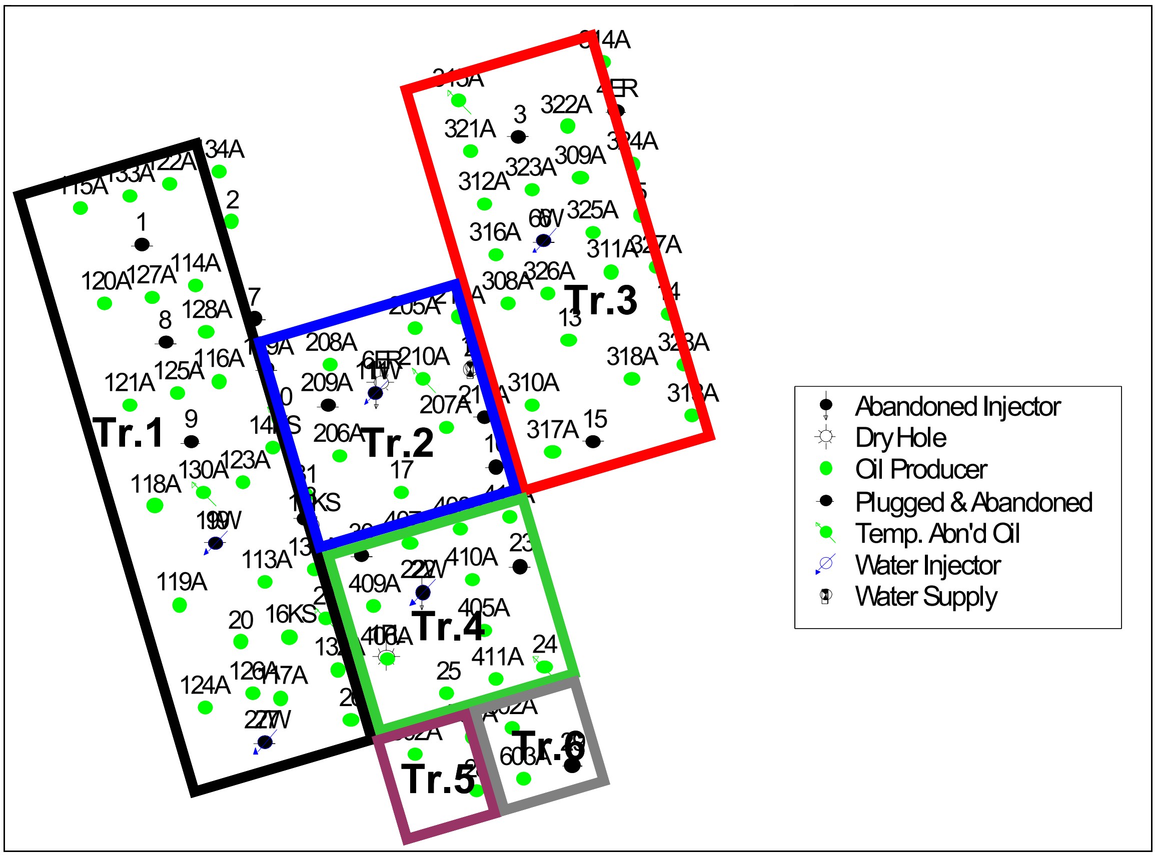

Fig. 32 -Location of Individual Tracts in Germania Spraberry Unit.

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. 33,** 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. 34,** 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 44.25 percent of the total produced by the entire unit.

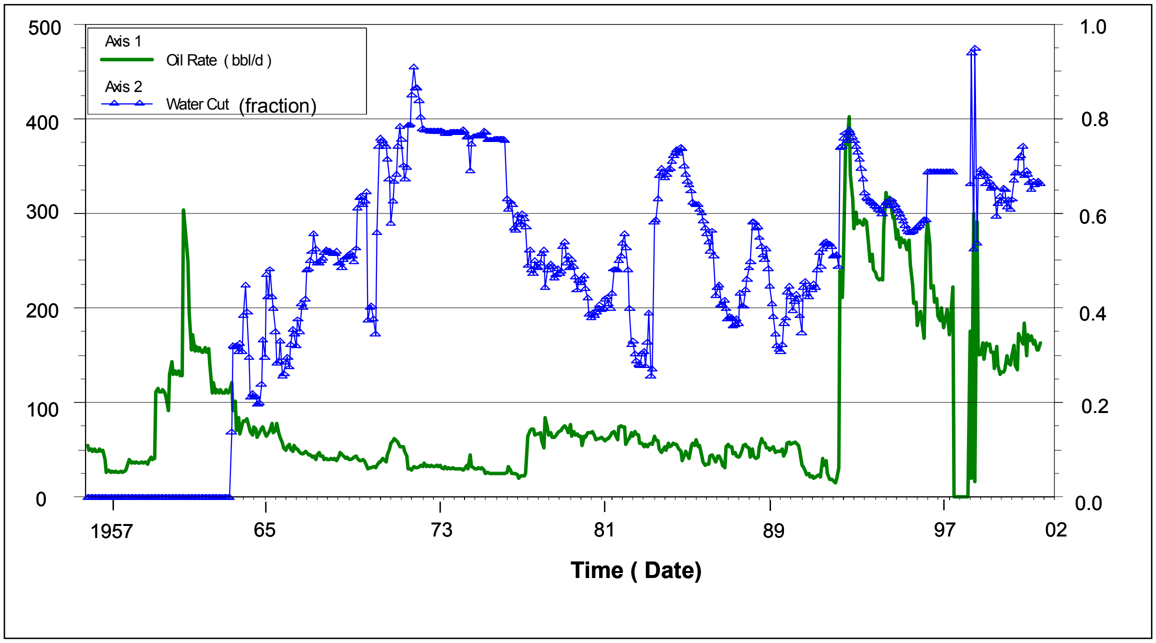

Fig. 33 -Oil Rate and Water Cut for Tract 1. (Germania Spraberry Unit.)

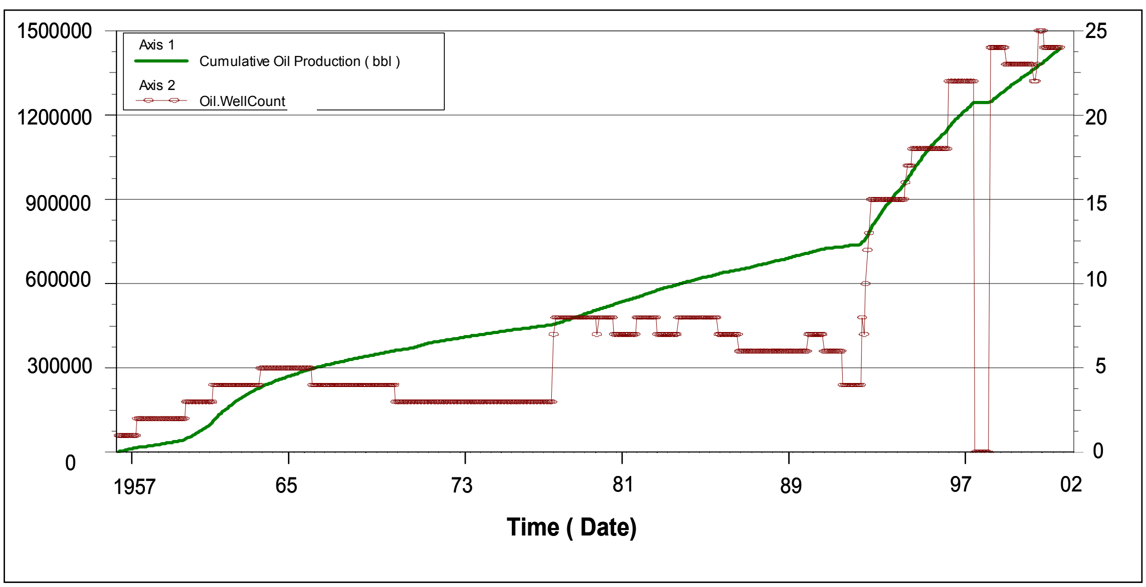

Fig. 34 -Cumulative Oil Production and Active Wells for Tract 1. (Germania Spraberry Unit).

Tract 2

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. 35,** 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. 36,** 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.

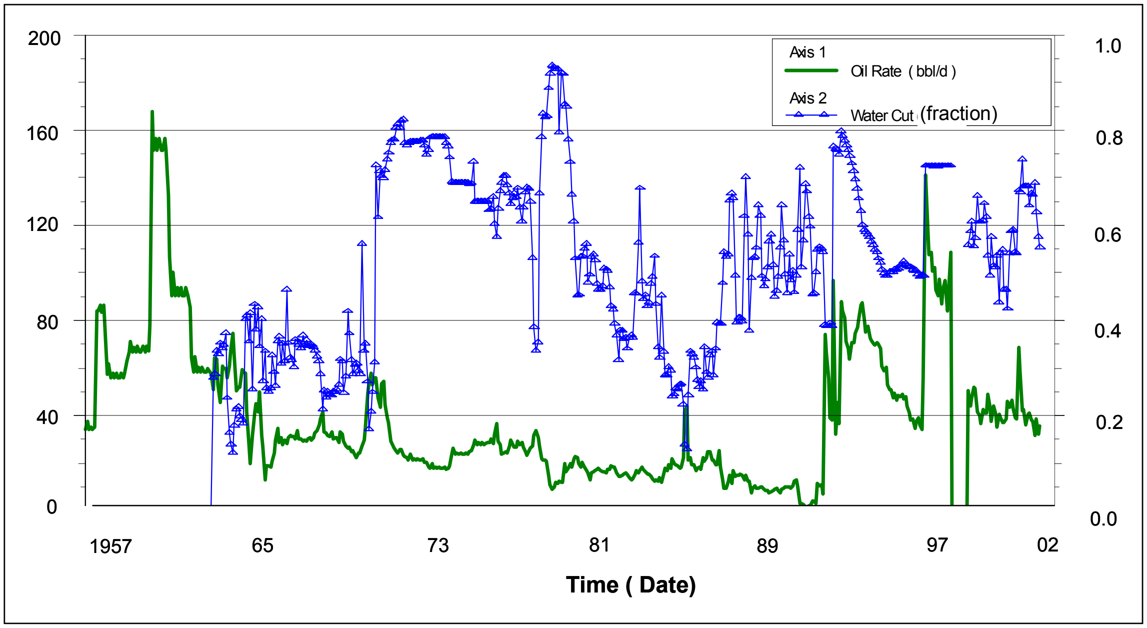

Fig. 35 -Oil Rate and Water Cut for Tract 2. (Germania Spraberry Unit.)

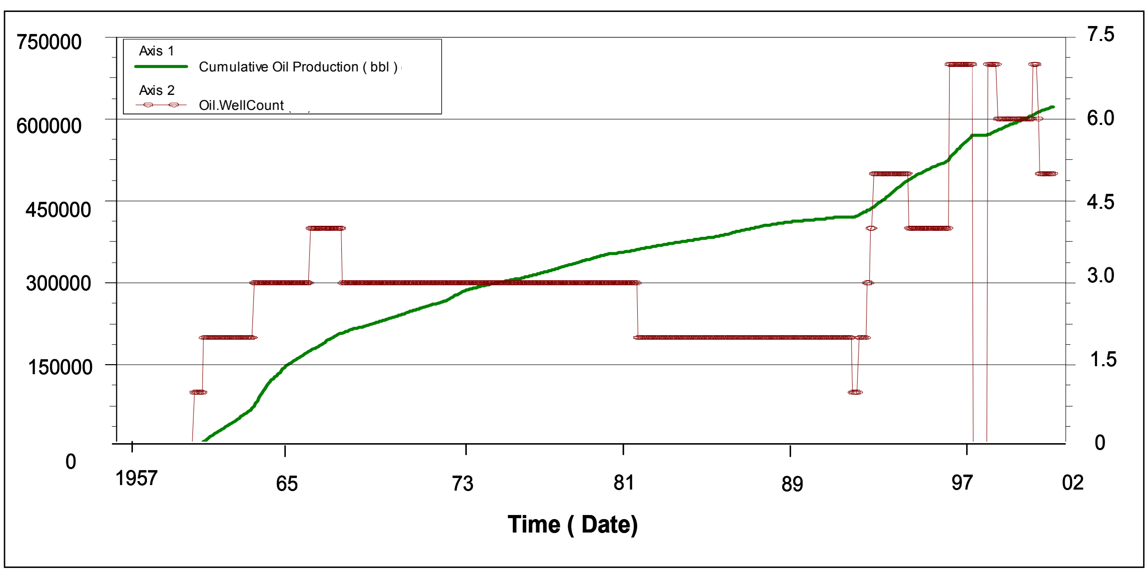

Fig. 36 -Cumulative Oil Production and Active Wlls for Tract 2. (Germania Spraberry Unit).

Tract 3

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. 37,** 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. 38,** 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)

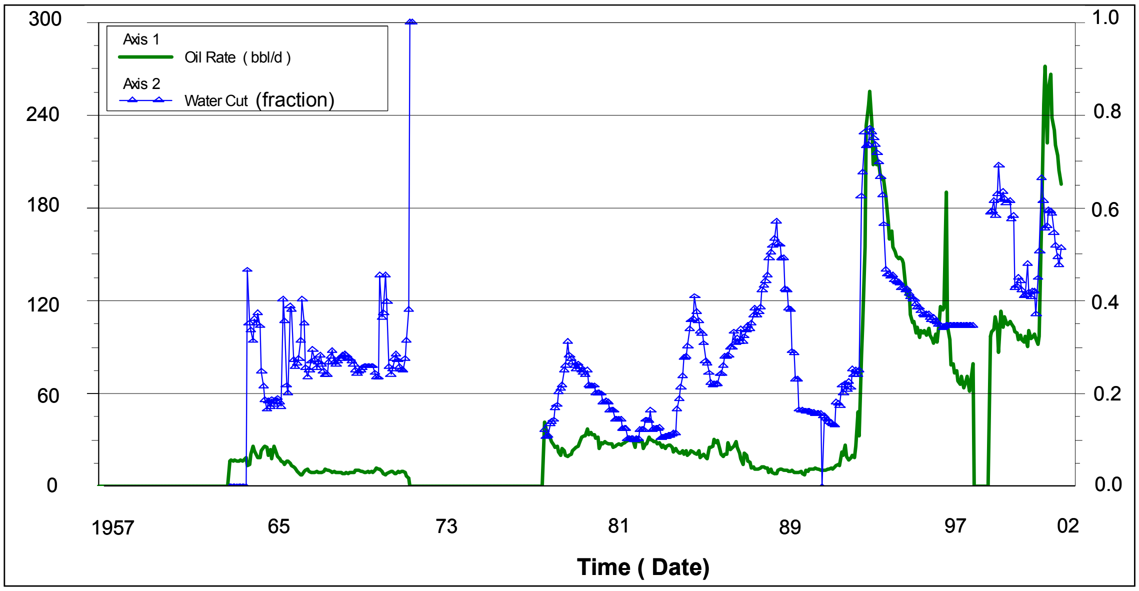

Fig. 37 -Oil Rate and Water Cut for Tract 3. (Germania Spraberry Unit.)

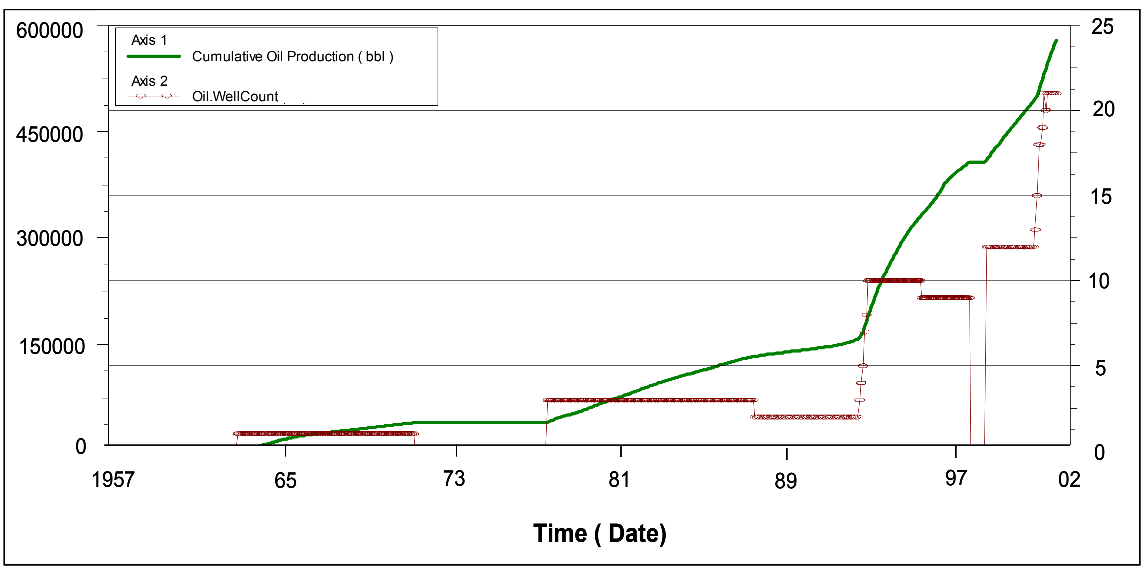

Fig. 38 -Cumulative Oil Production and Active Wells for Tract 3. (Germania Spraberry Unit).

Tract 4

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. 39,** 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. 40,** 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 13.75 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).

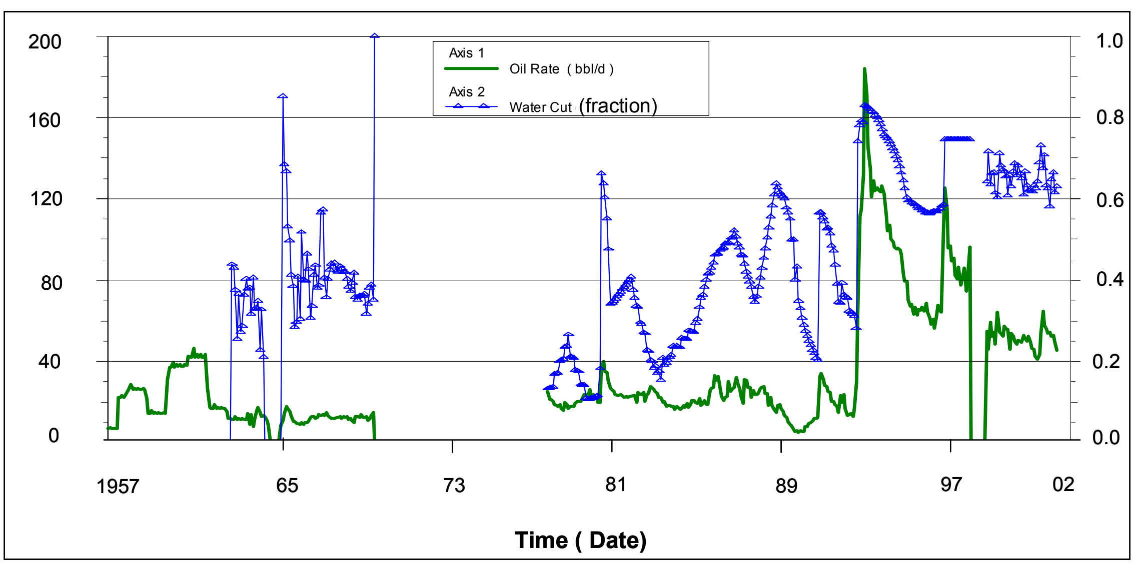

Fig. 39 -Oil Rate and Water Cut for Tract 4. (Germania Spraberry Unit.)

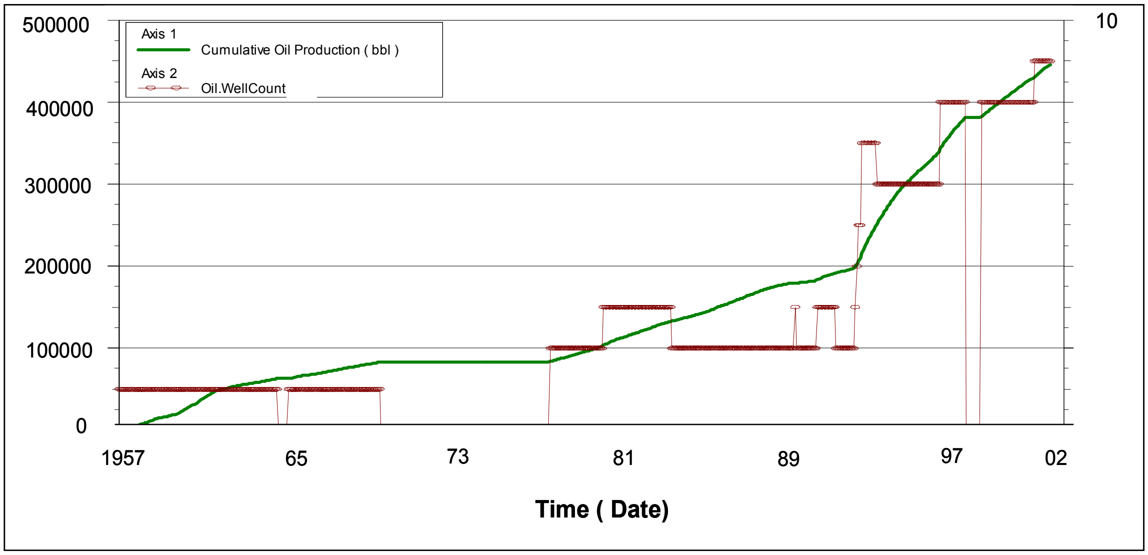

Fig. 40 -Cumulative Oil Production and Active Wells for Tract 4. (Germania Spraberry Unit).

Tract 5

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.41,** 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.42,** 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).

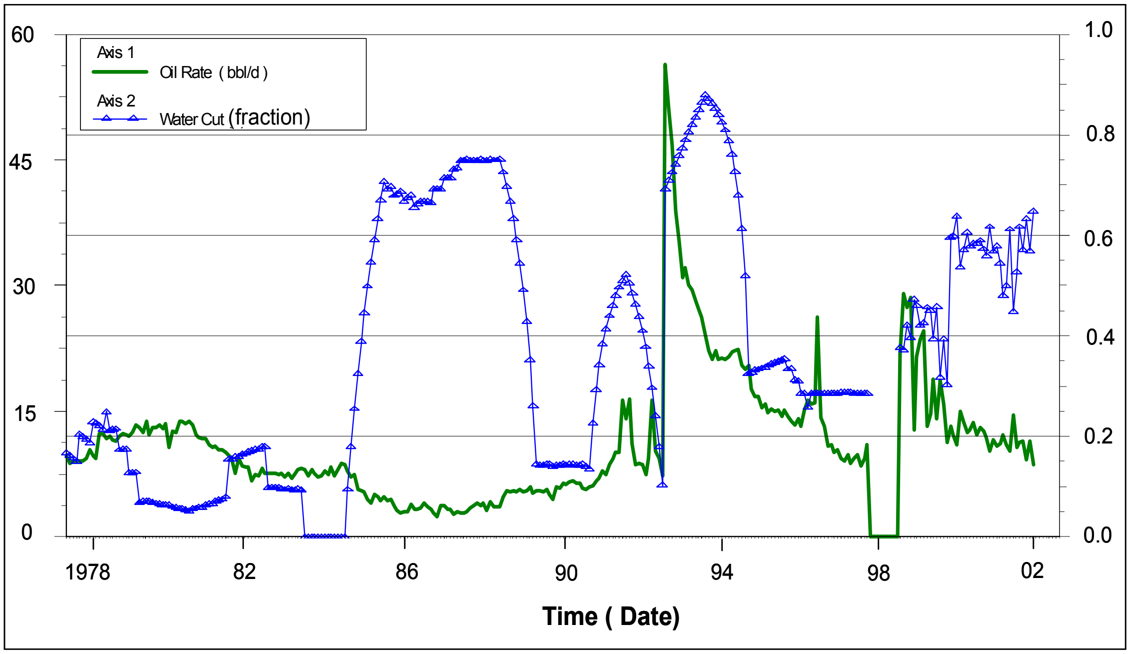

Fig. 41 -Oil Rate and Water Cut for Tract 5. (Germania Spraberry Unit.)

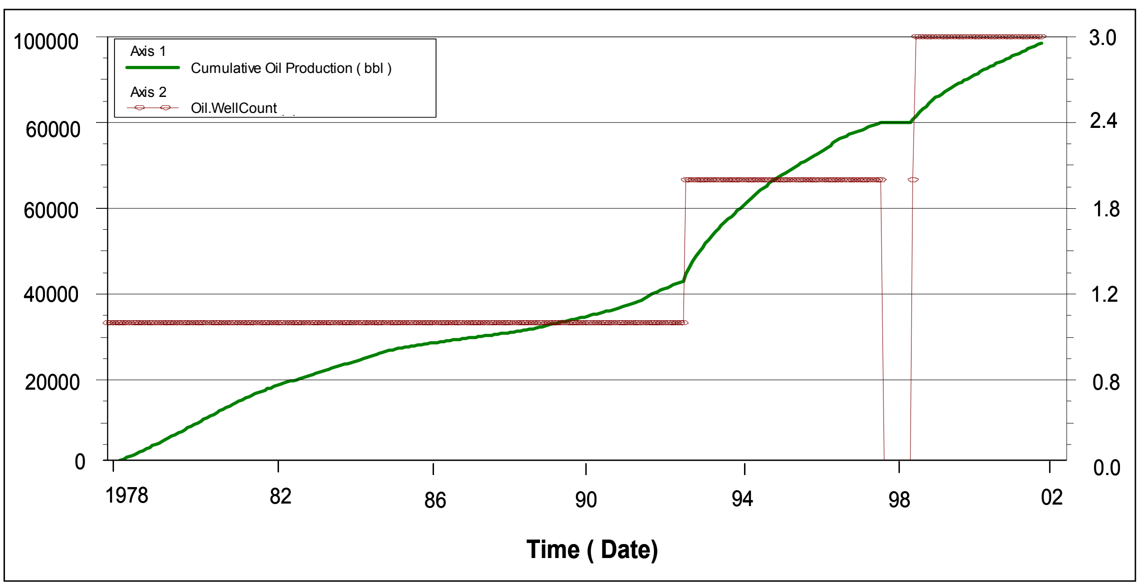

Fig. 42 -Cumulative Oil Production and Active Wells for Tract 5. (Germania Spraberry Unit).

Tract 6

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.43,** 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.44,** 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 which experienced communication problems, 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.

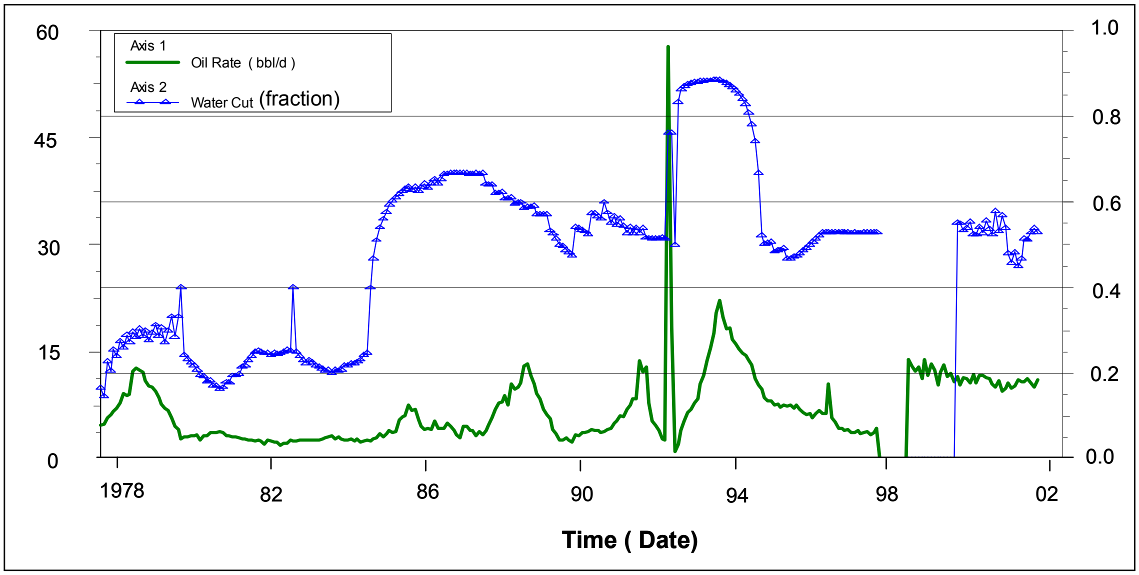

Fig. 43 -Oil Rate and Water Cut for Tract 6. (Germania Spraberry Unit.)

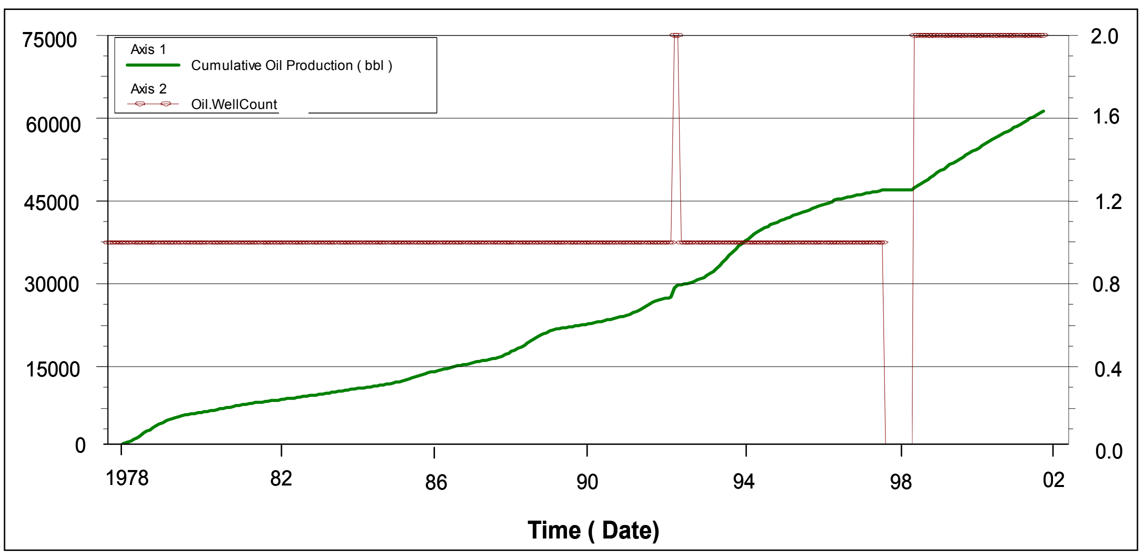

Fig. 44 -Cumulative Oil Production and Active Wells for Tract 6. (Germania Spraberry Unit).

Comparative Analysis for Tracts

Fig.45, 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.46,** 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.45,** 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 4.6 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 improve the performance in Germania Spraberry Unit.

As shown in **Fig.47**, 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 24. Tracts 3, 4, 5, and 6 have shown an historical average water-oil ratio of 3, indicating a uniform drainage in all these tracts.

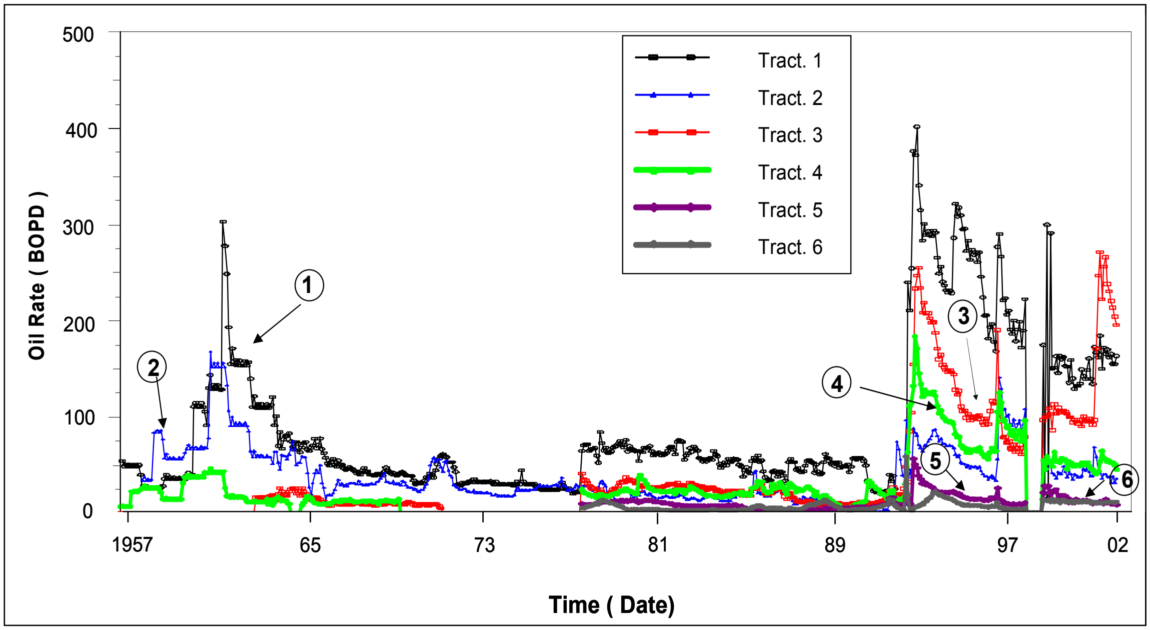

Fig. 45 -Historical Oil Rate for Different Tracts of Germania Spraberry Unit.

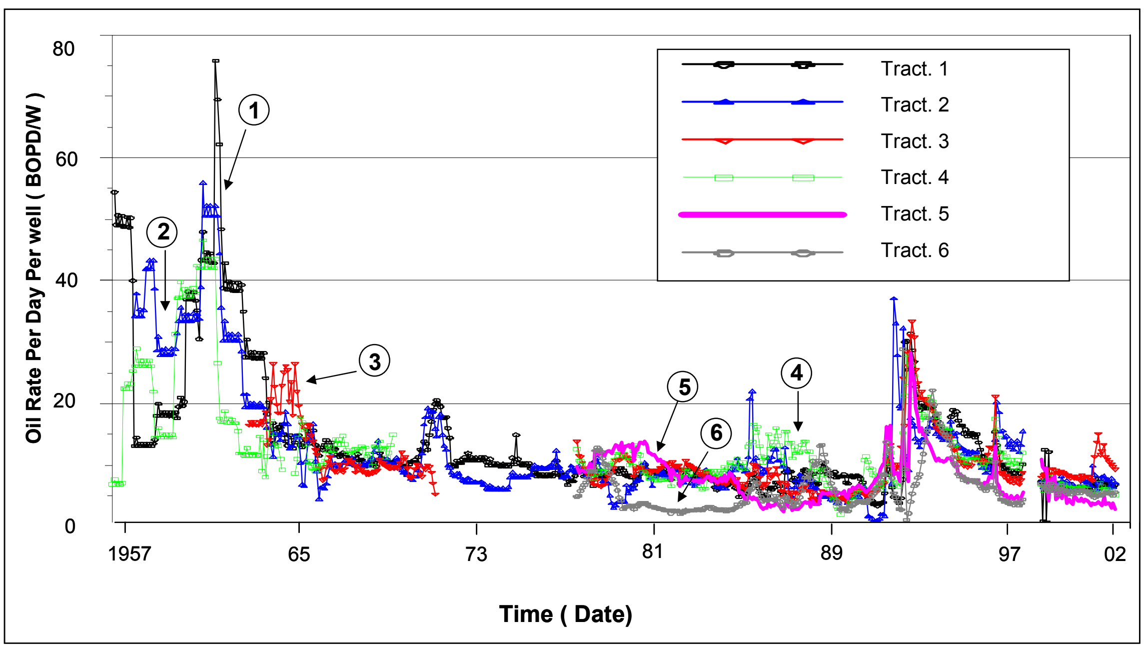

Fig. 46 -Historical Oil Rate per Well for Different Tracts of Germania Spraberry Unit.

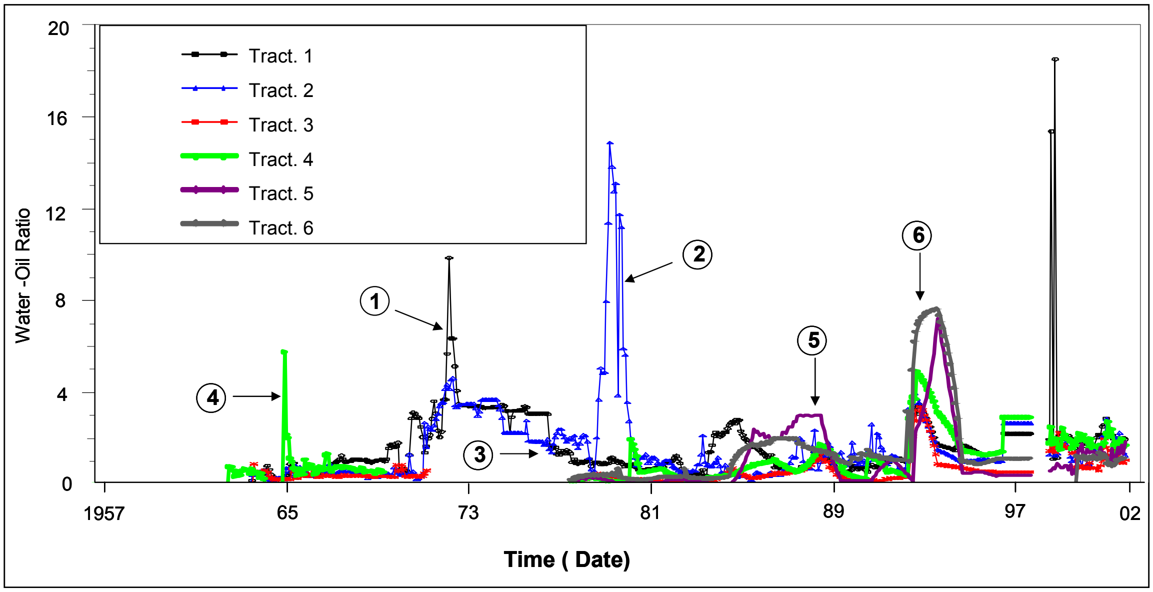

Fig. 47 -Historical Water-Oil Ratio for Different Tracts of Germania Spraberry Unit.

Table 5- 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	

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.

Water Control Diagnostic Plots

Based on numerical simulation studies on reservoir water coning and channeling, it was discovered 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[4]. These set of plot were generated by Chan in 1995 after conducting a series of water-control numerical simulation studies using a black oil simulator and are capable of representing or modeling the performance of flow under different drive mechanisms and waterflood schemes. The analysis of the different plots is done by inspecting the departure time of the WOR and the slope of the derivatives of WOR. 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) as a result of the exposition of the casings to the water (some casing have been in contact with corrosive water for more than 50 years) .

It is important to mention that this technique must only be used only as a screening criterion to differentiate among the different mechanisms responsible for excessive water production in Germania , and then combine the results with conventional plots, well completion, cement logs , well files , etc. before selecting candidates for water control treatments.

In general, there are three basic classifications of the problems. Water coning, multilayer channeling and near wellbore problems are the most noticeable among others. Very often, a near wellbore problem could suddenly occur during a normal displacement and production. **Figs. 48**, **49, 50, 51, 52, 53, 54,** and **55** 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.

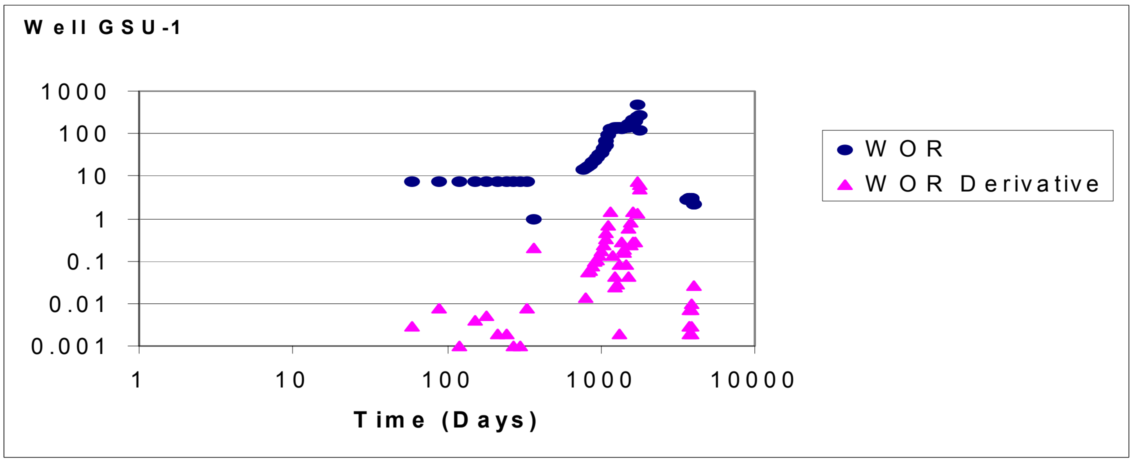

Fig. 48 -WOR and WOR Derivative for Well GSU-1: Experiencing Near Wellbore Water Channeling.

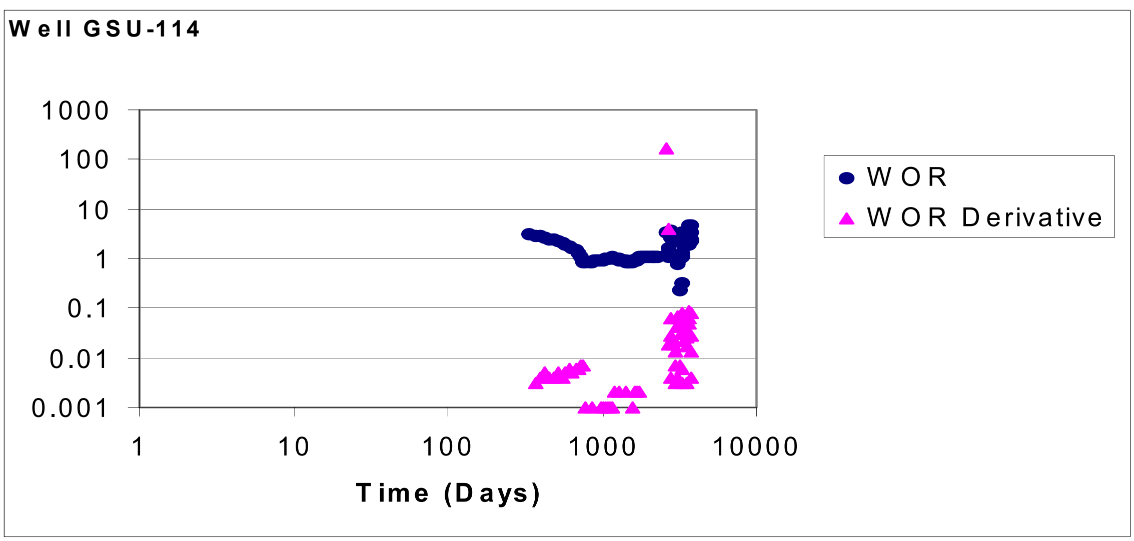

Fig. 49 -WOR and WOR Derivative for Well GSU-114: Experiencing Near Wellbore Water Channeling.

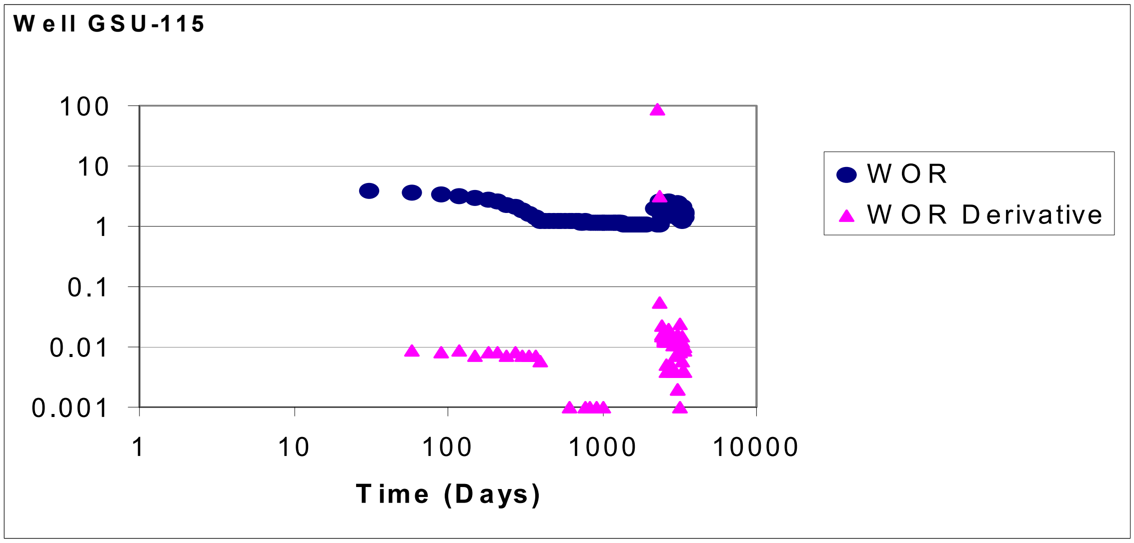

Fig. 50 -WOR and WOR Derivative for Well GSU-115: Experiencing Near Wellbore Water Channeling.

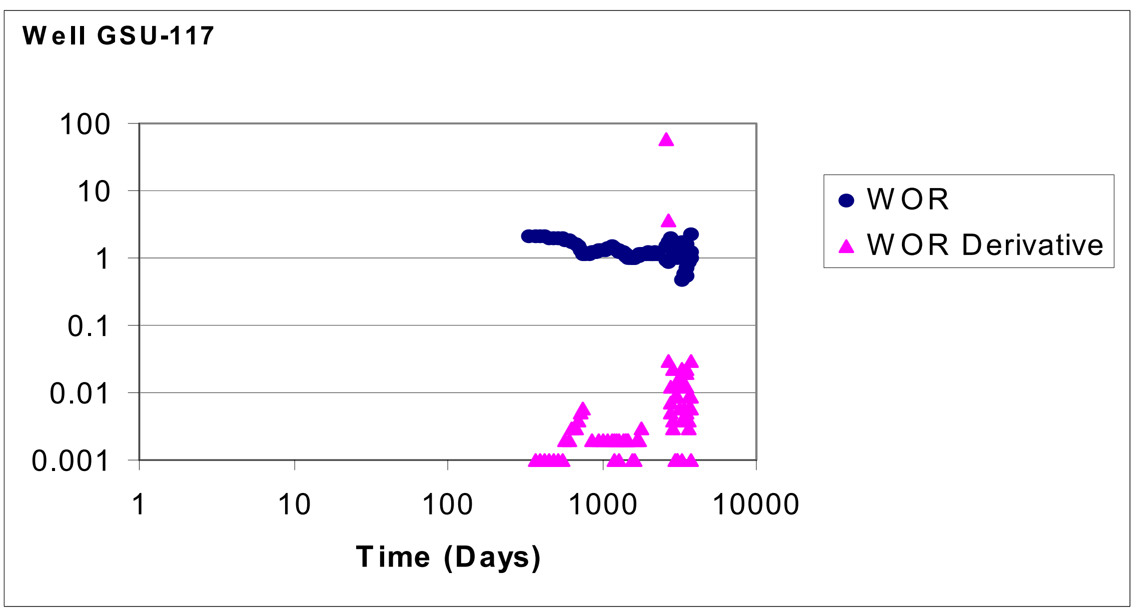

Fig. 51 -WOR and WOR Derivative for Well GSU-117: Experiencing Near Wellbore Water Channeling.

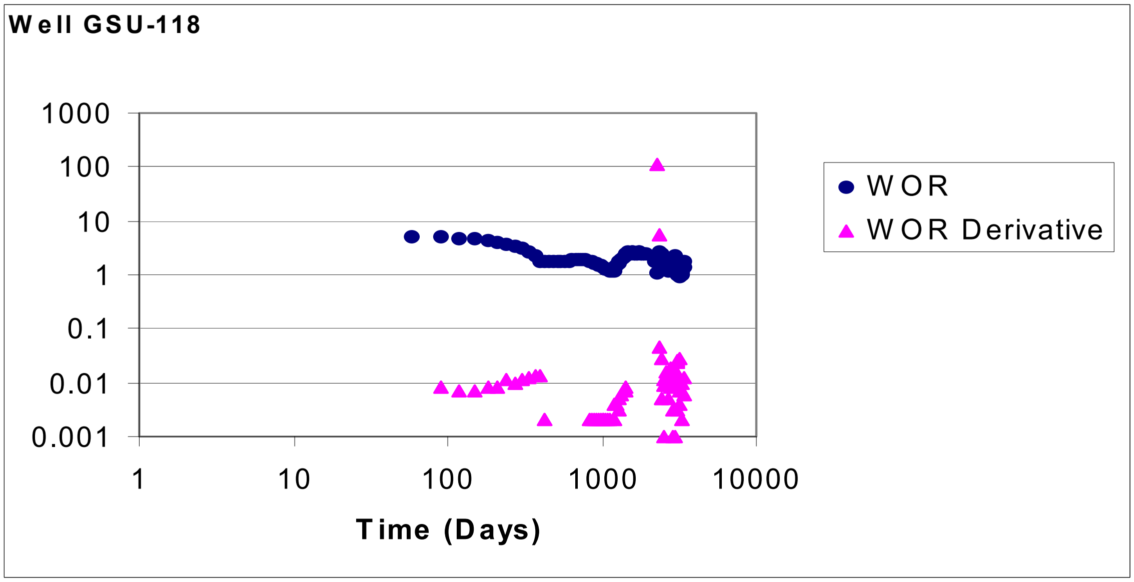

Fig. 52 -WOR and WOR Derivative for Well GSU-118: Experiencing Near Wellbore Water Channeling.

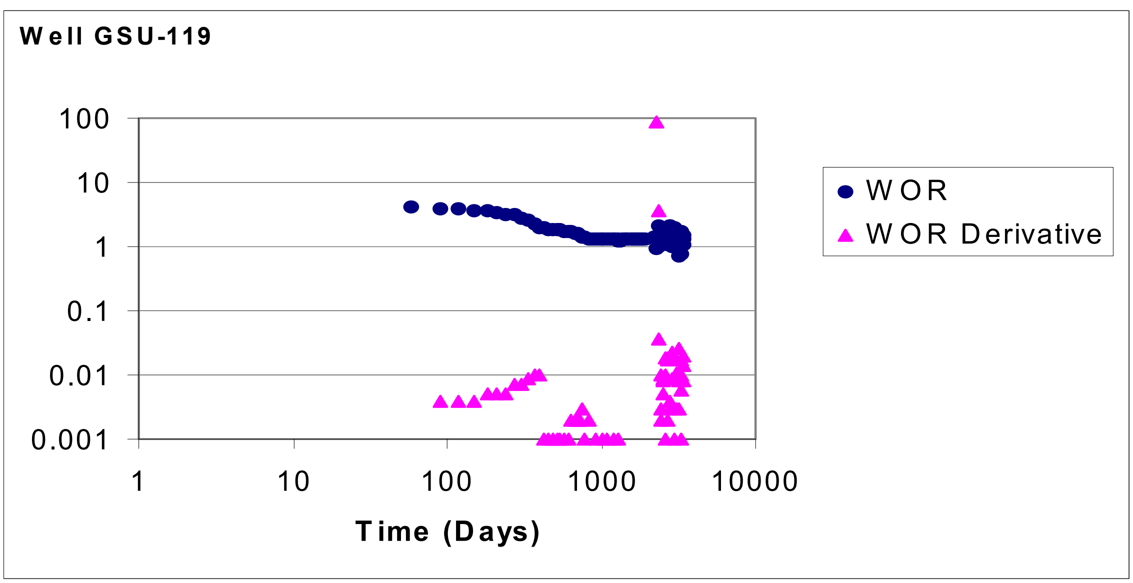

Fig. 53 -WOR and WOR Derivative for Well GSU-119: Experiencing Near Wellbore Water Channeling.

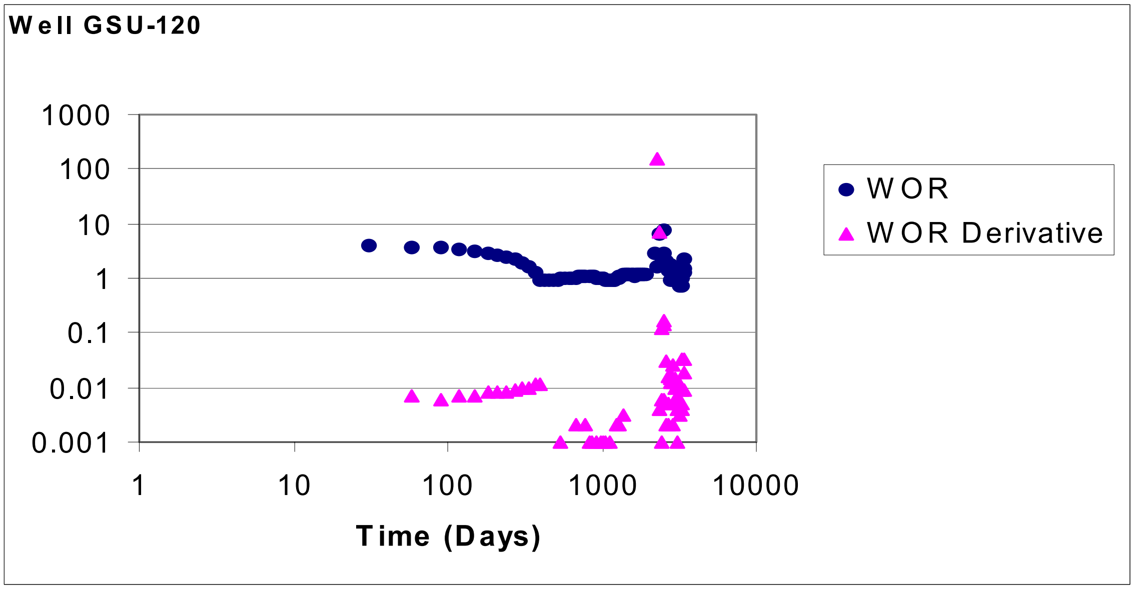

Fig. 54 -WOR and WOR Derivative for Well GSU-120: Experiencing Near Wellbore Water Channeling

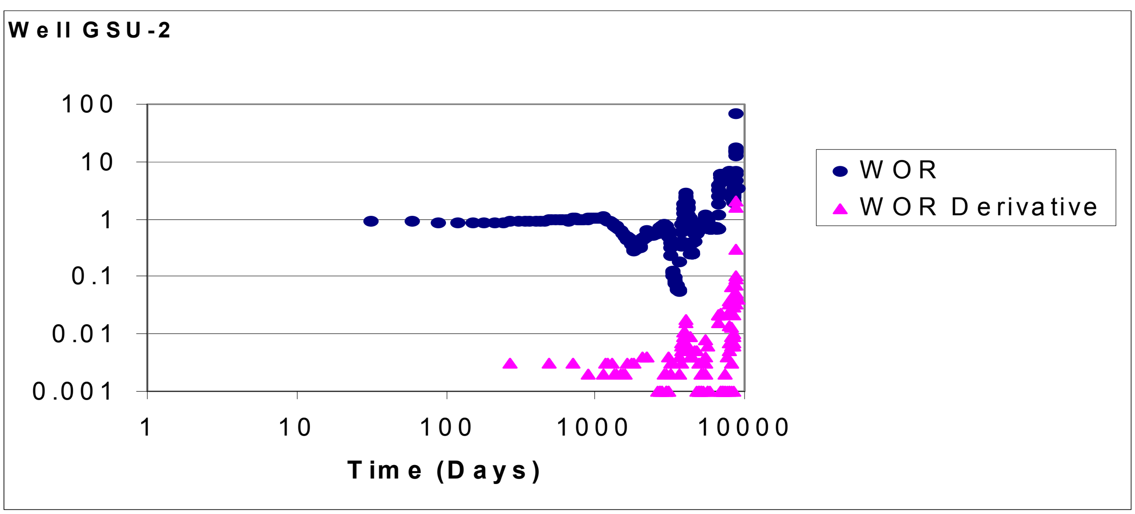

Fig. 55 -WOR and WOR Derivative for Well GSU-2: Experiencing Near Wellbore Water Channeling.

Figs. 56 and **57** 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.

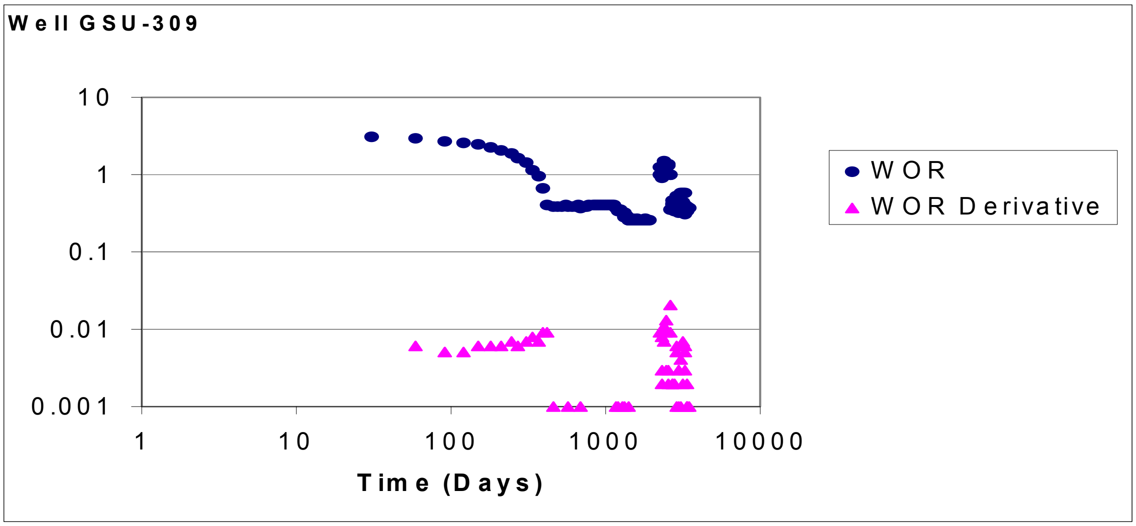

Fig. 56 -WOR and WOR Derivative for Well GSU-309: Experiencing Water Coning with Late Time Channeling.

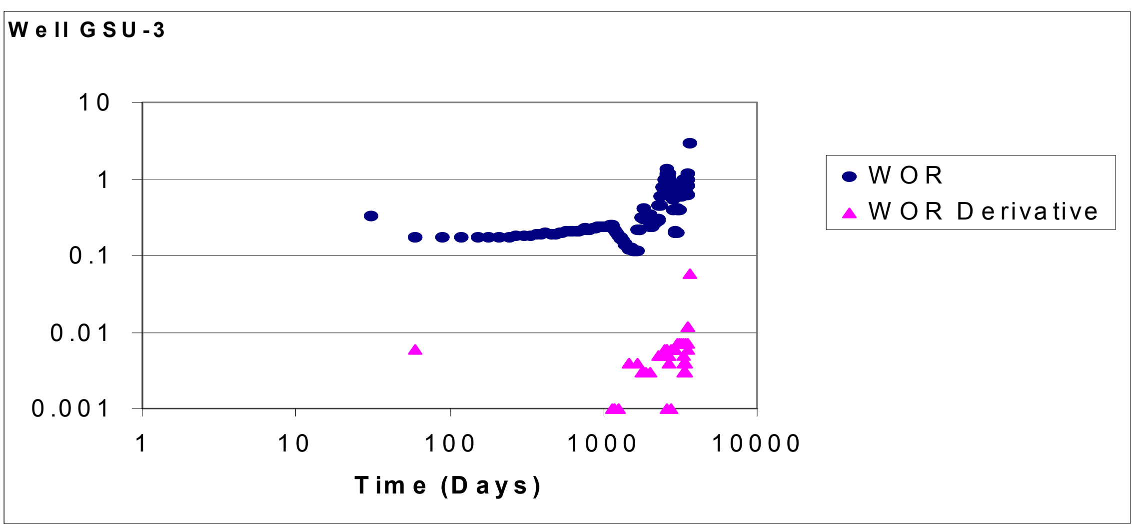

Fig. 57 -WOR and WOR Derivative for Well GSU-3: Experiencing Water Coning with Late Time Channeling.

Figs. 58, 59, 60, 61, 62, 63, and **64** 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.

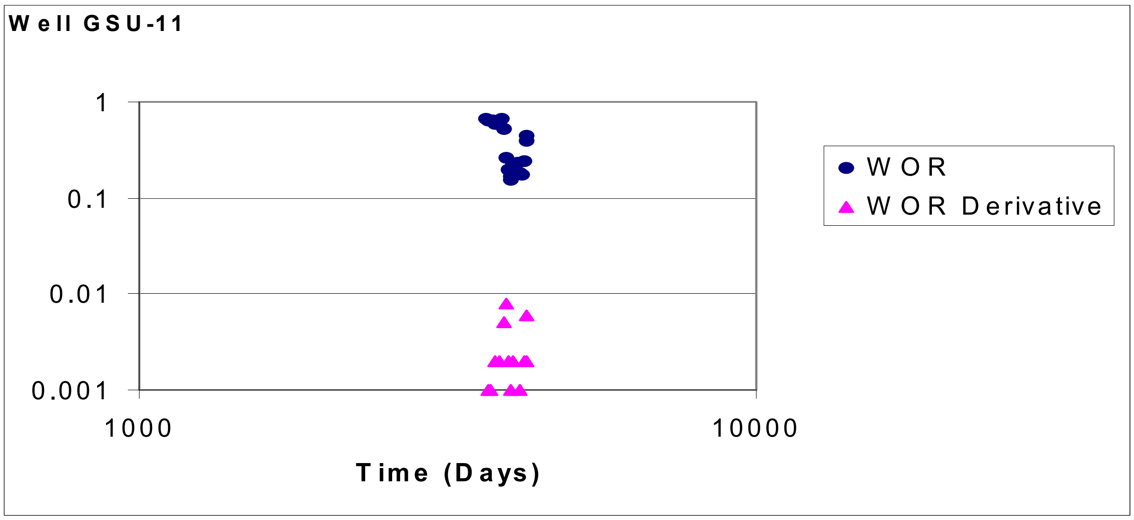

Fig. 58 -WOR and WOR Derivative for Well GSU-11: Experiencing Rapid Channeling.

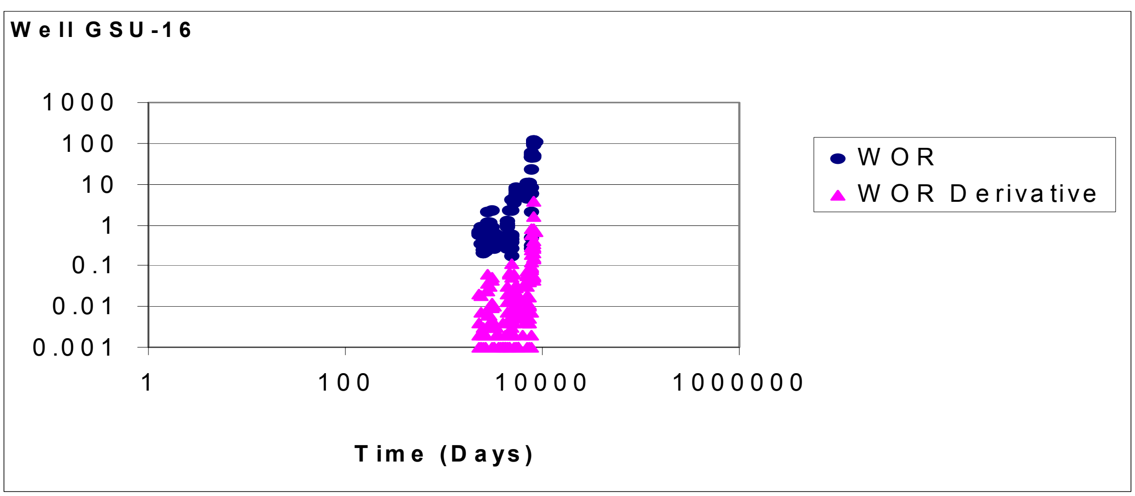

Fig. 59 -WOR and WOR Derivative for Well GSU-16: Experiencing Rapid Channeling.

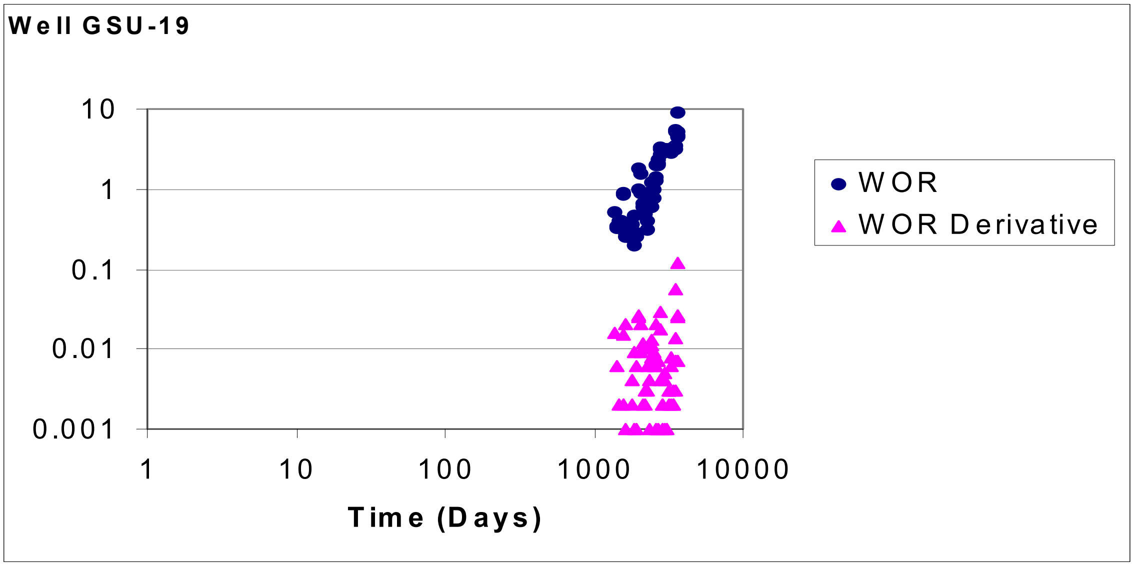

Fig. 60 -WOR and WOR Derivative for Well GSU-19: Experiencing Rapid Channeling.

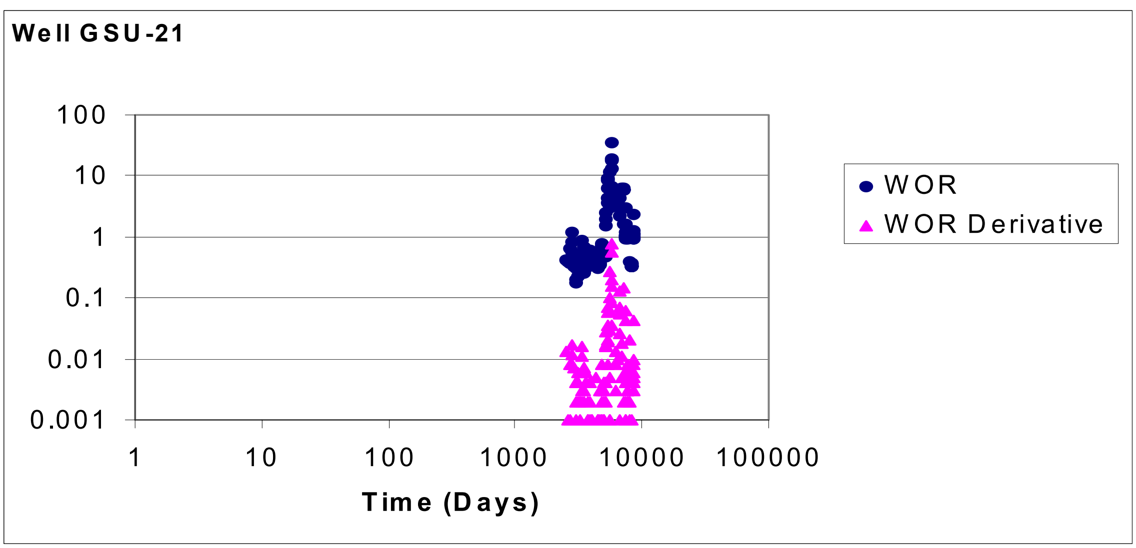

Fig. 61 -WOR and WOR Derivative for Well GSU-21: Experiencing Rapid Channeling.

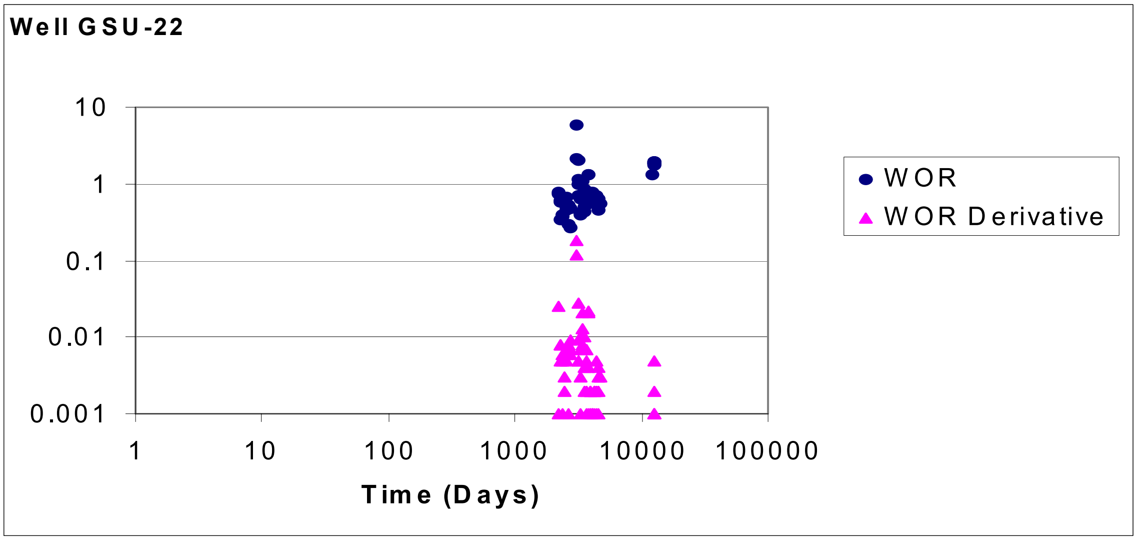

Fig. 62 -WOR and WOR Derivative for Well GSU-22: Experiencing Rapid Channeling

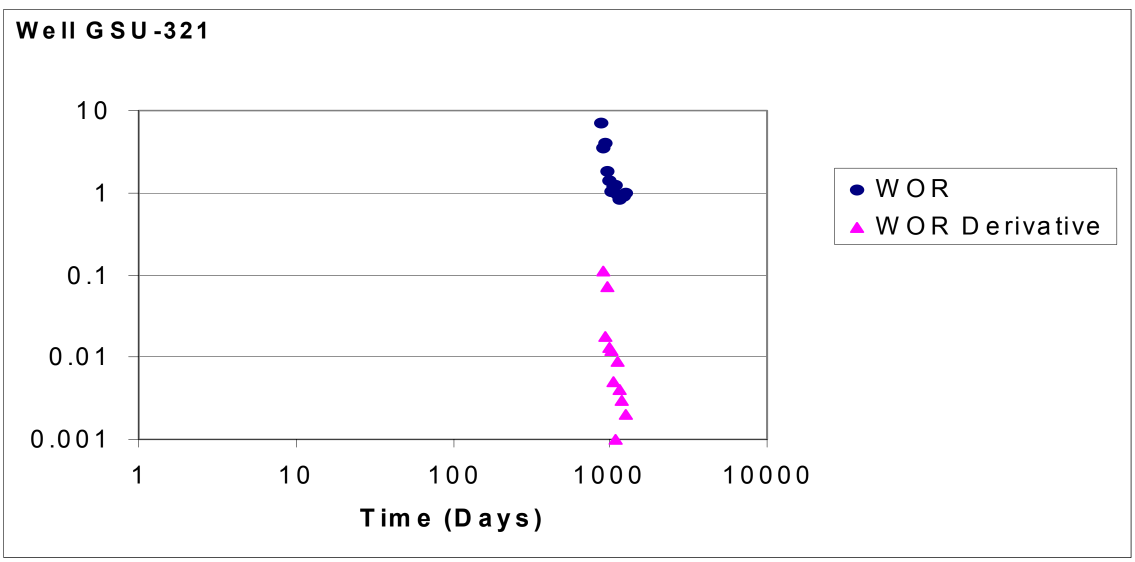

Fig. 63 -WOR and WOR Derivative for Well GSU-321: Experiencing Rapid Channeling.

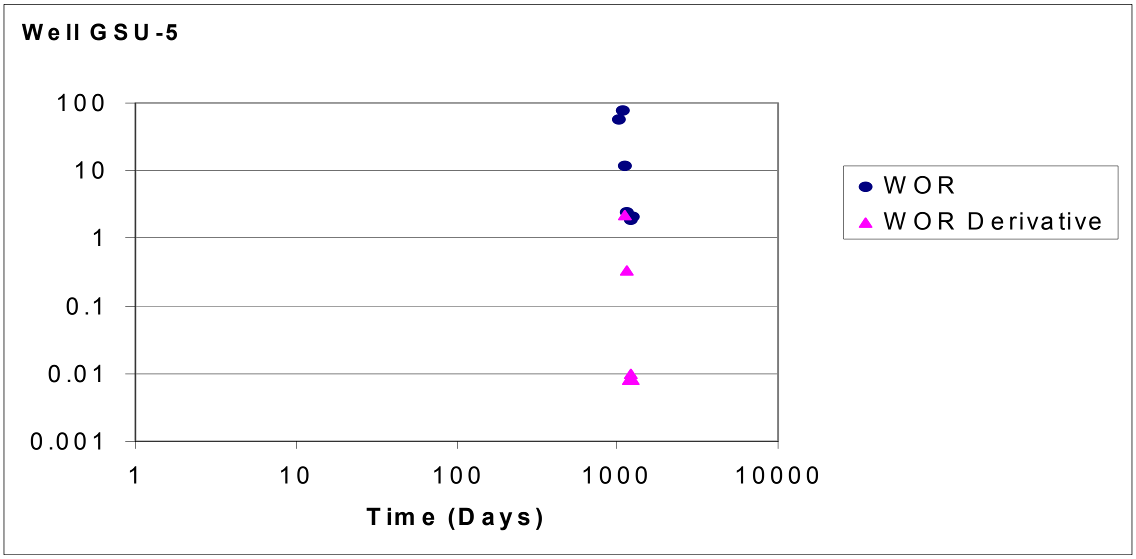

Fig. 64 -WOR and WOR Derivative for Well GSU-5: Experiencing Rapid Channeling.

Figs. 65, 66, 67, 68, 69, 70, 71, and **72** 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.

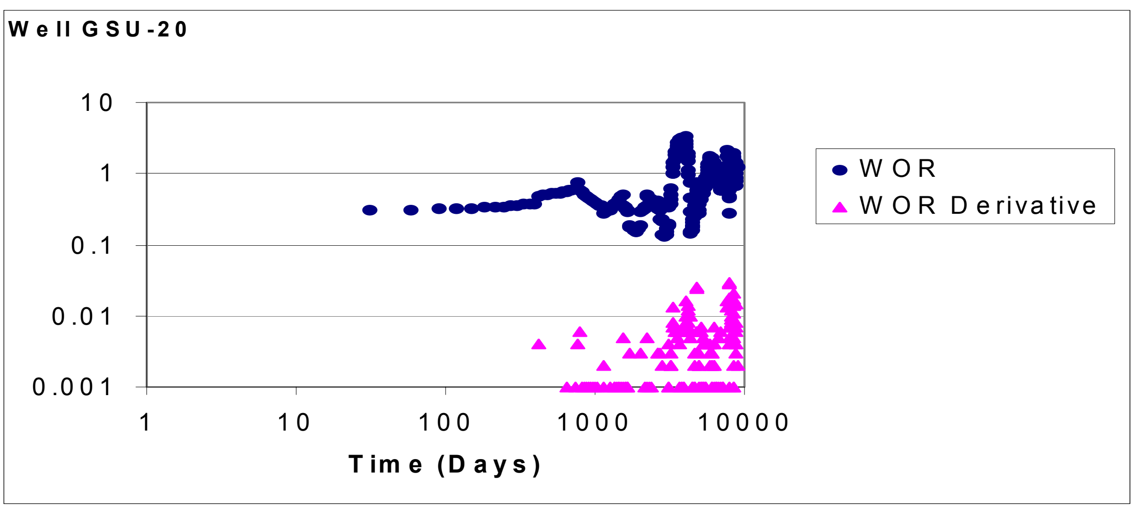

Fig. 65 -WOR and WOR Derivative for Well GSU-20: Experiencing Normal Displacement with High WOR.

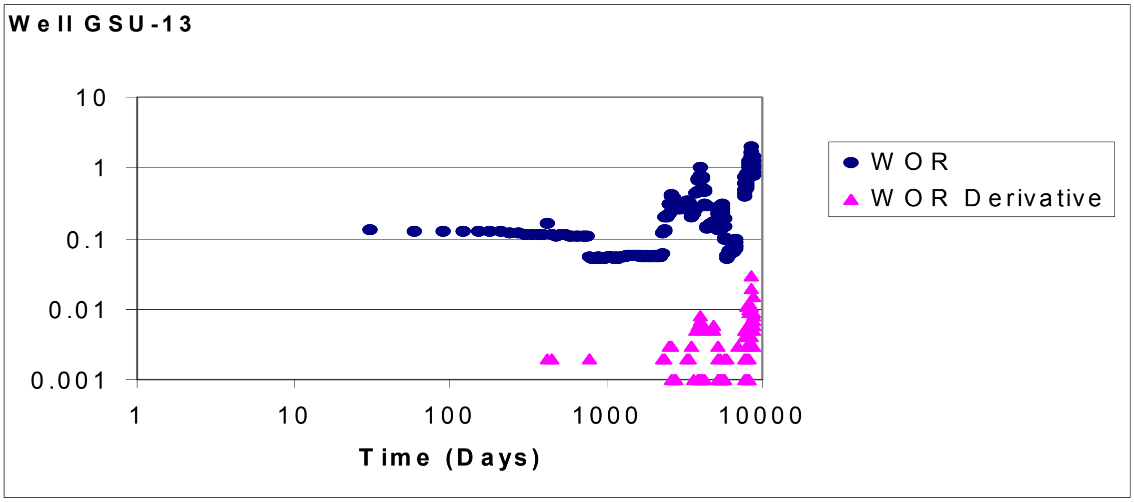

Fig. 66 -WOR and WOR Derivative for Well GSU-13: Experiencing Normal Displacement with High WOR.

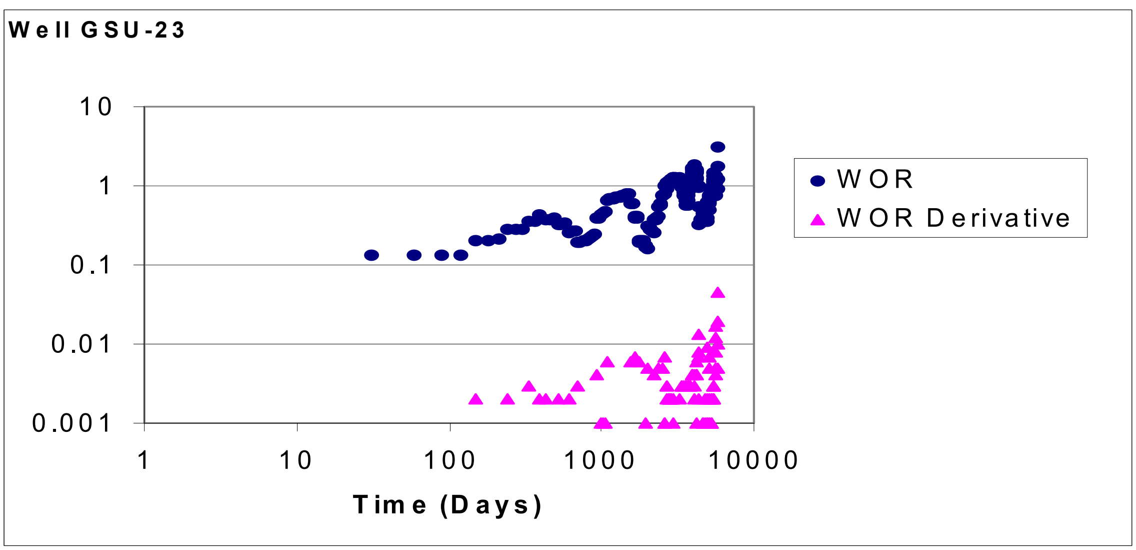

Fig. 67 -WOR and WOR Derivative for Well GSU-23: Experiencing Normal Displacement with High WOR.

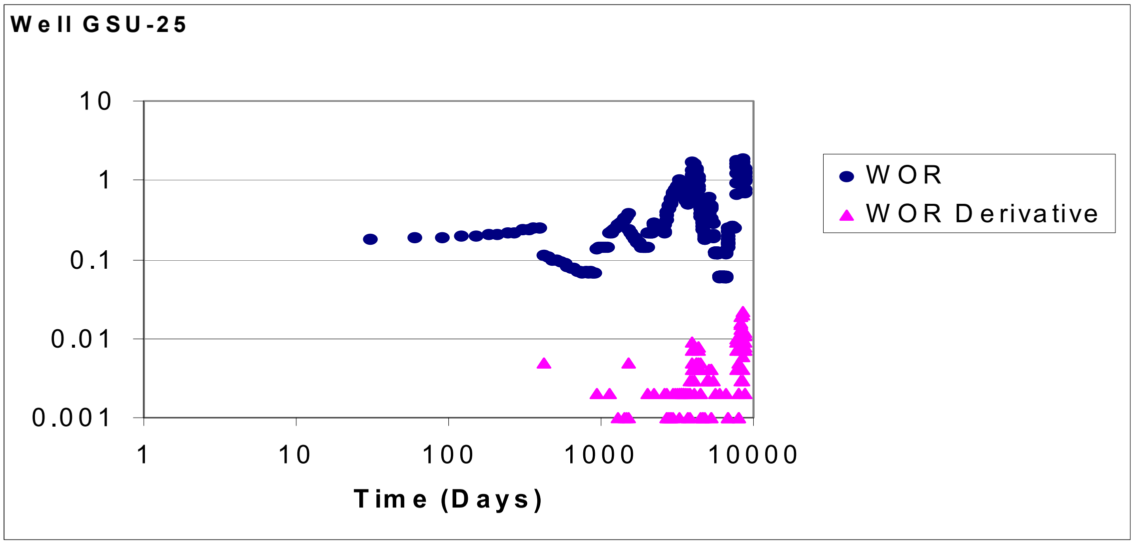

Fig. 68 -WOR and WOR Derivative for Well GSU-25: Experiencing Normal Displacement with High WOR.

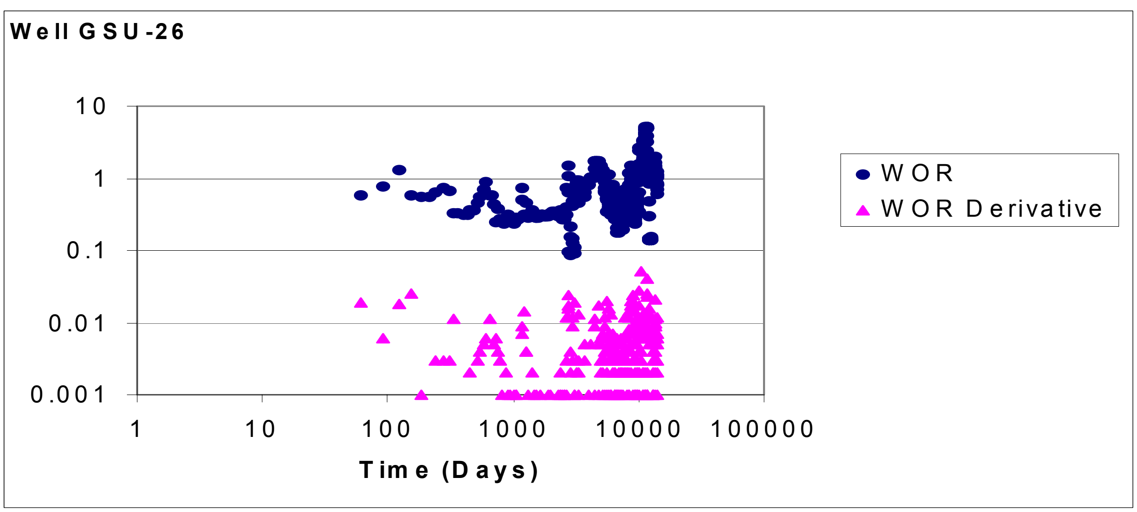

Fig. 69 -WOR and WOR Derivative for Well GSU-26: Experiencing Normal Displacement with High WOR.

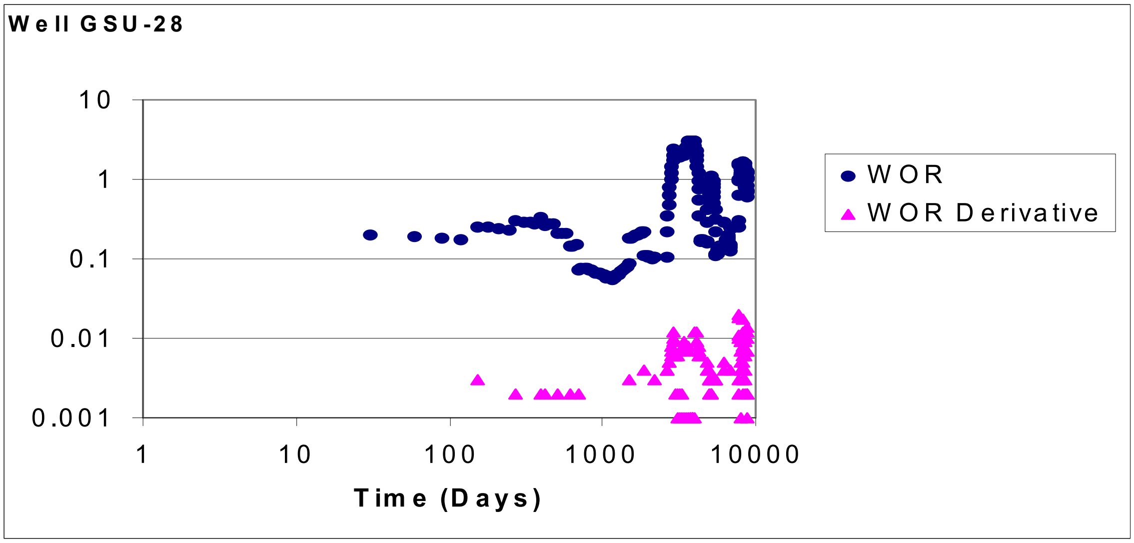

Fig. 70 -WOR and WOR Derivative for Well GSU-28: Experiencing Normal Displacement with High WOR.

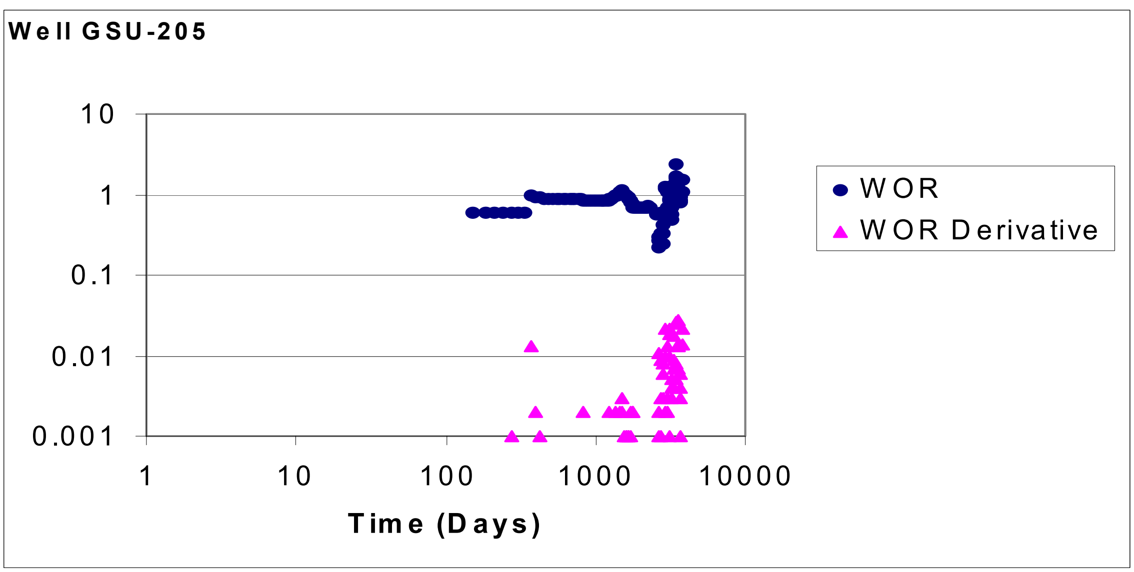

Fig. 71 -WOR and WOR Derivative for Well GSU-205: Experiencing Normal Displacement with High WOR.

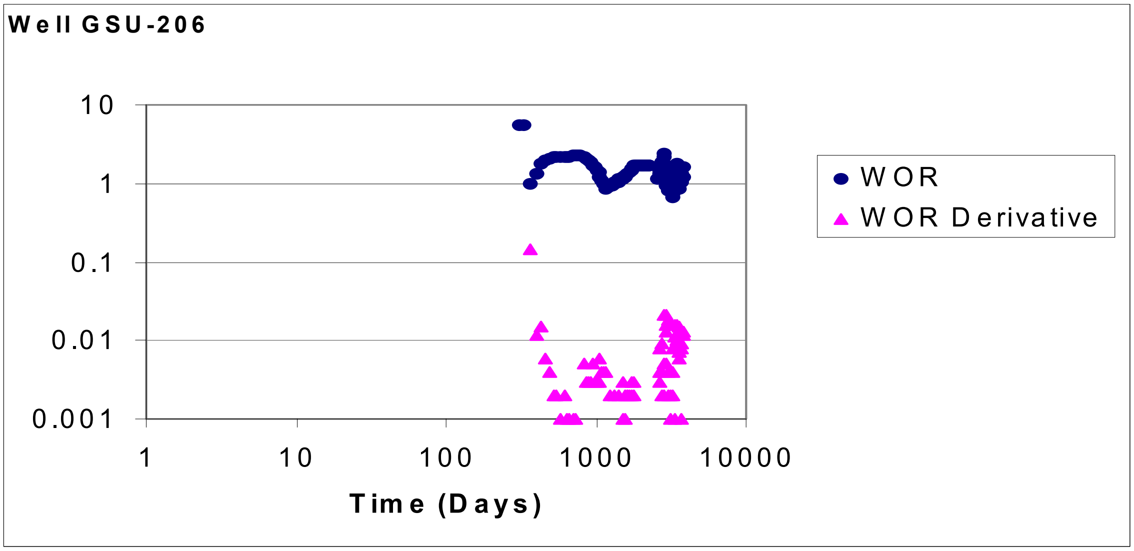

Fig. 72 -WOR and WOR Derivative for Well GSU-206: Experiencing Normal Displacement with High WOR.

Table 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 6- Summary of 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	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

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. 73 shows the scatter plot for all active wells producing in Germania Sprayers Unit. Well GSU-26 has been a good well (has produced 159,000 barrels of oil and 106,000 barrels of water), basically because is located between the injectors GSU-22 and GSU-27 showing a good response to the injection . This is a good well to select the best practices 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).

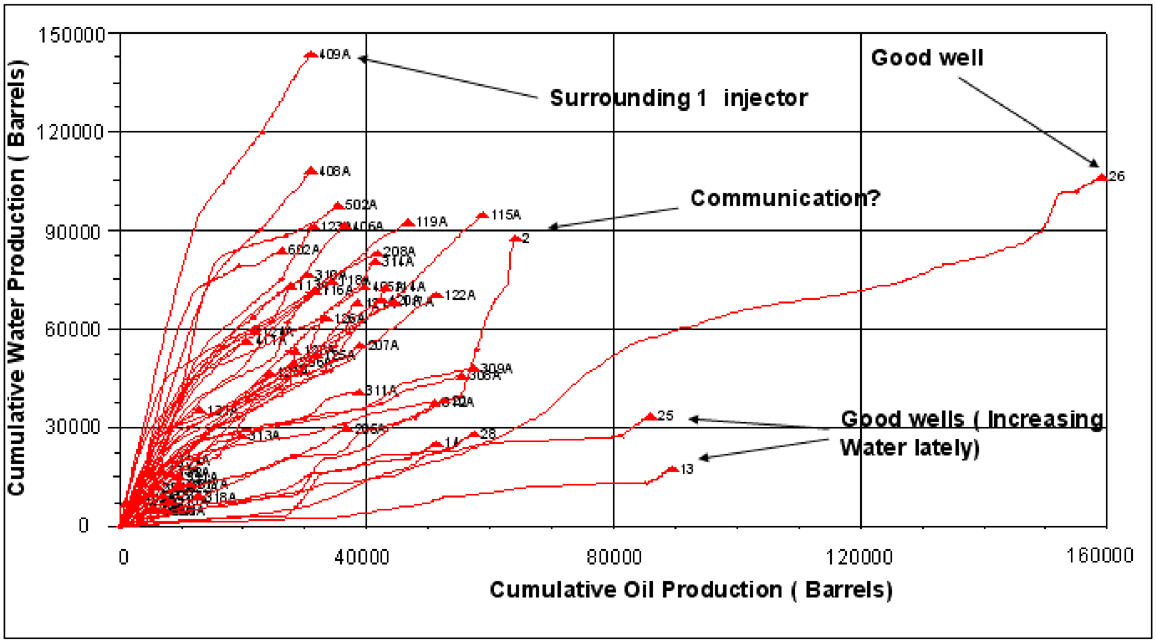

Fig. 73 -Scatter Plot Showing the Performance of Cumulative Oil vs. Cumulative Water for Active Wells in Germania Spraberry Unit.

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.

Figs 74, 75, 76, and **77** show 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 these bubble maps, the central part of the unit is the most depleted. Areas with high cumulative oil correlate to major fracture orientation trend (these areas form an axis parallel to the major fracture orientation trend)

Fig. 78 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 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. 78**) generally correspond to areas of greater net pay in the operational units 1U and 5U (according to Gamma-Ray logs). 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° E) and are also correlative with axes of maximum net pay.

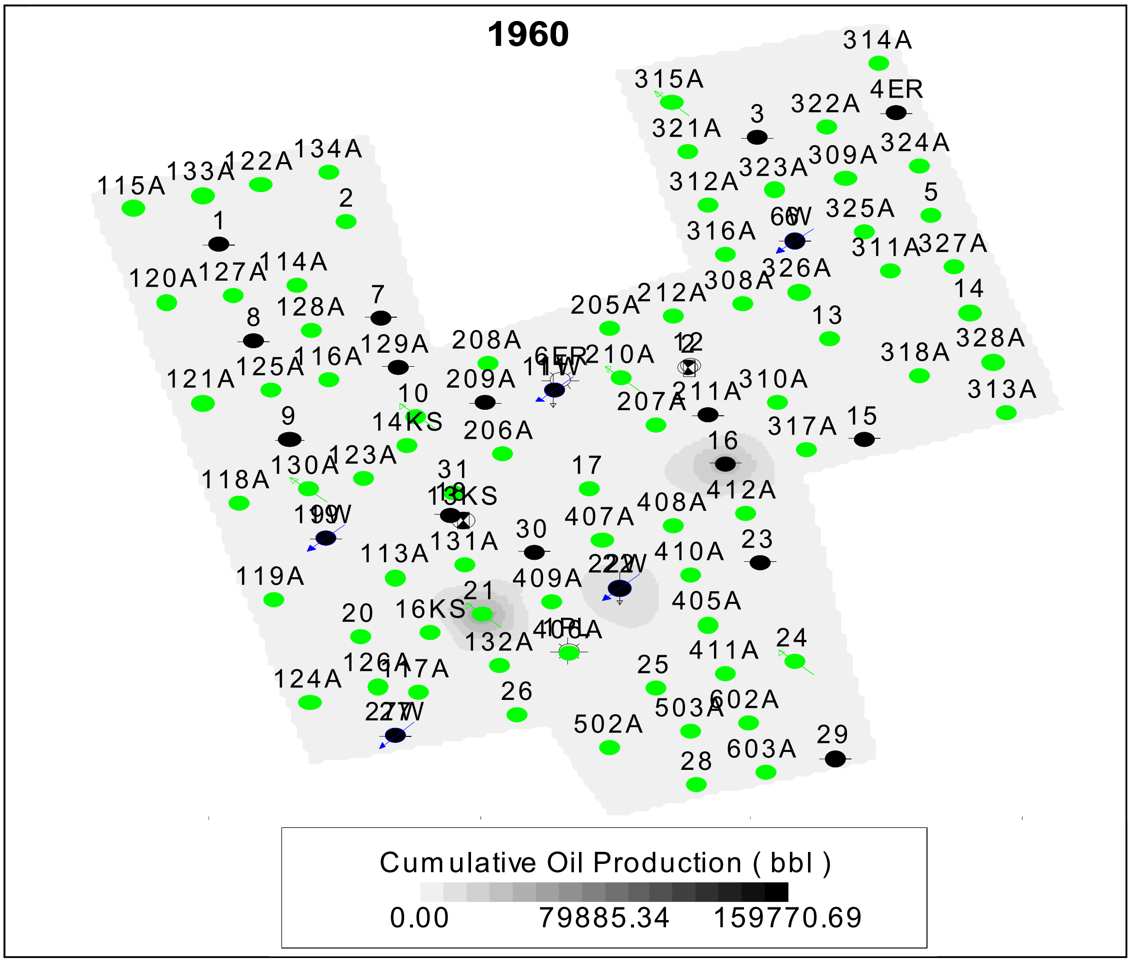

Fig. 74 -Bubble Map of Cumulative Oil Production in Germania Spraberry Unit (1960).

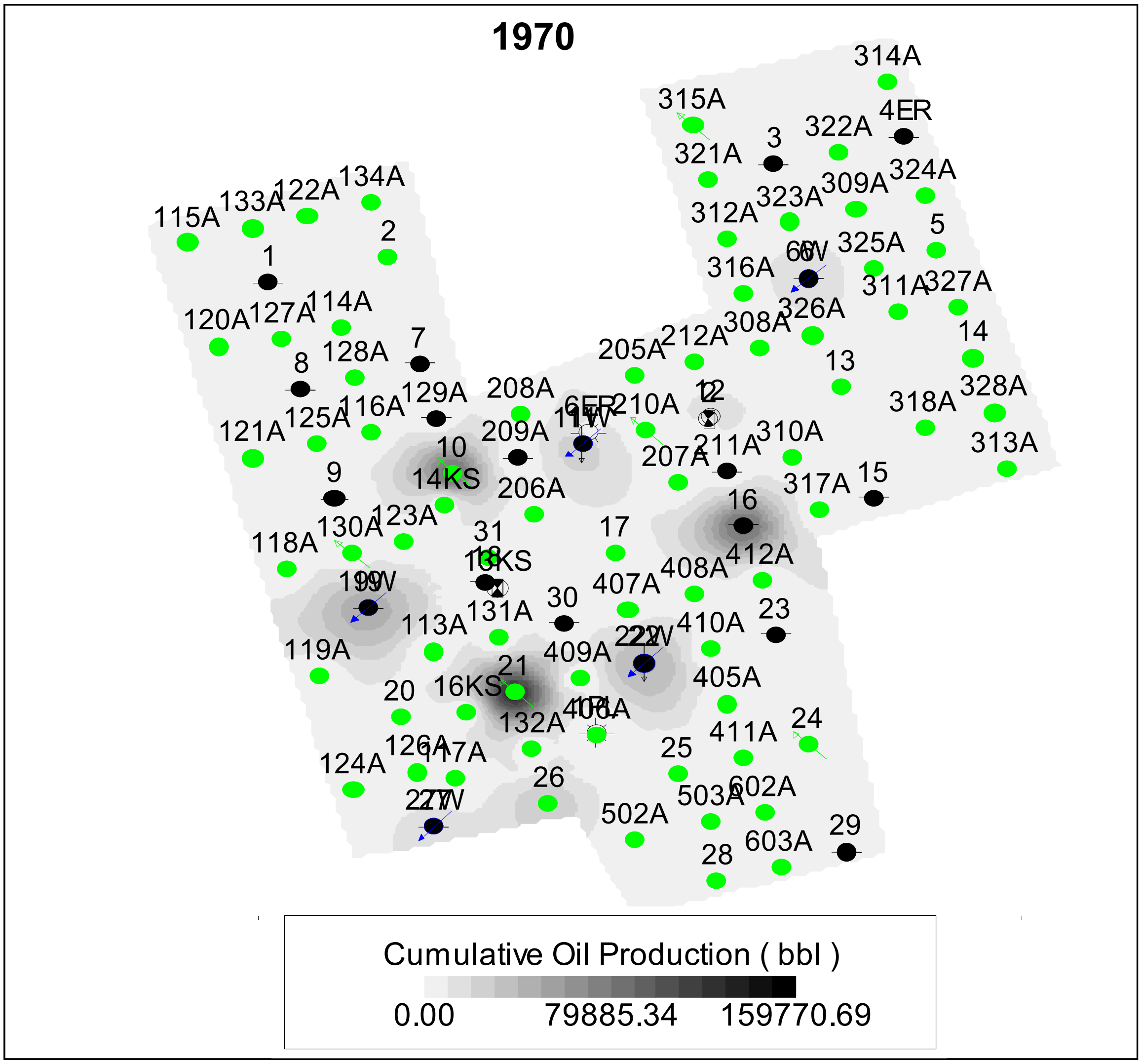

Fig. 75 -Bubble Map of Cumulative Oil Production in Germania Spraberry Unit (1970).

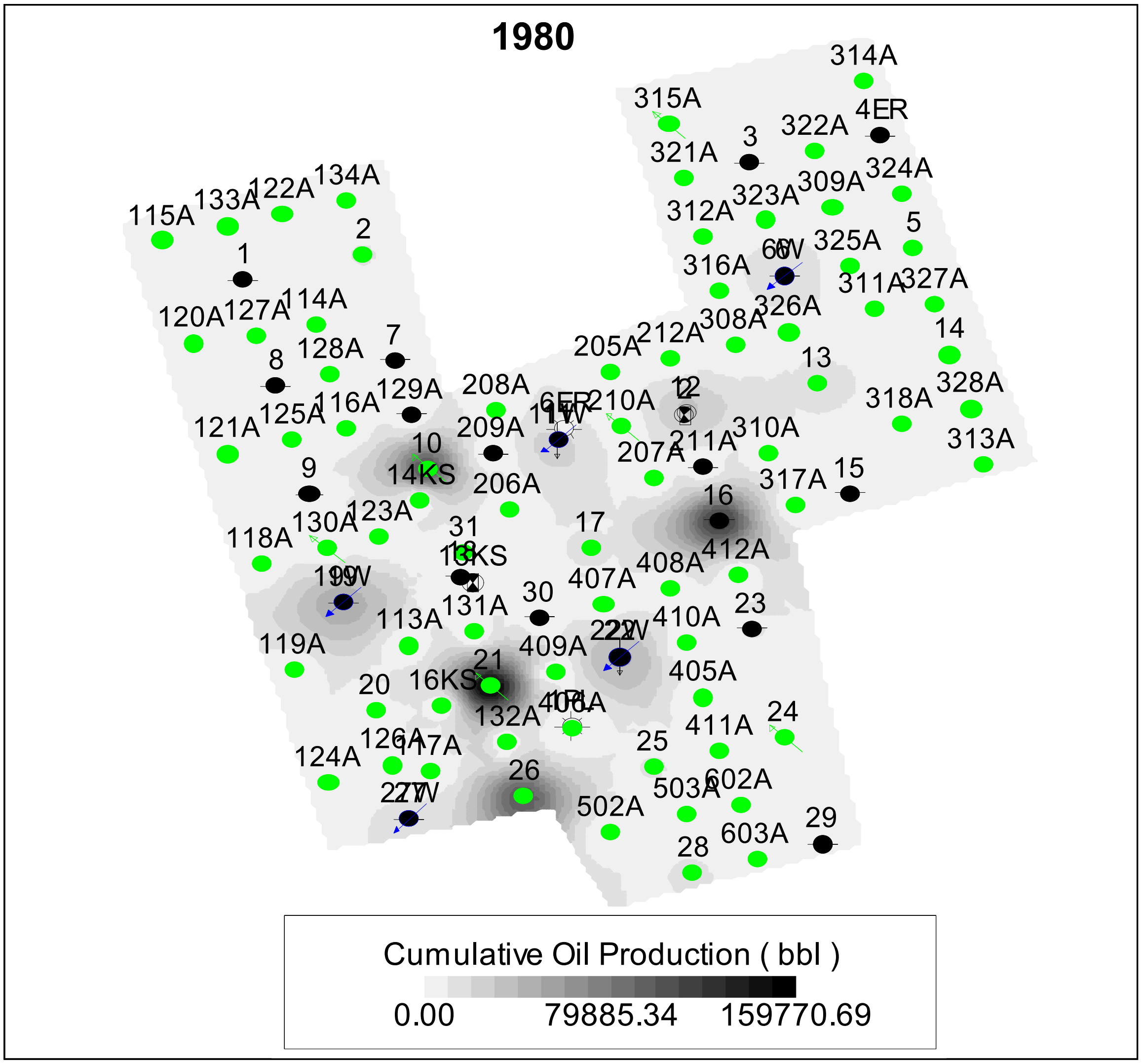

Fig. 76 -Bubble Map of Cumulative Oil Production in Germania Spraberry Unit (1980).

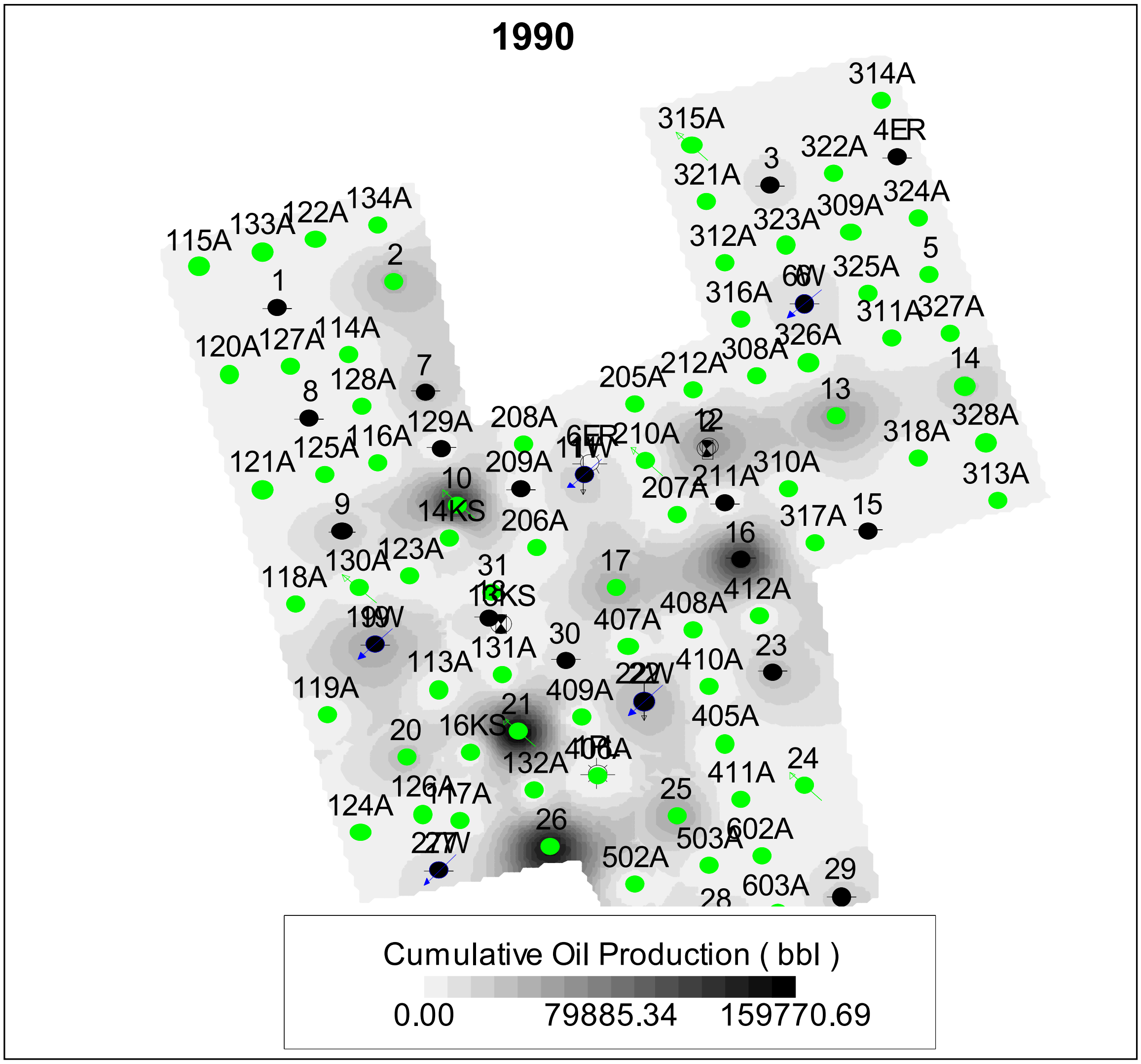

Fig. 77 -Bubble Map of Cumulative Oil Production in Germania Spraberry Unit (1990).

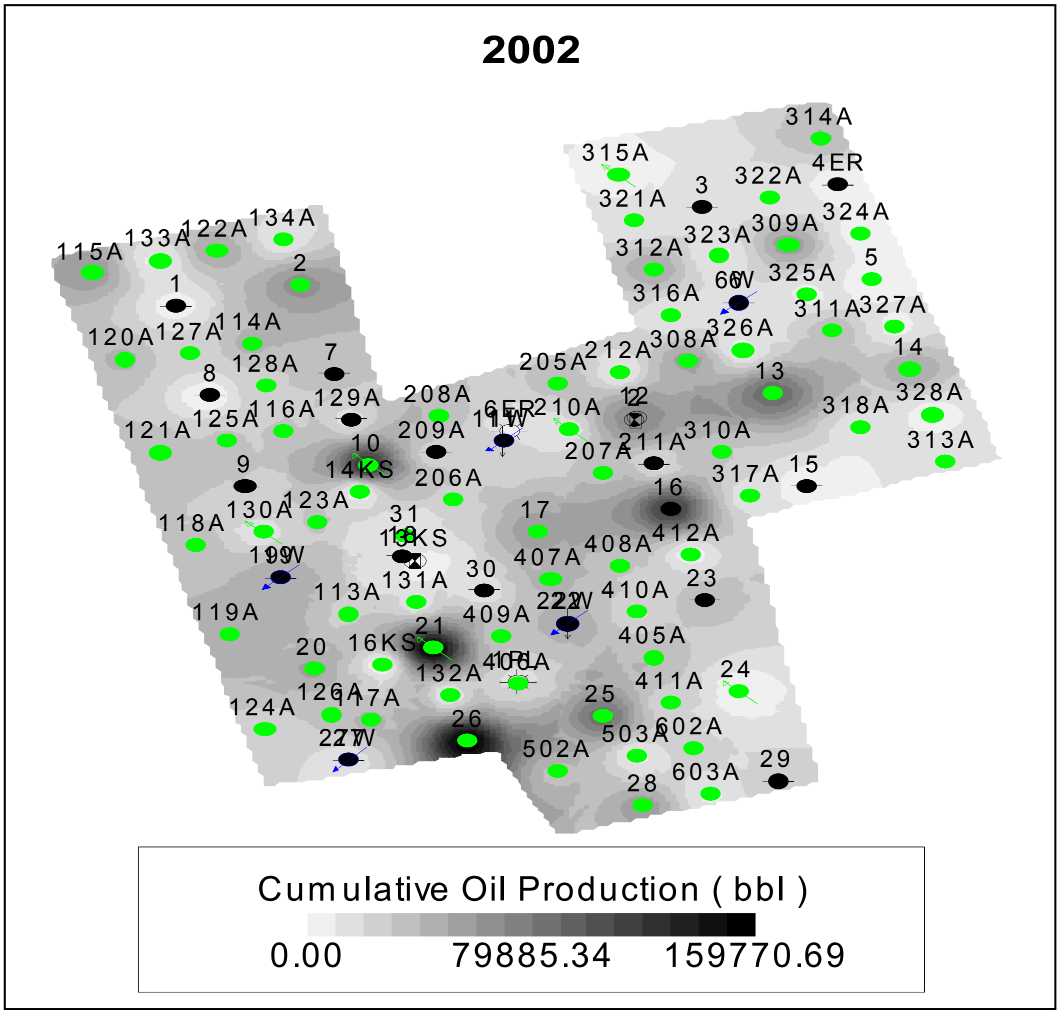

Fig. 78 -Bubble Maps of Cumulative Oil Production in Germania Spraberry Unit (2002).

Figs 79, 80, 81, and **82** show 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. According to these bubble maps, the central part of the unit is the most drained. Areas with high cumulative water correlate to major fracture orientation trend (these areas form an axis parallel to the major fracture orientation trend).

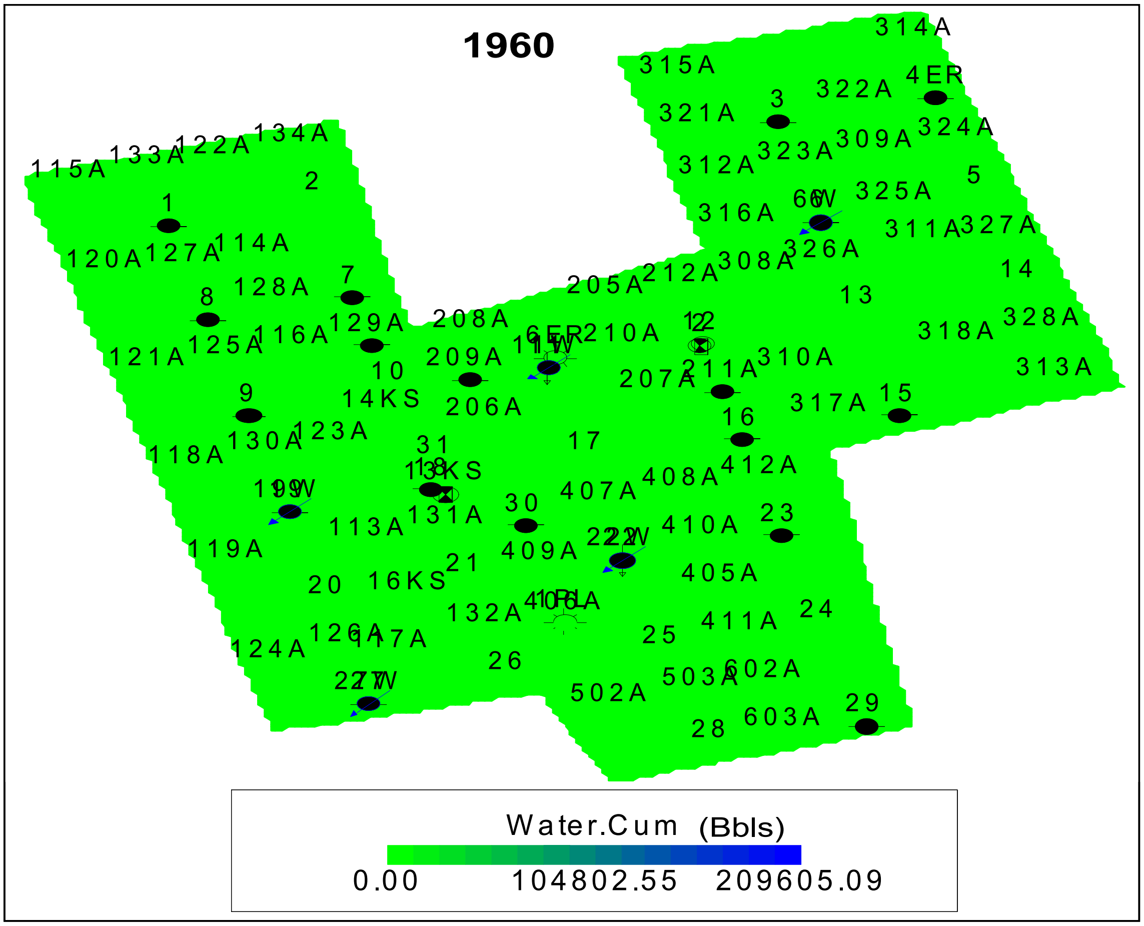

Fig. 79 -Bubble Maps of Cumulative Water Production in Germania Spraberry Unit (1960).

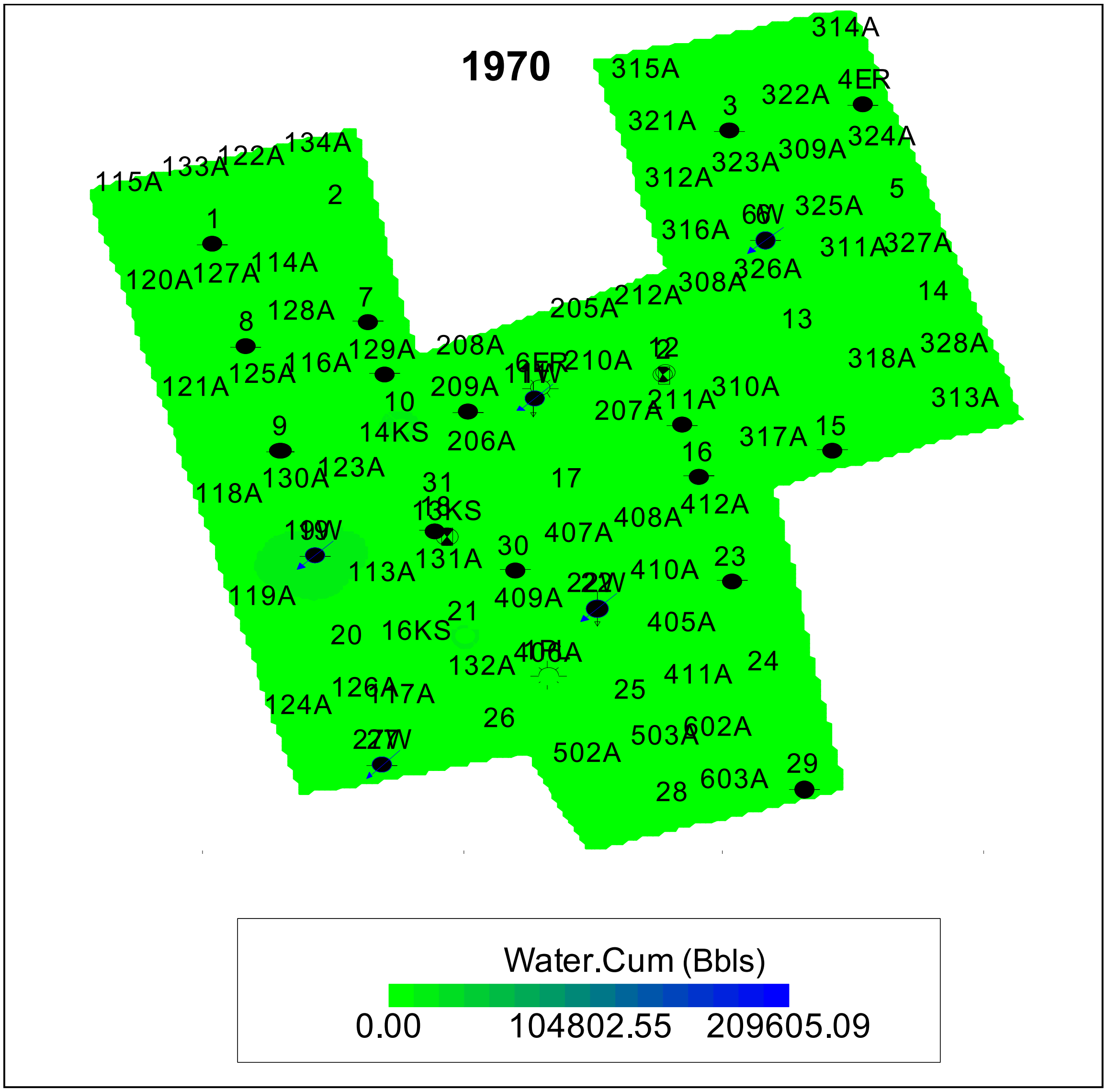

Fig. 80 -Bubble Maps of Cumulative Water Production in Germania Spraberry Unit (1970).

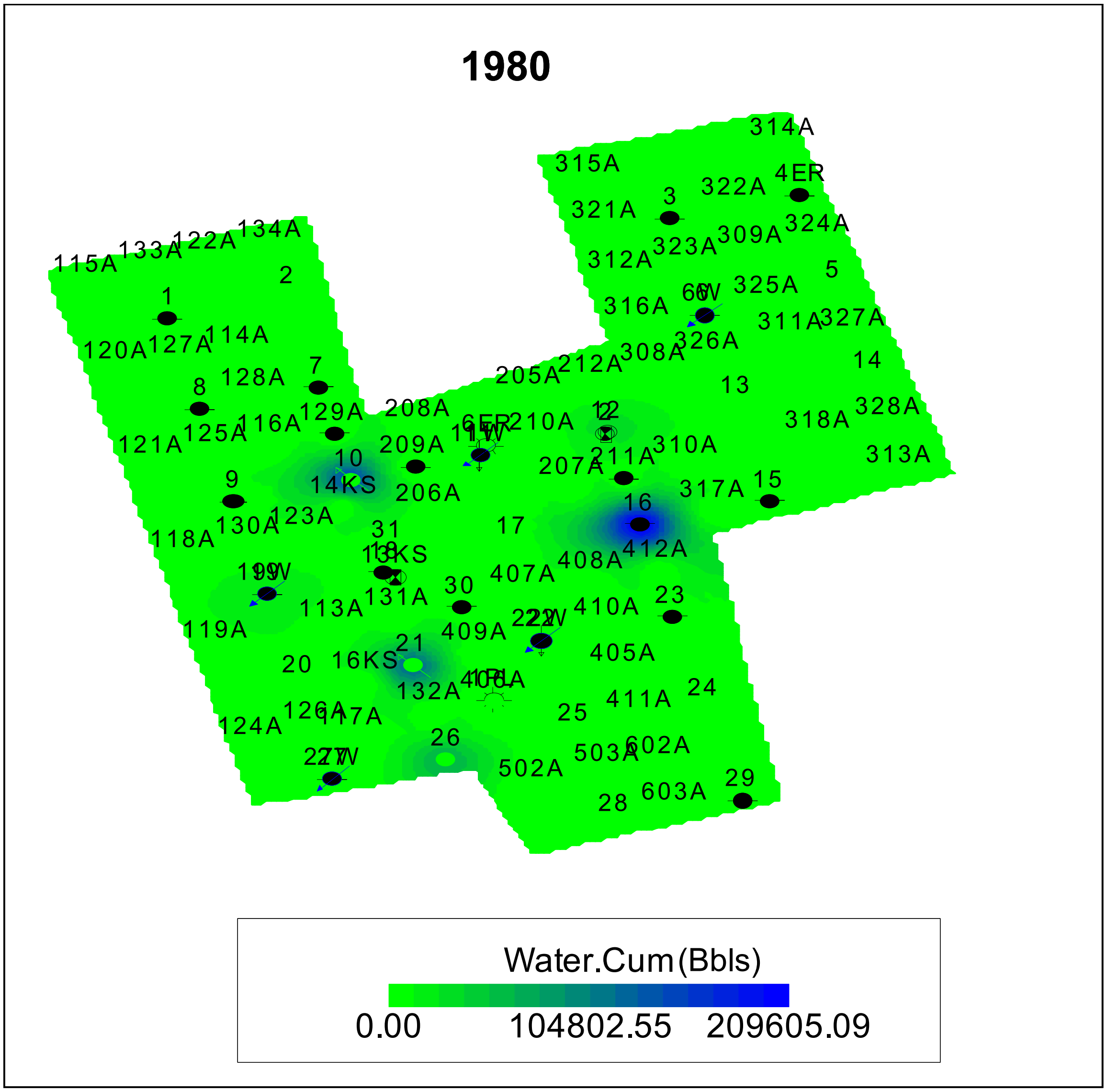

Fig. 81 -Bubble Maps of Cumulative Water Production in Germania Spraberry Unit (1980).

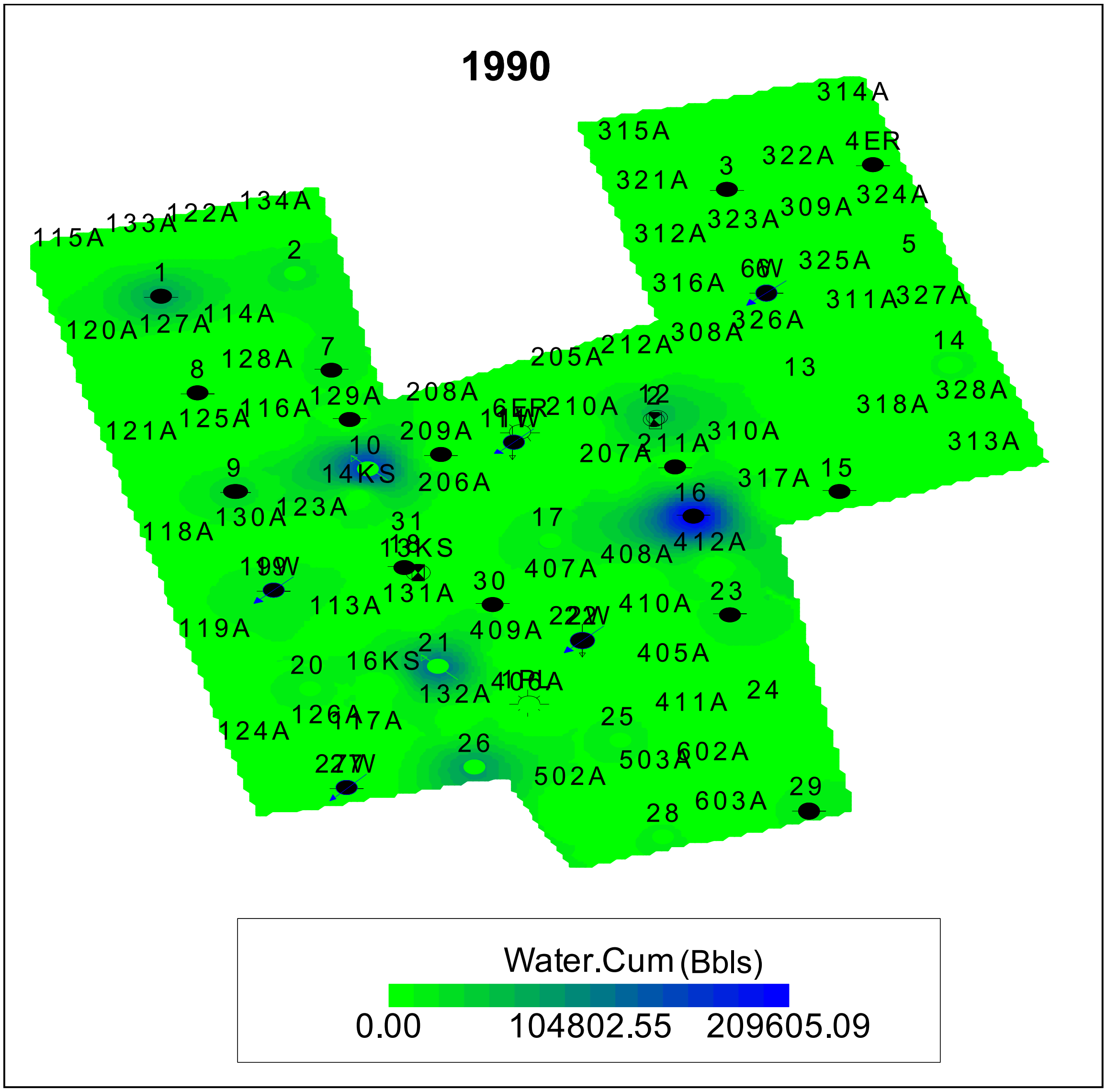

Fig. 82 -Bubble Maps of Cumulative Water Production in Germania Spraberry Unit (1990).

Fig. 83 shows the cumulative water production at last date of production (2002)**.** This maps also show correlation between the cumulative water production and the main fracture trend and also suggests that the area surrounding well GSU-1 (the area that exhibits the highest cumulative water) is an indication of communication problems in this well (this is in accordance with the diagnostic obtained using water control diagnostic plots for this well).

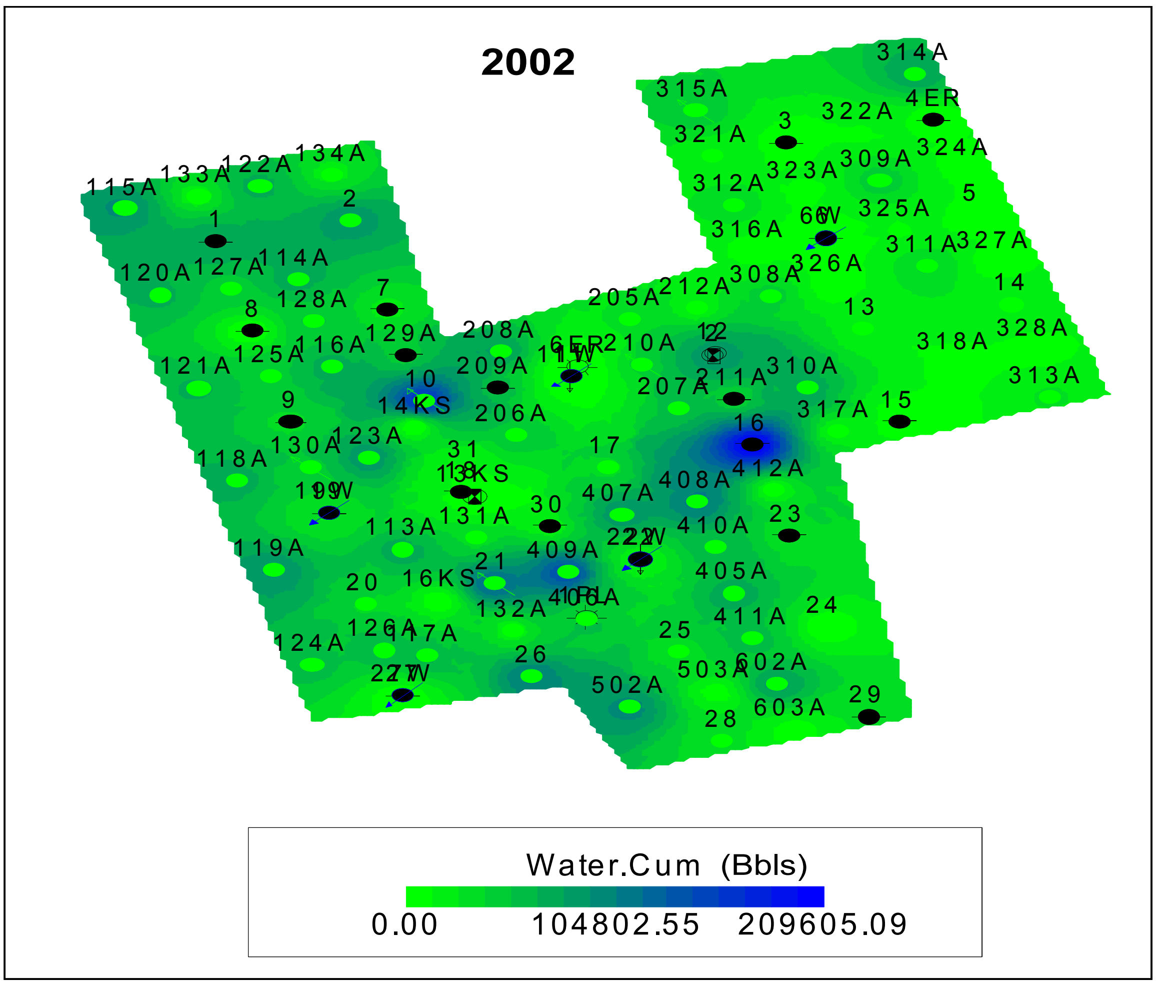

Fig. 83 - Bubble Maps of Cumulative Water Production in Germania Spraberry (2002).

CHAPTER V
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. The literature provides several approaches to determine the hyperbolic decline-curve parameters necessary to apply equation (4.4). In this case we estimated the parameters by plotting the oil rate for every well vs. time and then matched the past performance for every well by using regression analysis. We found that in most cases the value that best fit the data (past performance) is a value of b equal to 0.7 which indicates exponential decline. This value also yields a value of regression coefficient (R^2) equal to 0.9997914 that indicates that the optimum fit was made. Using the value of b equal to 0.7, 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:

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

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:

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

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 84, 85, 86, 87, 88, and 89 show the remaining reserves estimated with equation **4.5** for every well and its corresponding produced reserves (as of June 2003)

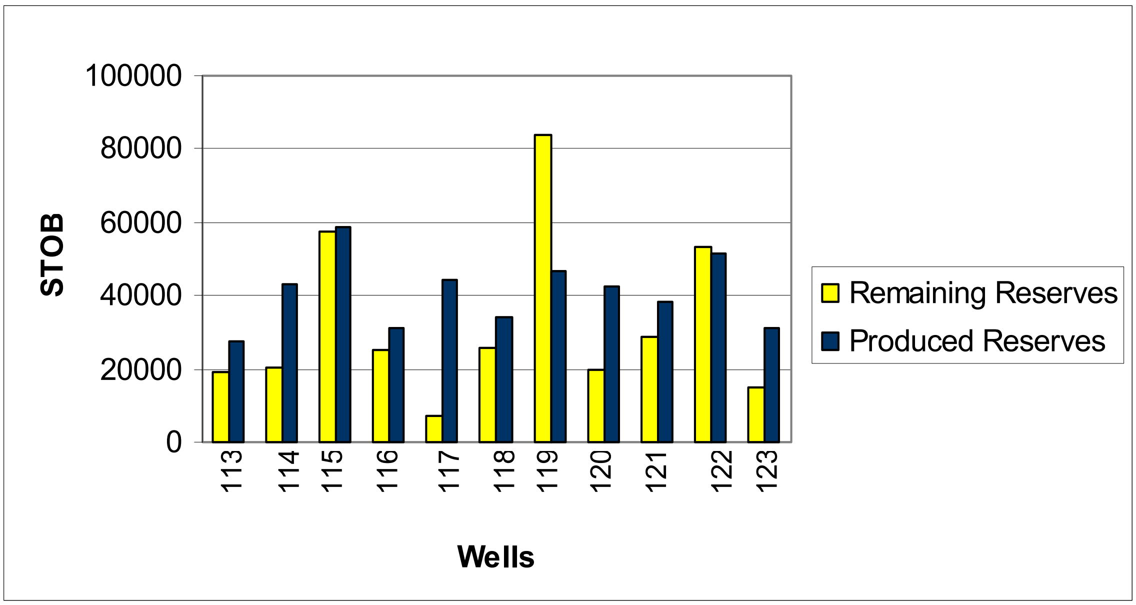

Fig. 84 - Remaining and Produced Reserves for Wells GSU-113,GSU-114,GSU-115,GSU-116,GSU-117,GSU-118,GSU-119,GSU-120,GSU-121,GSU-122, and GSU-123.

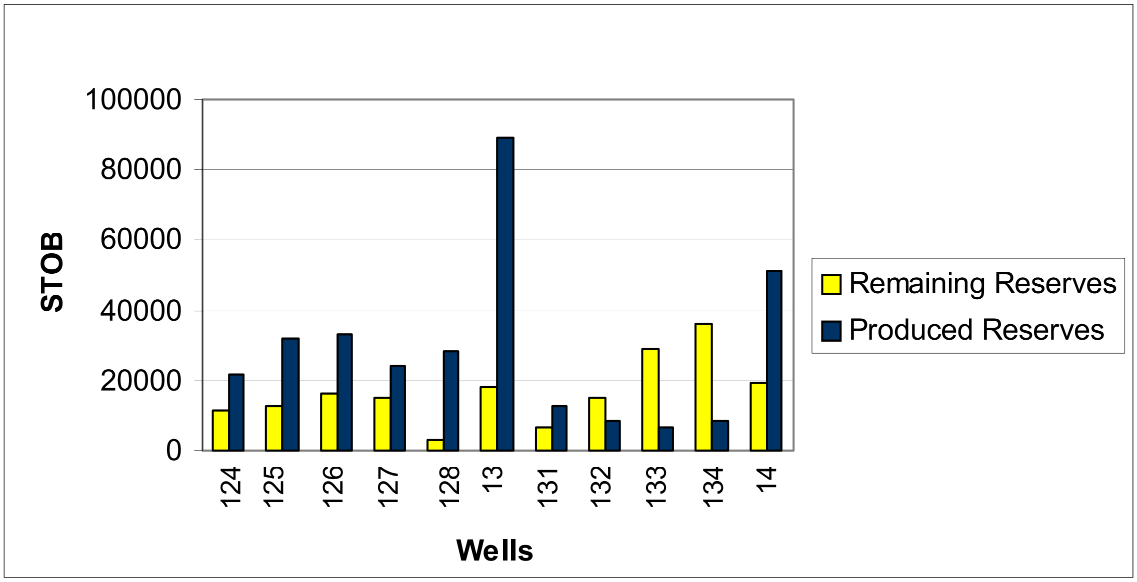

Fig. 85 - Remaining and Produced Reserves for Wells GSU-124,GSU-125,GSU-126,GSU-127,GSU-128,GSU-13,GSU-131,GSU-132,GSU-133,GSU-134, and GSU-14.

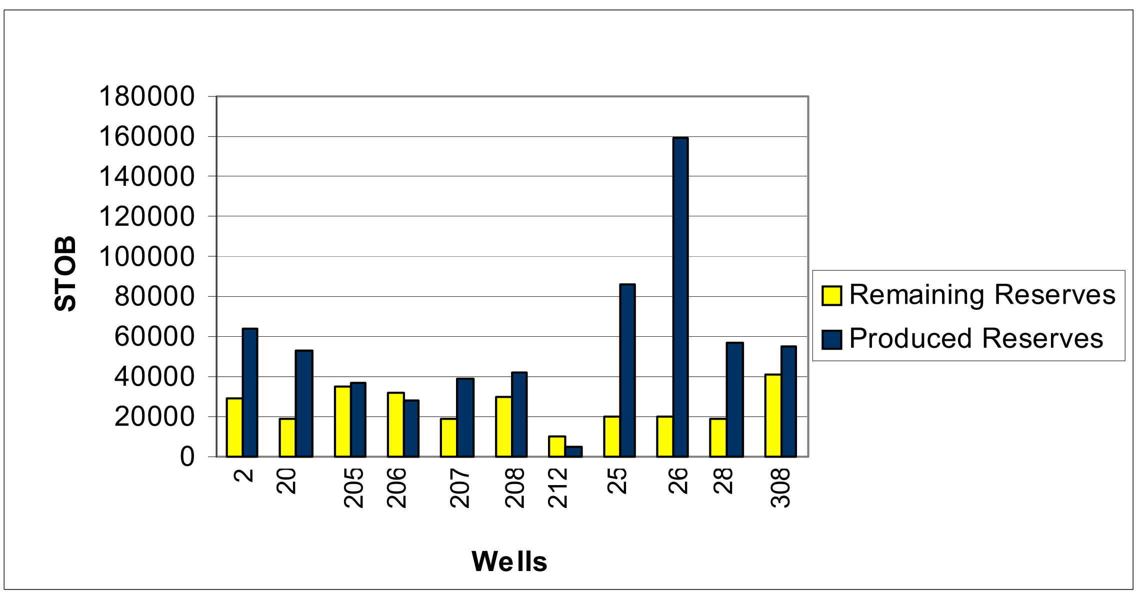

Fig. 86 - Remaining and Produced Reserves for Wells GSU-2,GSU-20,GSU-205,GSU-206,GSU-207,GSU-208,GSU-212,GSU-25,GSU-26,GSU-28, and GSU-308.

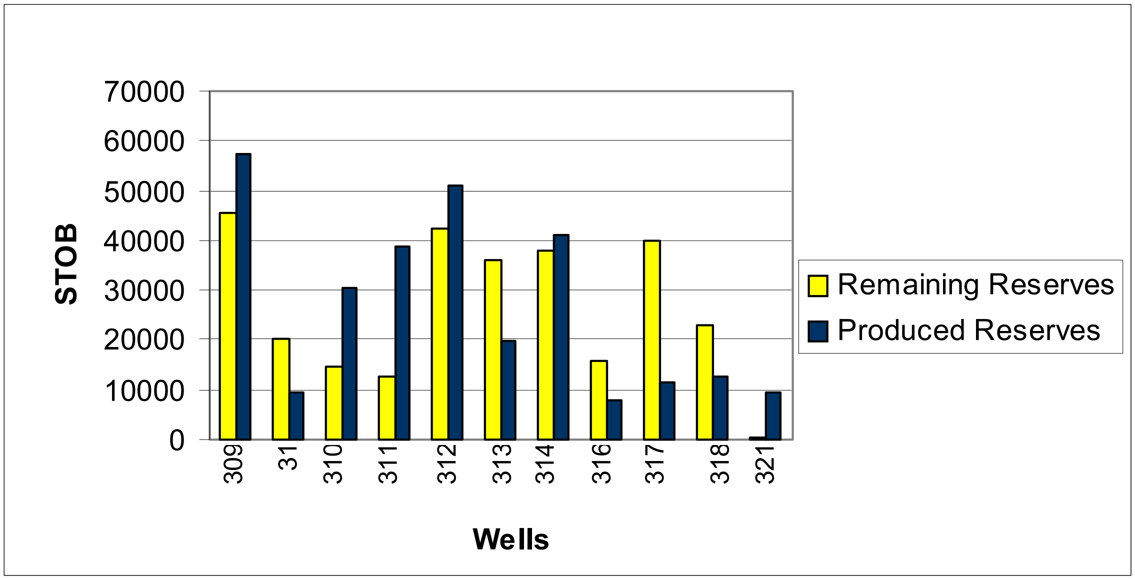

Fig. 87 - Remaining and Produced Reserves for Wells GSU-309,GSU-31,GSU-310,GSU-311,GSU-312,GSU-313,GSU-314,GSU-316,GSU-317,GSU-318, and GSU-321.

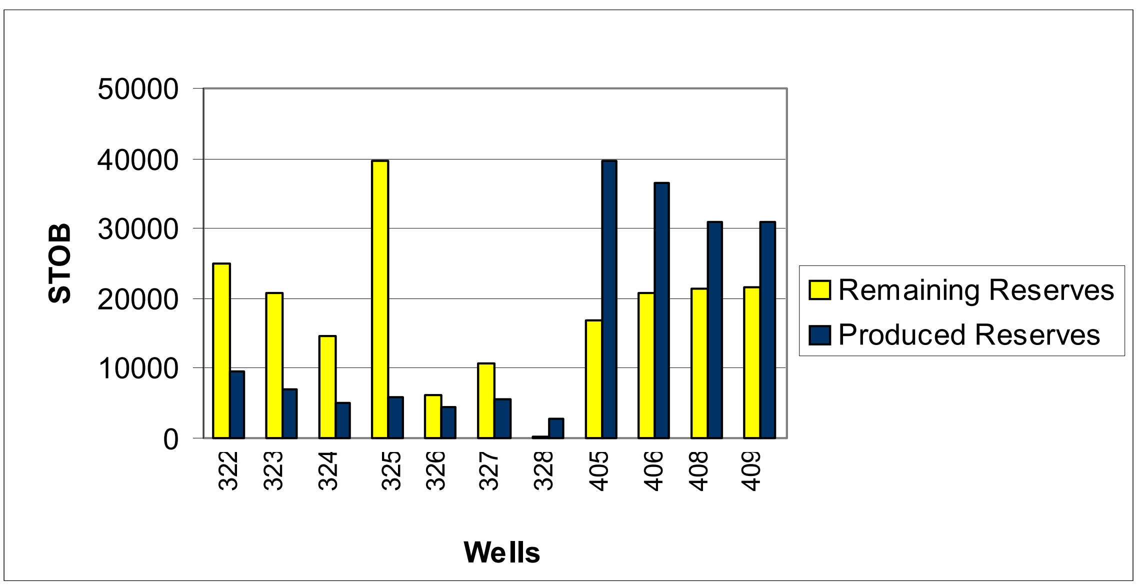

Fig. 88 - Remaining and Produced Reserves for Wells GSU-322, GSU-323, GSU-324, GSU-325, GSU-326, GSU-327, GSU-328, GSU-405, GSU-408, and GSU-409.

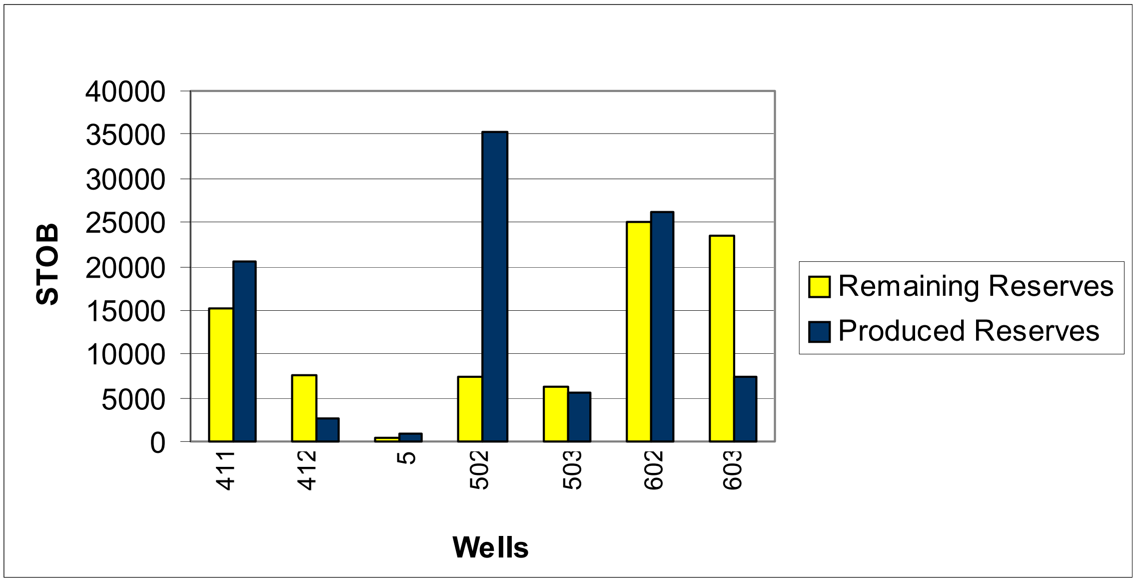

Fig. 89 - Remaining and Produced Reserves for Wells GSU-411,GSU-412,GSU-5,GSU-502,GSU-503,GSU-602, and GSU-603.

We also plotted the results of both remaining reserves and estimated ultimate recovery for every active well in a bubble map. **Fig. 90** and **91** 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.

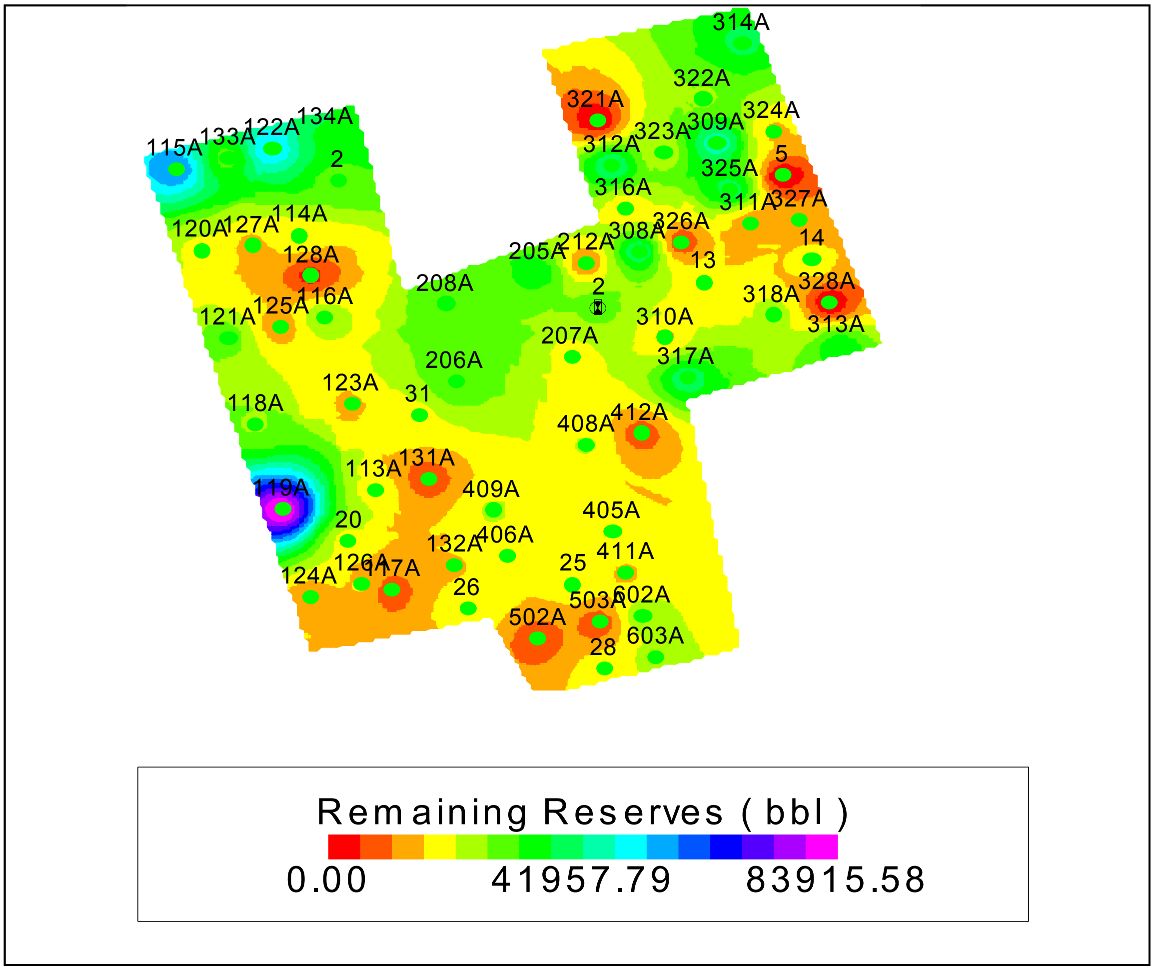

Fig. 90 - Bubble Maps of Remaining Reserves Associated to Active Wells in Germania Spraberry Unit.

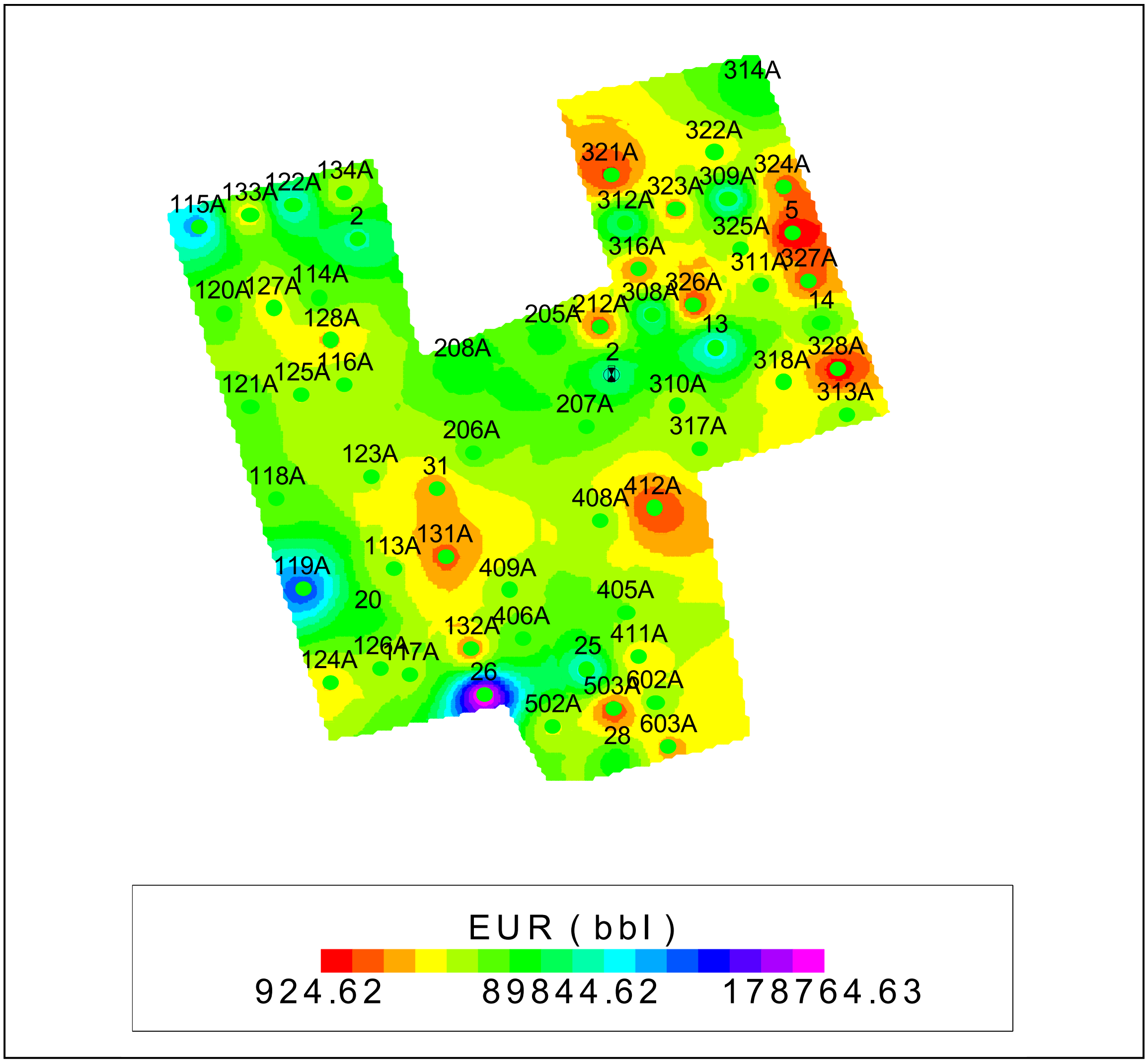

Fig. 91 - Bubble Maps of Estimated Ultimate Recovery (EUR) for Active Wells in Germania Spraberry Unit.

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. 92** illustrates this analysis**.** The extrapolation (dash line is done from the current cumulative production of 3.12 million barrels until reaching economic limit of WOR equal to 50). These results suggest that the unit will be most likely producing and additional 0.98 million barrels through the well currently active. The figure also illustrates the impact of the different drilling programs on the recovery. This analysis also suggests that a new infill drilling program (reducing the wells spacing) targeting the areas with the most remaining reserves "sweet spots" showed in **Fig. 90** would have a great impact on the production and recovery.

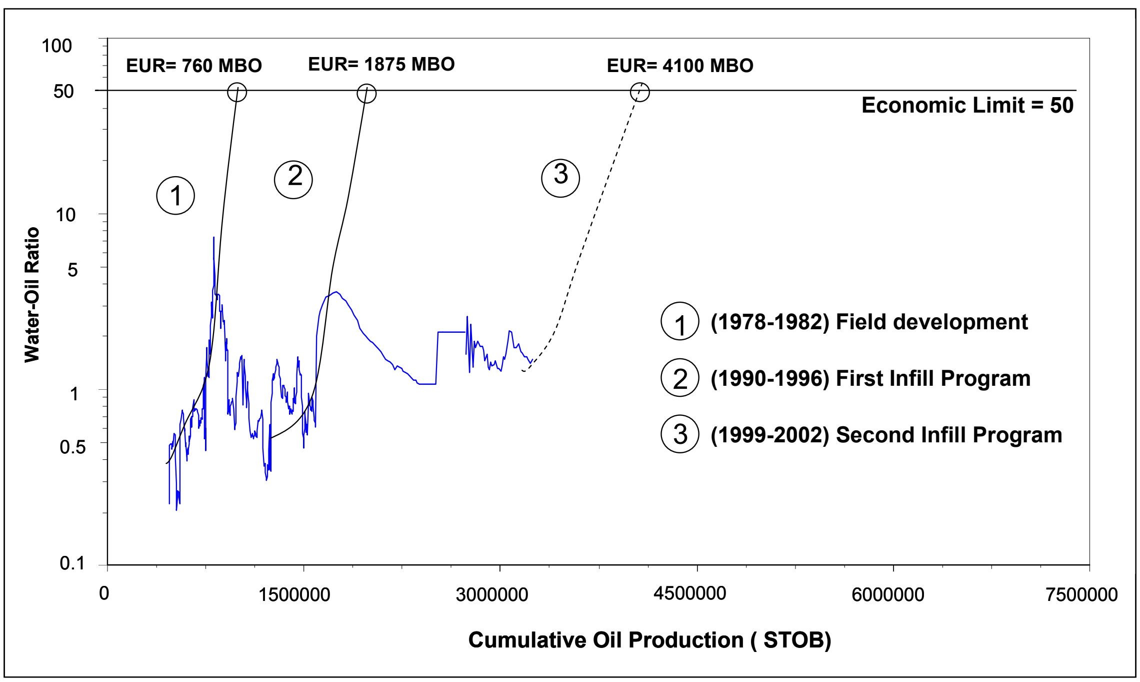

Fig. 92 - WOR behavior and Cumulative Oil Production Due to Infill Drilling and Waterflooding in Germania Spraberry Unit.

CHAPTER VI
DEVELOPMENT OPPORTUNITIES

There are some opportunities in Germania Spraberry Unit to increase drainage area through infill drilling. In this case, 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 waterflood recovery and the well spacing.[6] 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 0.760 to 4.100 million barrels by the implementation of these programs (as shown in **Fig. 92**). 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 improve the performance in this unit.

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.

CHAPTER VII
CONCLUSIONS AND RECOMMENDATIONS

The methodology, analyses, and results described here can be used to improve the performance 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:

Conclusions

- Germania Spraberry Unit can be successfully flooded with the new injection pattern and with injection rate of 1600 BWPD. The voidage replacement ratio under this new injection scheme has been very close to one since the new injection scheme was implemented.
- 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.
- Infill-drilling wells reducing the spacing to 20 acres represents an opportunity to improve the performance of the unit.
- The average voidage replacement observed from 1969 to 1975 suggests 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.
- 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-1 may be experiencing casing leak.

- 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.
- 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 may be good candidates for the application of water control techniques.
- 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.).
- Wells drilled in the first program (from 1957 to 1964) have shown the highest value of average initial rate (48 BOPD) and the incremental reserves shown by wells drilled during the third program (from 1990 to 1996) demonstrate the importance and impact of infill drilling in this unit.
- 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° E) and are also correlative with axes of maximum net pay as seen in logs in Germania Spraberry Unit.

Recommendations

- Examine the feasibility of tertiary miscible flooding using CO_2 to reduce the residual oil saturation and improve the performance in the unit after cessation of the waterflooding project.

- Conduct studies of economic evaluation involving risk and uncertainties in the data and economics conditions and considering Infill-drilling wells to reduce the spacing to 20 acres.
- Conduct 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 and possible use of horizontal drilling (targeting the areas with the most remaining reserves) to take advantage of the natural fractures.
- The log-log plot of WOR and its derivative, and Heterogeneity Index, provide some insights and information for well performance evaluation and surveillance system. But, they are not accurate tools for selecting candidates to workover and/or treatments; therefore, they should be used very carefully and must be combined with some tools such as: well file, completion, conventional plots, logs, and geological information to be more effective.

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APPENDIX

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

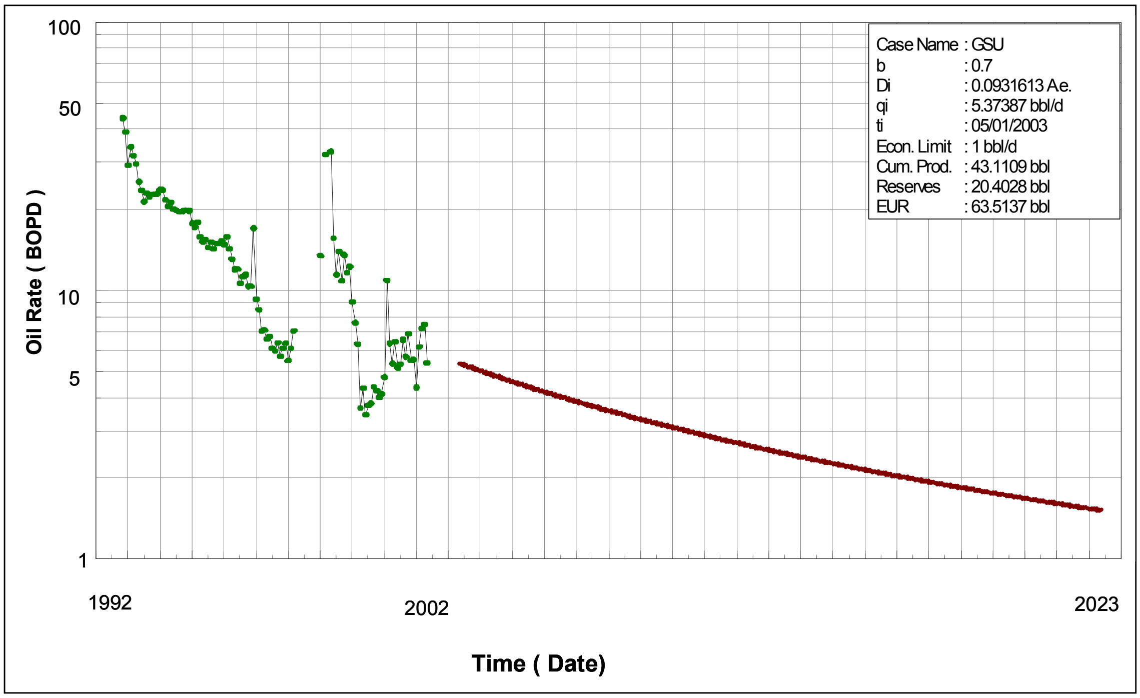

Fig. A. 1- Decline Curve Analysis for Well GSU-114

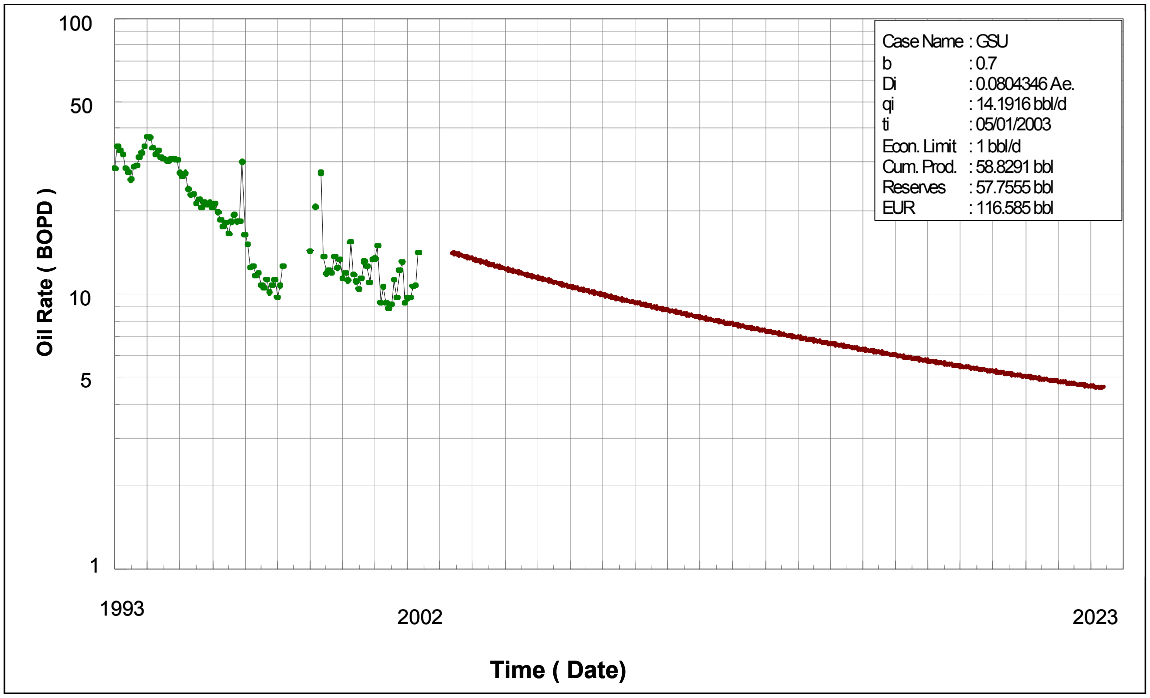

Fig. A. 2-Decline Curve Analysis for Well GSU-115

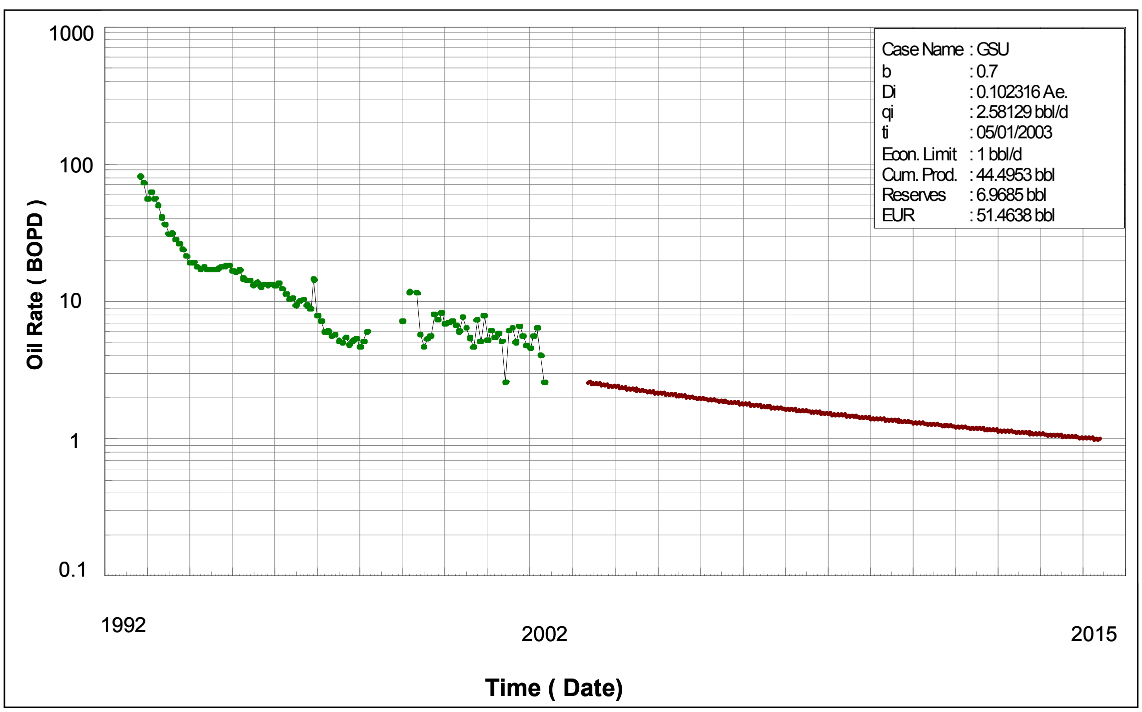

Fig. A. 3- Decline Curve Analysis for Well GSU-117

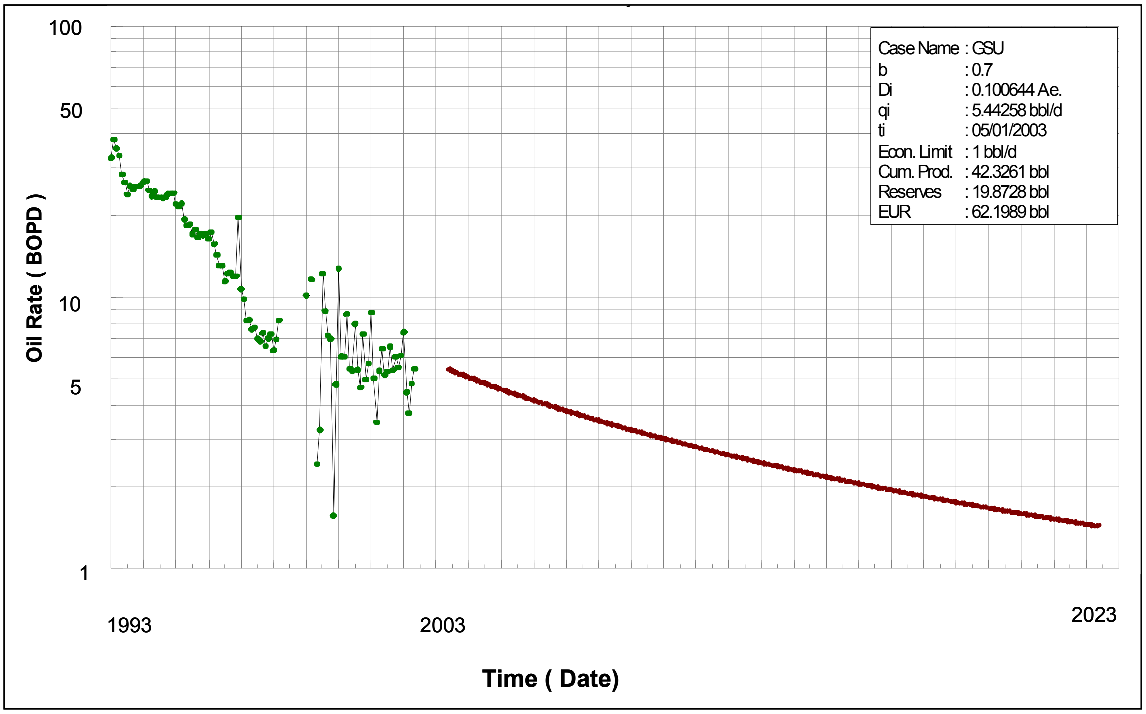

Fig. A. 4- Decline Curve Analysis for Well GSU-120

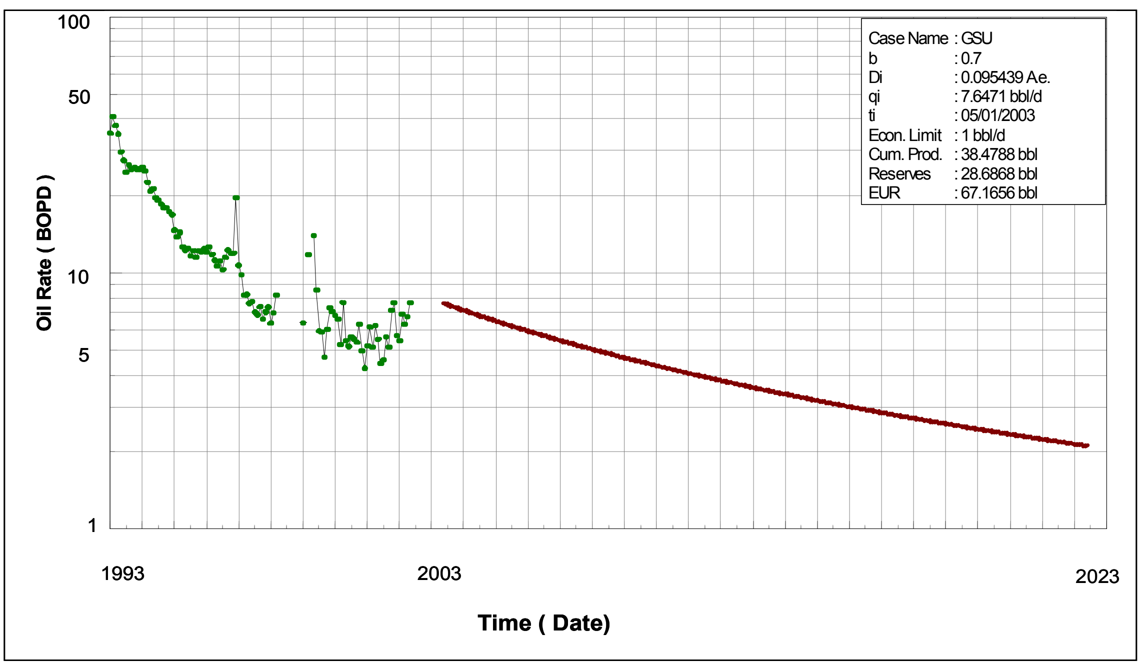

Fig. A. 5- Decline Curve Analysis for Well GSU-121

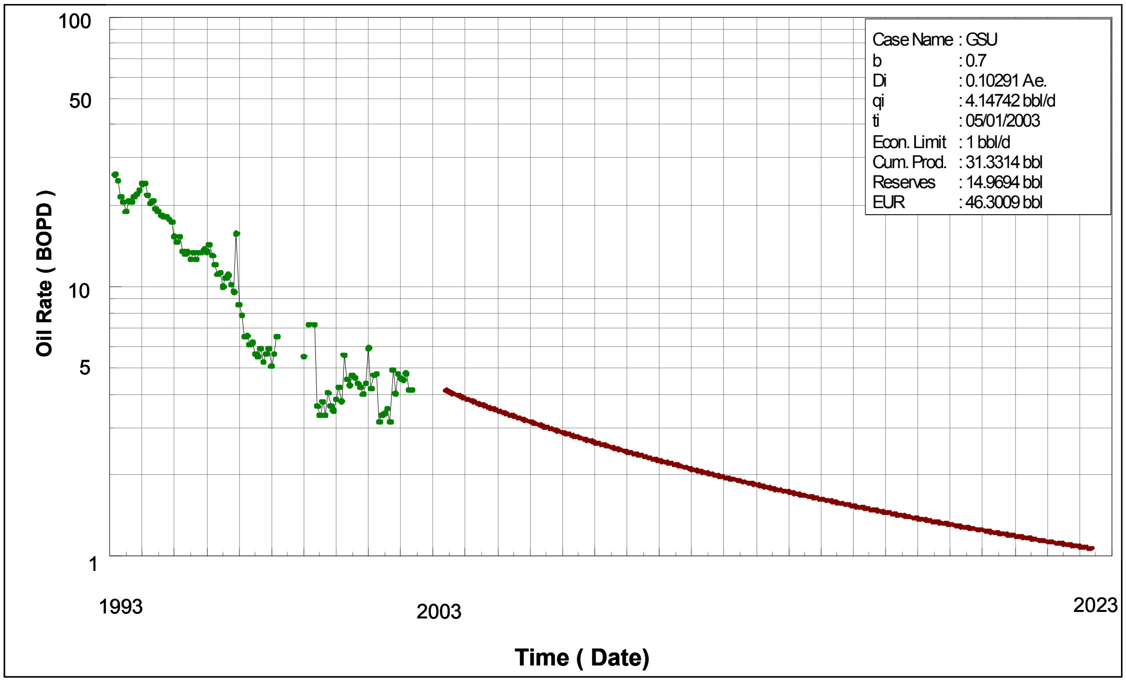

Fig. A. 6- Decline Curve Analysis for Well GSU-123

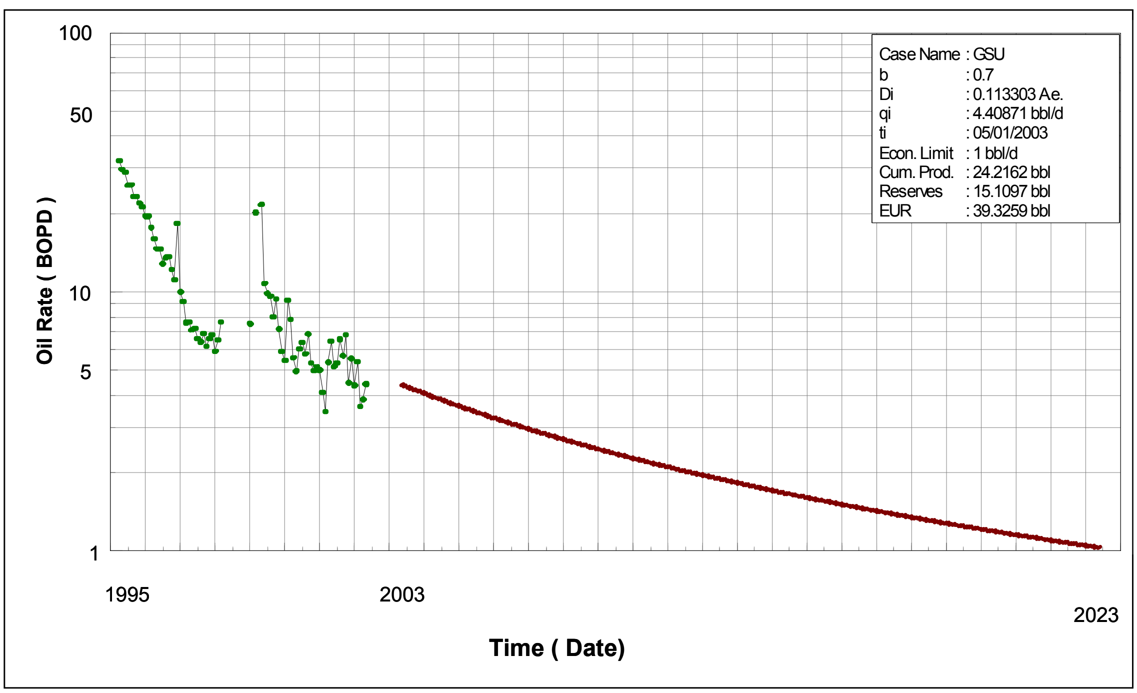

Fig. A. 7- Decline Curve Analysis for Well GSU-127

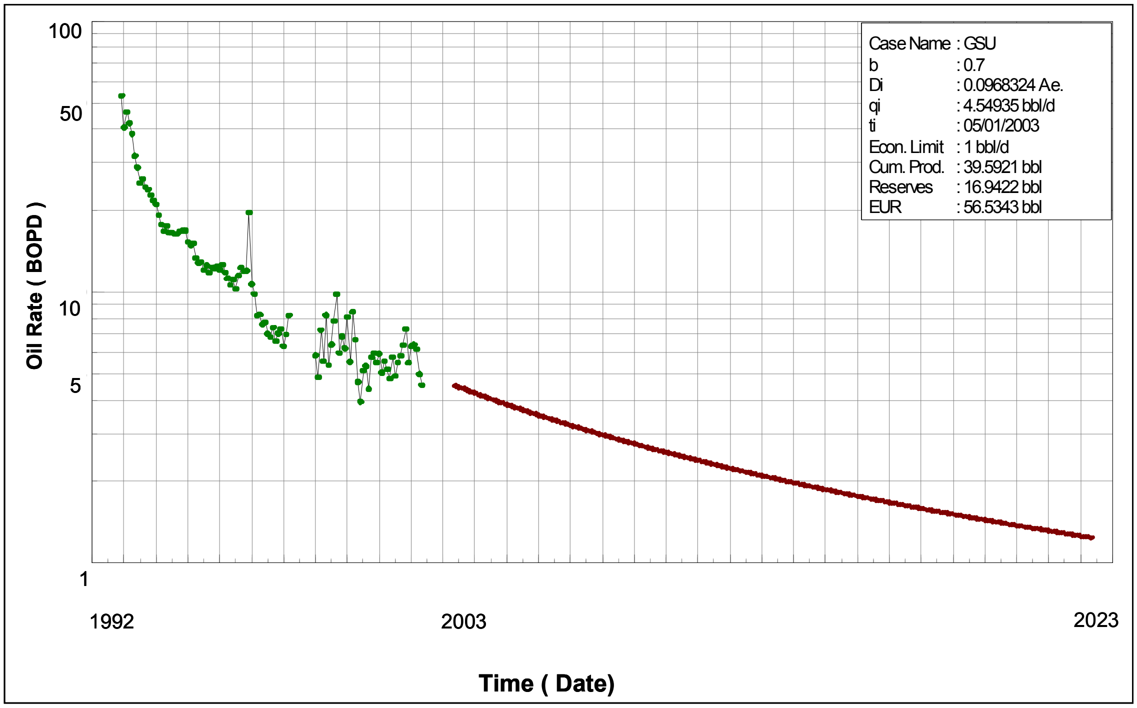

Fig. A. 8- Decline Curve Analysis for Well GSU-405

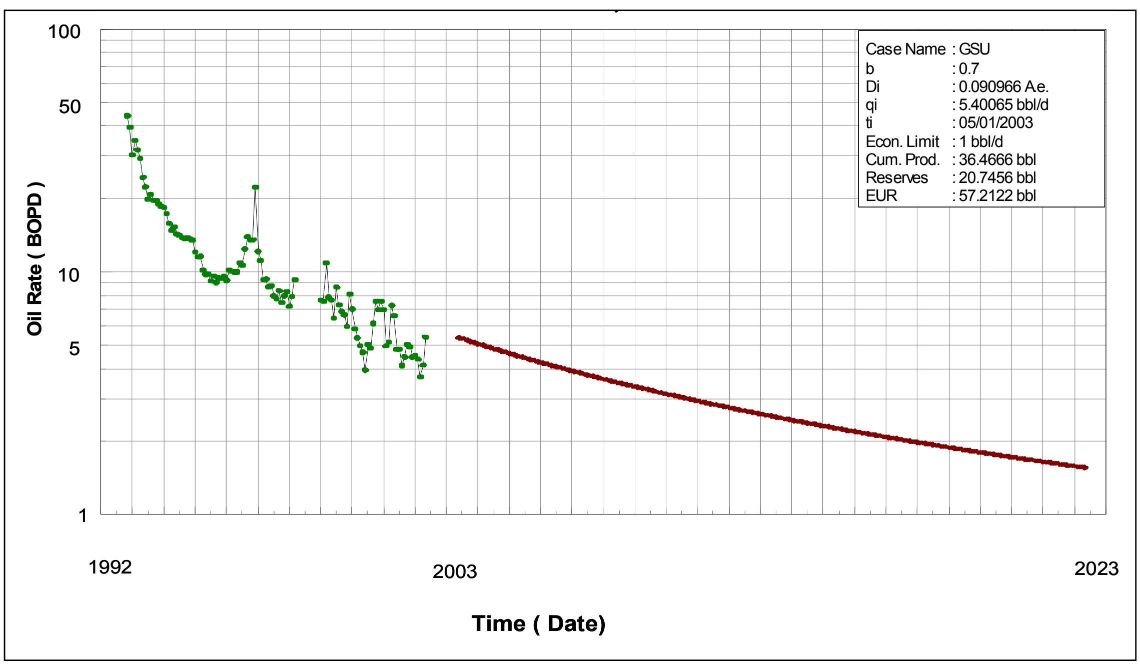

Fig. A. 9- Decline Curve Analysis for Well GSU-406

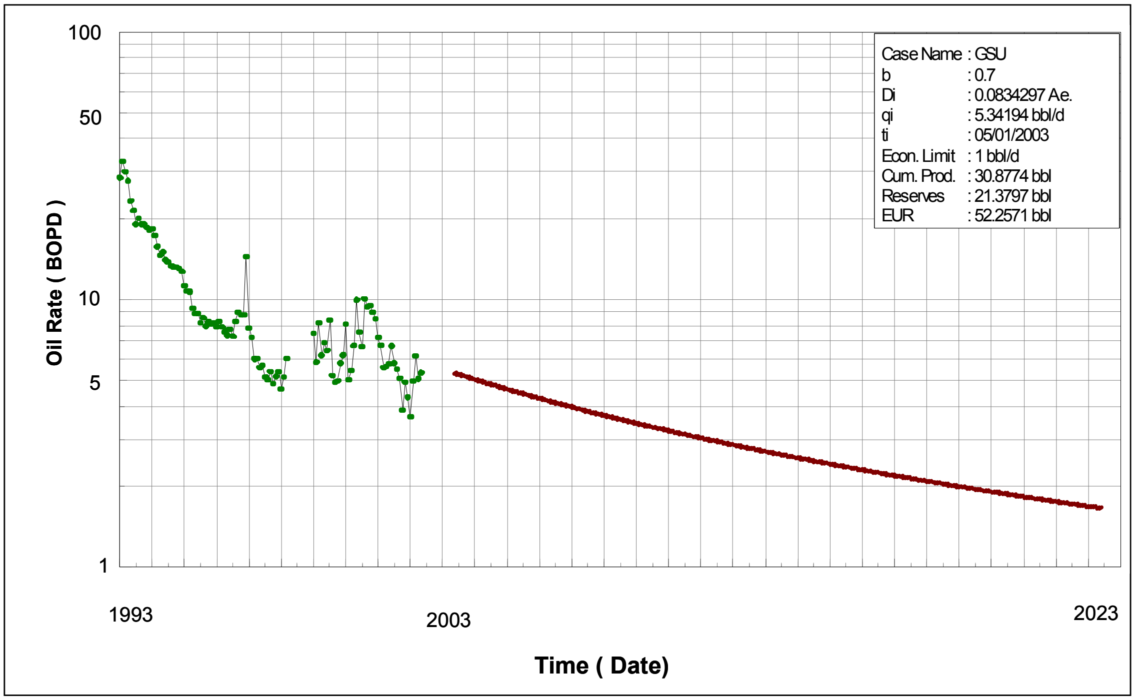

Fig. A. 10- Decline Curve Analysis for Well GSU-408

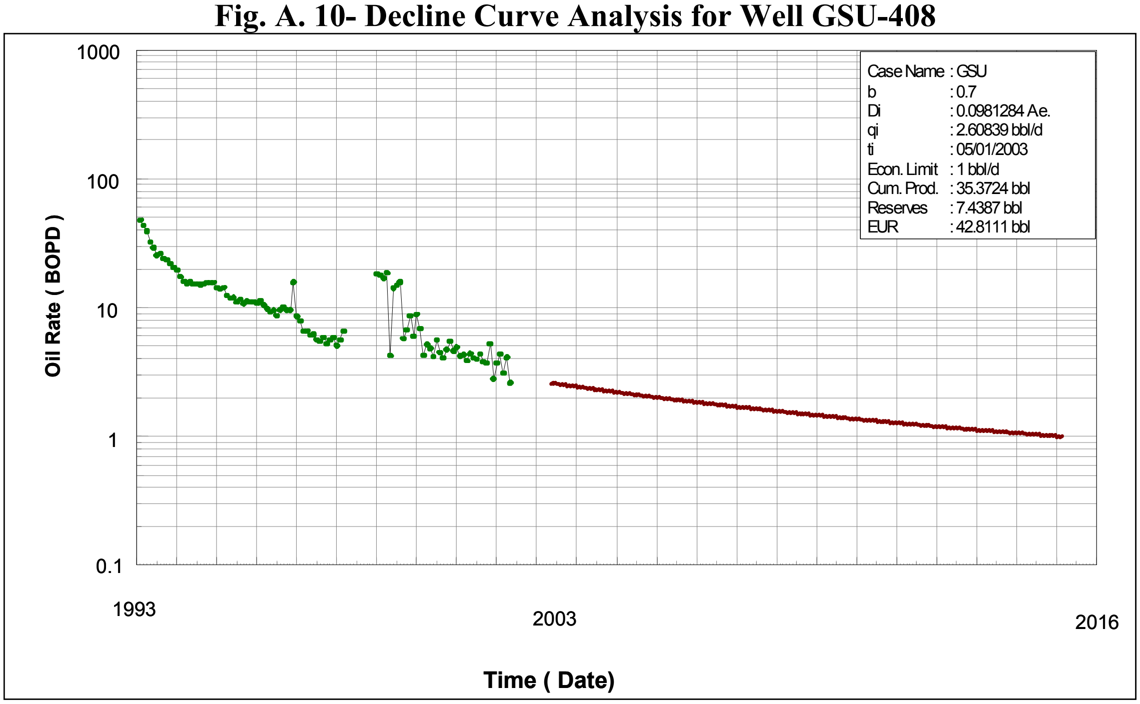

Fig. A.11 - Decline Curve Analysis for Well GSU-502

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

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