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FIELD VERIFICATION OF CO_2-FOAM

Annual Report

By
F. David Martin
John P. Heller
William W. Weiss

May 1991

Performed Under Contract No. DE-FG21-89MC26031

New Mexico Institute of Mining and Technology
New Mexico Petroleum Recovery Research Center
Socorro, New Mexico

Bartlesville Project Office
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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

ABSTRACT

The objectives of this project are to: 1) conduct reservoir studies, laboratory tests, simulation runs, and field tests to evaluate the use of foam for mobility control or fluid diversion in a New Mexico CO_2 flood, and 2) evaluate the concept of CO_2-foam in the field by using a reservoir where CO_2 flooding is ongoing, characterizing the reservoir, modeling the process, and verifying the effectiveness. Seven tasks were identified for the successful completion of this four-year project: 1) evaluate and select a field site, 2) develop an initial site-specific plan, 3) conduct laboratory CO_2-foam mobility tests, 4) perform reservoir simulations, 5) design the foam slug, 6) implement a field test, and 7) evaluate results. This report provides results of the first year of the four-year project.

By evaluating information from candidate CO_2 floods, a suitable field site in New Mexico, the East Vacuum Grayburg/San Andres Unit, has been identified as appropriate for the proposed work. The initial site-specific plan was developed and submitted for Unit Working Interest Owner approval in May 1990. Details of the proposed project were discussed with the Unit Working Interest Owners at a meeting in Odessa, Texas, on May 21, 1990. The operator of the Unit, Phillips Petroleum Company, submitted ballots for project approval. A sufficient number of Unit Working Interest Owners voted in favor of the project, and the project was approved on June 25, 1990. Therefore, Task 1 and most of Task 2 of the project have been completed. The first batch of representative reservoir cores have been received from Phillips Petroleum Company. The laboratory tests will begin as soon as this core material has been assessed, and after plugs have been cut and prepared. These tests will consist of both CO_2-foam mobility measurements, and surfactant adsorption tests. We will also seek some evaluation of the mineralogy and local heterogeneity in the cores.

A Joint Project Advisory Team was organized, and technical meetings to discuss additional details of the project were held in Odessa on August 2, 1990, and September 14, 1990. A suitable pattern in EVGSAU has been selected, and design considerations have been discussed. The advisory team agreed that an observation well in the pattern area would be desirable for providing cores and logs that will improve reservoir characterization as well as for monitoring foam performance. Reservoir simulation studies will begin during the next quarter.

INTRODUCTION

BACKGROUND

The use of CO_2 as a displacement fluid during enhanced recovery processes has increased in recent years, and work involving the selection of additives for use in CO_2 flooding has gained importance. This increase in the field application of CO_2 flooding has increased the need for the development of mobility control additives. Several organizations have been working on a process to improve the efficiency of CO_2 displacements that consists of the injection of a mixture of dense CO_2 with an aqueous solution of a suitable surfactant. This mixture generates lamellae or bubble films in the pore space of the rock which allow the mixture to move through the rock with a mobility that is significantly lower than that of CO_2 alone. The CO_2-foam that is generated can reduce the nonuniformities of the displacement front that are otherwise induced by flow through the heterogeneities of the rock. Thus, the use of CO_2-foam as a displacement fluid can give two benefits over the current use of CO_2 alone: it can reduce or suppress the formation of fingers caused by the instability of the displacement front, and it can reduce the severity of channels or preferential flow that would otherwise occur because of the heterogeneity of permeability.

For several years, laboratory work has been conducted at the Petroleum Recovery Research Center (PRRC), a division of New Mexico Institute of Mining and Technology (NMIMT), on the use of surfactants to generate foam for mobility control and fluid diversion in CO_2 floods. This work has been supported by the U.S. Department of Energy (DOE), the New Mexico Research and Development Institute (NMRDI), and a consortium of oil companies. The DOE expressed interest for a continuation of the ongoing research program to take the laboratory work to a field-testing stage, and Grant No.

DE-FG21-89MC26031 to the NMIMT was initiated on September 29, 1989. This grant provides for a four-year project conducted by the PRRC in collaboration with an oil producer actively involved in CO_2 flooding. The proposed work provides for an extension of the PRRC laboratory work to a field-verification stage.

OBJECTIVE

The objective of this project is to conduct reservoir studies, laboratory tests, simulation runs, and field tests to evaluate the use of foam for mobility control or fluid diversion in a CO_2 flood. The goal is to prove the concept of CO_2-foam in the field by characterizing the reservoir, modeling the process, and verifying the effectiveness and economics.

OUTLINE OF PROPOSED WORK

The seven tasks outlined in Table 1 have been proposed for the successful completion of this project. The project tasks include 1) Site Evaluation and Selection, 2) Develop Initial Site-Specific Plan, 3) Conduct CO_2-Foam Mobility Tests, 4) Reservoir Simulation, 5) Slug and Injectant Design, 6) Implementation, and 7) Evaluation. The schedule and timing for each of the tasks that were planned initially are shown in Table 2.

SUMMARY OF PROGRESS

TASK 1: SITE EVALUATION AND SELECTION

This task was completed during the first quarter of the project. Preliminary meetings were held with representatives from oil companies that had ongoing or planned CO_2 floods. Based on the results of the preliminary meetings, more detailed meetings were conducted with individuals from interested companies. These discussions included management, reservoir, research, and simulation personnel.

An industry liaison committee was established. For the purposes of site selection, the PRRC Industrial Advisory Board was consulted.

Criteria for site selection were established. The field test site should be representative of other CO_2 floods where mobility control may be a problem (similar in geology, depth, temperature, fluid properties, etc.).

Data available from potential field sites were analyzed. From a comparison of the data from the potential field sites and the selection criteria, two potential sites in New Mexico were identified. Based on input from the industry liaison committee, the most suitable site was selected. The field site selected for the CO_2-foam test is the East Vacuum Grayburg/San Andres Unit (EVGSAU) which is operated by Phillips Petroleum Company. Because the test site is located in the San Andres/Grayburg carbonate play, a transfer of the technology developed during this project to the larger group of similar reservoirs, illustrated in Figures 1 and 2, should prove quite useful to other producers.

TASK 2: DEVELOP SITE - SPECIFIC PLANS

Based on discussions with representatives from Phillips Petroleum Company in Odessa, TX, on December 12, 1989, a more detailed project schedule was prepared for the Initial Site-Specific Plan. The plan and an authorization for expenditure was then submitted to the EVGSAU interest owners for approval in May 1990.

Details of the proposed project were discussed with the Unit Working Interest Owners at a meeting in Odessa, Texas, on May 21, 1990. The operator of the Unit, Phillips Petroleum Company, submitted ballots for project approval. A sufficient number of Unit Working Interest Owners voted in favor of the project, and the project was approved on June 25, 1990.

A Joint Project Advisory Team (JPAT) was organized that includes technical representatives from the EVGSAU (Arco, Chevron, Exxon, Marathon, Mobil, Phillips, and Texaco) as well as representatives from the DOE and the PRRC. JPAT technical meetings to discuss additional details of the project were held in Odessa on August 2, 1990, and September 14, 1990. A suitable pattern in EVGSAU has been selected, based on the criterion that the production there be typical of other patterns without a remarkably better or worse record of CO_2 breakthrough than in the rest of the field. The location of the chosen pattern is shown in Figure 3, and design considerations have been discussed. The JPAT agreed that an observation well in the pattern area would be desirable for providing cores and logs that will improve reservoir characterization as well as for monitoring foam performance.

Phillips, as operator of the EVGSAU, will conduct all onsite operations pertaining to the drilling, completion, and operation of the well, and the well will be owned by the EVGSAU. This well will serve two primary purposes: 1) to further define the reservoir description in the pattern area through core acquisition/analyses, and 2) to observe fluid front movements associated with the foam injection. The following information portrays some of the initial thoughts regarding the need for an observation well within this pattern. At the upcoming November JPAT meeting, we plan to discuss this information in detail and will discuss the proposed coring and logging programs.

The observation well (3332-003) is proposed to be located approximately 150' to the west of the CO_2-foam injection well as shown in Figure 4. For reference, the offending CO_2 production well (3332-032) of this pattern is located to the southwest of the injection well. Approximately 450' of core is proposed to be cut through the San Andres interval. Of this total 450', an estimated 120' of sponge core will be cut.

The observation well will be openhole logged using the following suite of logs: Compensated Neutron, Litho Density (w/PE), Dual Laterolog, Micro SFL, and Borehole Compensated Sonic. In addition to the standard suite of logs, a Repeat Formation Tester to obtain pressure information on the various zones is recommended.

The observation well will be conventionally cased to approximately 4000'. In order to use the borehole as a logging monitor well, the bottom 800' (4000'-4800') will be cased with fiberglass. Recommendations for monitor well logging have not been finalized; however, our initial thoughts are to run the following logs: Dual Burst Thermal Decay Time Long (TDT-P), Dual Porosity Compensated Neutron Log (CNT-G), Phasor Induction Log (DIT-E), and Deep Propagating Electromagnetic Log (DPT).

The purpose of the monitor logging will be to observe changes in fluid saturations (water and CO_2) occurring within the various zones as a result of foam injection. In addition, the TDT-P could be used to detect the presence of the surfactant solution within a given zone if a suitable surfactant tagging agent can be found.

The observation well will be drilled and completed prior to beginning the baseline period. Contingent on rig availability, this well is scheduled for a late December 1990 spud date.

In light of the revisions to the original proposal and recommendations of the JPAT, the project schedule has been revised as shown in Table 3. While timing of the individual tasks has been changed, the project is scheduled for completion as originally planned.

TASK 3: CONDUCT CO_2-FOAM MOBILITY TESTS

The first batch of representative reservoir cores have been received by PRRC from Phillips Petroleum Company. The laboratory tests will begin as soon as this core material has been assessed, and after plugs have been cut and prepared. These tests will consist of both CO_2-foam mobility measurements, and surfactant adsorption tests. We will also seek some evaluation of the mineralogy and local heterogeneity in the cores.

The major laboratory research to be performed in this project is of three kinds. These are aimed at evaluation of CO_2-foam mobility in the chosen formation rock, the measurement of adsorption parameters of different surfactants on the internal pore surface of the rock, and the determination of surfactant solution and lamella characteristics at reservoir conditions of temperature, pressure and contact with dense CO_2. The principal goal of this work is to be able to select the surfactant to be used in the field tests, and the concentration at which it should be used. We also expect to assist in the examination of mineralogical and other properties of the formation rock. Inasmuch as definite site selection and transfer of core material from Phillips was only completed in the latter part of this first year of the project, much work remains to be done in our laboratory measurements. In each of the following sections, one of the major subtasks and its status is described.

Mobility Measurement

Our measurements of CO_2-foam mobility will utilize the same apparatus, and be performed following the same procedures, as have been described in several recent articles.[1-3] Briefly, this method consists of reservoir-pressure, steady-state measurement of the pressure gradient across short core samples during the simultaneous flow of dense CO_2 and surfactant solution through them. In our previous measurements of this quantity, we have varied the foam 'flowing quality' from 75 to 90%, and the combined Darcy velocity from about 2 ft/day to 14 ft/day. Because actual velocities decrease rapidly with distance from the injector, these rates will only be found relatively close to the well or in fractures or high permeability channels. For example, the Darcy rate of 2 ft/day can be expected to be found only 4.5 feet from the injection well, and the flow rate further out in the reservoir will be less than this by as much as two orders of magnitude. Unfortunately, ways of acquiring reliable data at such extremely low rates in the laboratory have not been developed. We have also utilized various surfactants and surfactant concentrations, and several different types of rock.

Perhaps our most important finding has been that one of the major factors determining CO_2-foam mobility is the type and permeability of the cores being tested. If mobility data from steady-state core tests are divided by the initial brine permeability at 100% water saturation, the reciprocal of the resulting relative mobility can be related to an apparent viscosity of the combined flow in the reservoir. This can also be expressed in terms of a dimensionless flow-resistance-effect of the foam compared to brine:

$$\text{Flow Resistance} = \frac{\lambda_{\text{brine at } 100\%\, S_w}}{\lambda_{\text{foam}}} = \frac{(k/\mu)\,\text{brine}}{(k/\mu)\,\text{foam}} = \frac{(q/\Delta p)_b}{(q/\Delta p)_f} = \frac{q_b \Delta p_f}{q_f \Delta p_b} \tag{1}$$

where the subscript "b" refers to brine flow conditions at 100% water saturation and the subscript "f" refers to foam flow conditions. If the foam test is conducted at the same rate as the initial brine permeability, the flow resistance effect is a ratio of the pressure drop during stabilized foam flow divided by the pressure drop during the single-phase brine flow. Figure 5 presents coreflood data in five different kinds of rock. As shown in Figure 5, the resistance to flow caused by CO_2-foam is affected greatly by the rock type and increases as rock permeability increases. This behavior is very desirable from the viewpoint that the foam is more effective in reducing mobility in higher permeability media and can mitigate some of the inherent reservoir heterogeneities.

For our planned experiments for this project, we will utilize several surfactants, concentrations and flow rates, with dolomitic core material from the San Andres formation in the EVGSAU. We are also planning to modify our laboratory procedures somewhat, to allow computerized data acquisition.

With the arrival of five pieces of core (three-quarter slabs, averaging 5 inches long) from the Bartlesville laboratory of Phillips Petroleum Company in early September, it has become possible to start these experiments. Several core samples have already been cut, and are presently being mounted for use in our standard coreholders.

Adsorption Measurement

The wrong choice of surfactant could be quite serious, as it might result in excessive reactions between the surfactant and the reservoir rock surfaces, resulting in a large amount of surfactant being lost to the formation by way of adsorption. This could be a major expense of the project and place CO_2-foam floods beyond the limit of profitable EOR operations. It is thus quite important to measure surfactant adsorption under conditions similar to those in the field. For this purpose, a dynamic method is to be used, to acquire information on both the total adsorption, as well as the irreversible surfactant adsorbed. The first of these is measured by the chromatographic delay in the arrival of a 'slug' of surfactant, and the second by the quantity of surfactant that remains in the core sample after passage of the slug.

During the latter part of this first year, we have developed a method for the measurement of low output surfactant concentrations that we feel will be particularly suitable for making an accurate assessment of adsorption. Our method consists of the continuous measurement of the surface tension of the brine emerging from the core, using an automated drop-weight method. A major experimental problem with this method was the short-term variability of commercial constant-rate pumps. This has recently been solved by the use of a low-volume laboratory-built pulse dampener. The method is most accurate when used for surfactant solutions at low concentrations, which is the concentration region where the flood will probably be operated to avoid large losses in injectivity in the reservoir.

High-Pressure Surfactant Assessment

A third laboratory activity consists of the measurement of interfacial tension (IFT), and the observation of lamella stability, when field brines containing surfactant are in contact with reservoircondition dense CO_2. The preliminary list of possible surfactants—Witcolate 1238, Chevron CD 1040 and Chevron 1050—have already been examined in our 'Foam Durability Apparatus' against a lower salt content brine. The device consists of a transparent high pressure cell initially charged with the surfactant solution being tested. The pressure cell is enclosed in a water bath, which can be elevated to EVGSAU reservoir temperature (40°C). The pressure in the aqueous contents of the cell is raised to reservoir pressure by means of a liquid-filled Ruska pump, and the pressure of dense CO_2 in a steel cylinder (also submerged in the water bath) is adjusted to the same value.

Surfactant solution is then slowly withdrawn into a tank connected to the Ruska pump, enabling CO_2 at no appreciable change of pressure to bubble into the visual cell. From the rate of bubbling, the IFT can be calculated. The bubbles accumulate in the top of the high-pressure visual cell, forming a foam. After a standard amount of surfactant has been withdrawn, the quantity and stability of the remaining foam can be measured.

Although no quantitative standards have been set, there appears to be some agreement that the ideal foamant for use in the CO_2-foam process should be neither too stable nor too unstable. Too low a stability, as indicated by little or no foam being produced in our apparatus by the accumulating bubbles, would probably indicate an ineffective surfactant. Too high a stability, as indicated by long persistence of the foam, would probably indicate that the mobility reduction would be excessive, especially at low flow rates where one would expect lamellae to break and permit flow under these conditions.

Petrologic Observations

The dolomitic core material sent by Phillips is well consolidated and rich in deposited anhydrite. As a secondary activity, we are undertaking the use of a minipermeameter to measure the correlation length and overall variance of permeability values along the slab surface of one of the cores.

Another interesting feature of one of the cores is a stylolite extending across it. We have cut a portion from the core across this feature and another research group at PRRC will prepare thin sections and perform a petrographic study. This may contribute to discussions taking place with some of the Phillips personnel, concerning the influence of the stylolites and of the stylolitic deposits on the flow.

Summary

We expect that in the next several months we shall be well along on the laboratory tasks described.

TASK 4: RESERVOIR SIMULATION STUDIES

The East Vacuum Grayburg/San Andres Unit Field Verification of CO_2-Foam simulation studies will be divided into five distinct categories: 1) history match, 2) model development, 3) model calibration, 4) predictions of field performance/pilot design, and 5) analysis of pilot data. Researchers at the PRRC will continue to refine the mechanistic foam flood simulator that was recently developed. Incorporation of the mechanistic model into the pattern-scale simulation studies will be supervised by Dr. John Killough at the University of Houston, under a subcontract to PRRC.

History Match

The history match component will consume a considerable portion of the effort in the first year. VIP-COMP of Western Atlas Integrated Technologies will be used for the bulk of the work. This commercial, n-component, EOS compositional simulator provides many features which will be necessary for the East Vacuum study. Most of these additional features are not available in public domain or university-developed software. With availability of the source code to the University of Houston, significant modifications can also be made to this model as the need arises. The first step in the history match will be to develop an EOS match of the PVT data. Although Phillips has done this to some extent, their EOS may be slightly different from that in the VIP model. We will attempt to match the history of the chosen pilot area using a locally refined grid for the pilot pattern inside of a coarse grid multiple pattern simulation. This grid configuration will hopefully account for non-confined pattern boundary fluxes, and allow a history match which is closer to reality.

Model Development

The model development phase will consist primarily of addition of a CO_2-foam mechanism to the VIP-COMP model. The mechanism will first be added in an IMPES sense and then as fully-implicit. The mechanism will be similar to that used by PRRC in previous simulation work[4] with modifications for the particular surfactant to be used in this study. The implicit model development will be necessary to study the near well effects of foam generation or instability. These single studies require small cells near the wellbore and hence must be treated in a fully-implicit fashion.

Model Calibration

The model calibration phase will consist of validating the CO_2-foam mechanism through comparison with laboratory data. Scale-up from fine to coarse grids will be included by simulating pattern floods using curvilinear grids with fine gridding near the producer and injector. The foam mechanism will then be modified for the coarse grid study so that the coarse grid model will reflect the fine grid results. These can be thought of as pseudo functions for the foam flow mechanism.

Predictions of Field Performance/Pilot Design

The prediction of performance step will consist of combining the results of the first three steps into a single model. Several possible scenarios will be simulated to optimize the pilot for a compromise between best data to obtain the best oil recovery for the study.

Analysis of Pilot Data

The analysis phase will consist of recalibration of the predictive model after production from the foam pilot has begun. This phase may allow a change in pilot design to further improve oil recovery and/or data gathering.

TASK 5: SLUG AND INJECTANT DESIGN

Information resulting from the performance of Tasks 3 and 4 will be used to design the foam slug. Slug size and surfactant concentration will depend on mobility, retention, and dispersion characteristics of foam under field conditions.

TASK 6: IMPLEMENTATION

The baseline period prior to foam injection will attempt to mimic the proposed foam injection period in flow rates and scheduling. This will be done to have a control data period for comparison to the actual foam cycle data. Setting the exact injection scheme is not possible because there are numerous unknowns about how the foam cycle will be conducted, i.e., adsorption levels, foam quality, foam slug size, etc.

The injection scenario will continue to honor the 1-2 water-alternating-gas (WAG) cycle, but to achieve optimum foam generation, the following general outline will be used:

1. Prepad with surfactant (for adsorption).

2. 0.25 to 1.0 surfactant-alternating-gas (SAG) ratios for 4 week period.

An observation well will be used for two general purposes:

1. To obtain new core from the pattern area for better reservoir characterization which is essential for the reservoir simulation efforts.

2. To monitor the surfactant and/or changes in fluid saturations during the project for the assessment of mobility control.

The collection of pre-foam baseline data will be important for the subsequent evaluation of performance of the CO_2-foam test. These data will include well injectivity, injection profiles, CO_2 breakthrough in producers, pressure transient tests, and interwell tracers.

Detailed historical baseline data will be obtained for the pattern prior to startup of the test. Following this, a CO_2-water cycle identical to that to be used while injecting surfactant will begin in the pattern in order to develop a good baseline prior to beginning the foam test. During this period, field testing work will be conducted. Baseline tests under consideration include the following:

- Wellhead injection pressure and rate monitoring for both the test injection well and the adjacent injection wells
- Producing wellhead pressure, bottomhole pressure, and rate monitoring
- Injection well falloff testing
- Produced gas analyses
- Water salinity, pH, and background surfactant concentration in the producers
- Injection well profile testing
- Interwell tracers
- Injectant tagging and monitoring program
- Surfactant Pump-In/Pump-Out testing

A pump-in/pump-out test with tracers and surfactant solution may be useful in substantiating the surfactant adsorption numbers obtained from the laboratory experiments. After the baseline data has been collected, a cycle containing the chosen surfactant will commence. The field testing work will be repeated and evaluated against the baseline data.

Pressure transient tests will be used to establish pre-foam mobility. Benchmark measurements of both water and CO_2 in-situ mobilities will be made since the selected pilot is in a water-alternating-gas (WAG) project. These tests will also assess wellbore damage. As an example, results of pressure falloff tests performed in a nearby CO_2 flood are presented in Figure 6. These tests were performed in a San Andres injection well prior to CO_2 injection and during CO_2 injection. An interpretation of the test conducted during CO_2 injection suggests that water does reduce mobility. However, the analysis is clouded by the results of a test performed on the same well during waterflood operations prior to the CO_2 flood. The results of the tests are presented in semilog and logarithmic formats. After injecting CO_2 for 15 months, the 1990 test data were collected following the injection of 10,000 bbl of water to kill the well in preparation for a workover. The anomaly in the slope is interpreted as a change in mobility since a similar change (boundary effect, dual porosity) is not evident during the water injection test prior to the CO_2 flood. There is some chance that the anomaly is due to a layered system since additional perforations were added prior to the CO_2 flood. Utilizing an interpretation method presented by Merrill[5], the transmissibility in the CO_2 zone is 854 $\frac{md\text{-}ft}{cp}$ while the transmissibility in the water zone 432 $\frac{md\text{-}ft}{cp}$. Analysis of the waterflood water falloff test during the same dt period results in a transmissibility of 143 $\frac{md\text{-}ft}{cp}$ (30% of the above) which clouds the analysis. The use of radioactive tracers in both the water and CO_2 will further define the pattern area.

TASK 7: EVALUATION

For the short term, the injectivity index of the foam injection well will be a key process performance indicator. A reduction in the injectivity index could indicate either reduced fluid mobility or wellbore damage. A pressure transient test is necessary to separate skin effect from mobility reduction.

Changes in fluid entry profiles could indicate either fluid diversion at the wellbore or wellbore damage. If travel time between injector and producer is short (less than a week), then a rapid change in the produced gas/oil ratio (GOR) can be used to confirm fluid diversion. Pilot area production history since unitization is shown in Figure 7. While the small surfactant slug sizes are not intended to demonstrate additional oil production, favorable changes in fluid diversion of CO_2 or mobility control after the foam injection may be observed by decreases in gas production or GOR in the offending wells.

Over the long term, process performance can be determined by changes in the baseline measurements. However, short-term changes in the pressure and rate history of the injection well are the key to evaluating process performance. Mobility changes detected by injectivity index changes, transient test results, and fluid entry surveys will be compared to changes predicted in Tasks 3 and 4. These are the readily available short-term diagnostic tools. The benchmark measurements can be compared to those predicted with the fully-compositional reservoir foam simulator.

Surfactant concentration of the foam slug and slug size may be modified based on short-term field observations. Performance will be continuously compared to the predicted performance.

In addition to the logging measurements at the observation well, foam propagation can be followed with a series of pressure transient tests. It is anticipated that pressure-time plots of the transient data will reflect the change in mobility with a slope change. The distance to the foam front can calculated from the inflection point of the pressure-time plot. The distance should approximate that determined by a material balance calculation which includes surfactant retention.

The short-term assessment of mobility control versus fluid diversion will be based on response time of produced GOR's. It is believed that a reduction in GOR due to mobility control will occur over a long time period, and this would be supported by transient pressure test history. GOR changes due to fluid diversion occur rapidly and can be supported by fluid entry profiles at the injection well.

Overall sweep efficiency can be estimated by simulation. Correlations can be used to estimate areal sweep efficiency if mobility is known and the reservoir is homogeneous.

An economic evaluation will be accomplished with the computer model developed to simulate the reservoir. Foam parameters confirmed with field results will be varied to simulate various application scenarios, and the economics of these scenarios will then be evaluated.

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Table 1
Planned Project Tasks
Field Verification of CO_2-Foam

Task		
1	Site Evaluation and Selection	
	1.1	Preliminary Meetings with Oil Company Representatives
	1.2	Follow-up Detailed Meetings with Interested Companies
	1.3	Establish Industry Liaison Committee
	1.4	Establish Criteria for Site Selection
	1.5	Analysis of Available Site Data
	1.6	Select Site
2	Develop Initial Site-Specific Plan	
	2.1	Execute Agreement Between Oil Company and PRRC
	2.2	Establish Joint Project Team
	2.3	Analyze Existing Reservoir Data
	2.4	Conduct Baseline Reservoir Characterization
	2.5	Prepare Recommendations for Additional Reservoir Characterization
	2.6	Finalize Reservoir Characterization
	2.7	Prepare Initial Plan
	2.8	Obtain Company, State, and DOE Approval
3	Conduct CO_2-Foam Mobility Tests	
	3.1	Measure Mobility of CO_2-Foam in Reservoir Rocks
	3.2	Measure Surfactant Properties
	3.3	Measure Surfactant Adsorption on Reservoir Rock
	3.4	Observe Emulsification Behavior of Surfactant/Oil
	3.5	Determine Optimum Surfactant and Surfactant Concentration
	3.6	Evaluate Effect of Oil Saturation on Mobility and Propagation of Foam
4	Reservoir Simulation	
	4.1	Measure Properties of CO_2/Reservoir Fluids
	4.2	Conduct Micromodel and Corefloods with Reservoir Rock
	4.3	Develop Correlations Describing Mechanisms for CO_2-Foam
	4.4	Predict CO_2 Flood Performance with Commercial Reservoir Simulator
	4.5	Couple Foam Flood Simulator with Reservoir Simulator
	4.6	Predict Performance of CO_2-Foam
5	Slug and Injectant Design	
	5.1	Revise Initial Plan
	5.2	Specify Type of Field Test
	5.3	Determine Design of Foam Slug
6	Implementation	
	6.1	Establish Pre-Foam CO_2 Mobility
	6.2	Project Start-up
	6.3	Monitoring
7	Evaluation	
	7.1	Process Performance
	7.2	Comparison to Prediction
	7.3	Modification Based on Response
	7.4	Assess Foam Propagation
	7.5	Assess Mobility Control/Fluid Diversion/Sweep Efficiency
	7.6	Economic Evaluation

Table 2
Planned Project Schedule
Field Verification of CO_2-Foam

Task No.	Task Description	Schedule
1	Site Evaluation and Selection	9/30/89 to 12/30/89
2	Develop Initial Site-Specific Plan	12/30/89 to 3/30/90
3	Conduct CO_2-Foam Mobility Tests	12/30/89 to 12/30/90
4	Reservoir Simulation	3/30/90 to 3/30/93
5	Slug and Injectant Design	3/30/91 to 9/30/91
6	Implementation	3/30/90 to 9/30/93
7	Evaluation	9/30/91 to 9/30/93

Time/Task Chart

Task No.

1 Site Evaluation and Selection

2 Develop Initial Site-Specific Plan

3 Conduct CO_2-Foam Mobility Tests

4 Reservoir Simulation

5 Slug and Injectant Design

6 Implementation

7 Evaluation

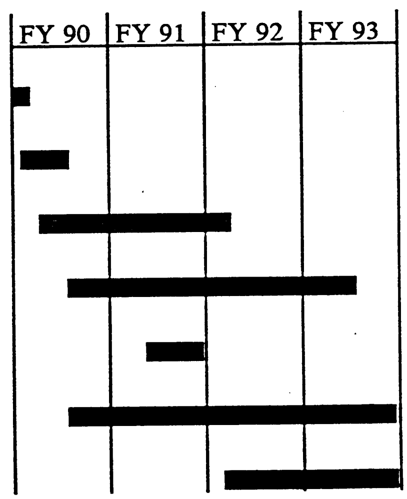


Table 3
Revised Project Schedule
Field Verification of CO_2-Foam

Task No.	Task Description	Schedule
1	Site Evaluation and Selection	9/30/89 to 12/30/89
2	Develop Initial Site-Specific Plan	12/30/89 to 9/30/90
3	Conduct CO_2-Foam Mobility Tests	9/30/90 to 12/31/91
4	Reservoir Simulation	10/31/90 to 6/30/93
5	Slug and Injectant Design	3/30/91 to 9/30/91
6	Implementation	6/30/90 to 9/30/93
7	Evaluation	9/30/91 to 9/30/93

Time/Task Chart

Task No.

1 Site Evaluation and Selection

2 Develop Initial Site-Specific Plan

3 Conduct CO_2-Foam Mobility Tests

4 Reservoir Simulation

5 Slug and Injectant Design

6 Implementation

7 Evaluation

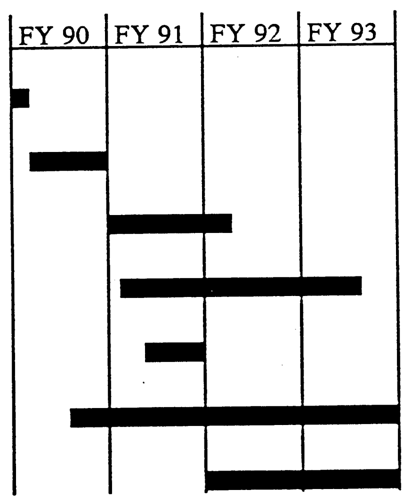


Table 4
Goals and Milestones for Reservoir Simulation Studies
Field Verification of CO_2-Foam

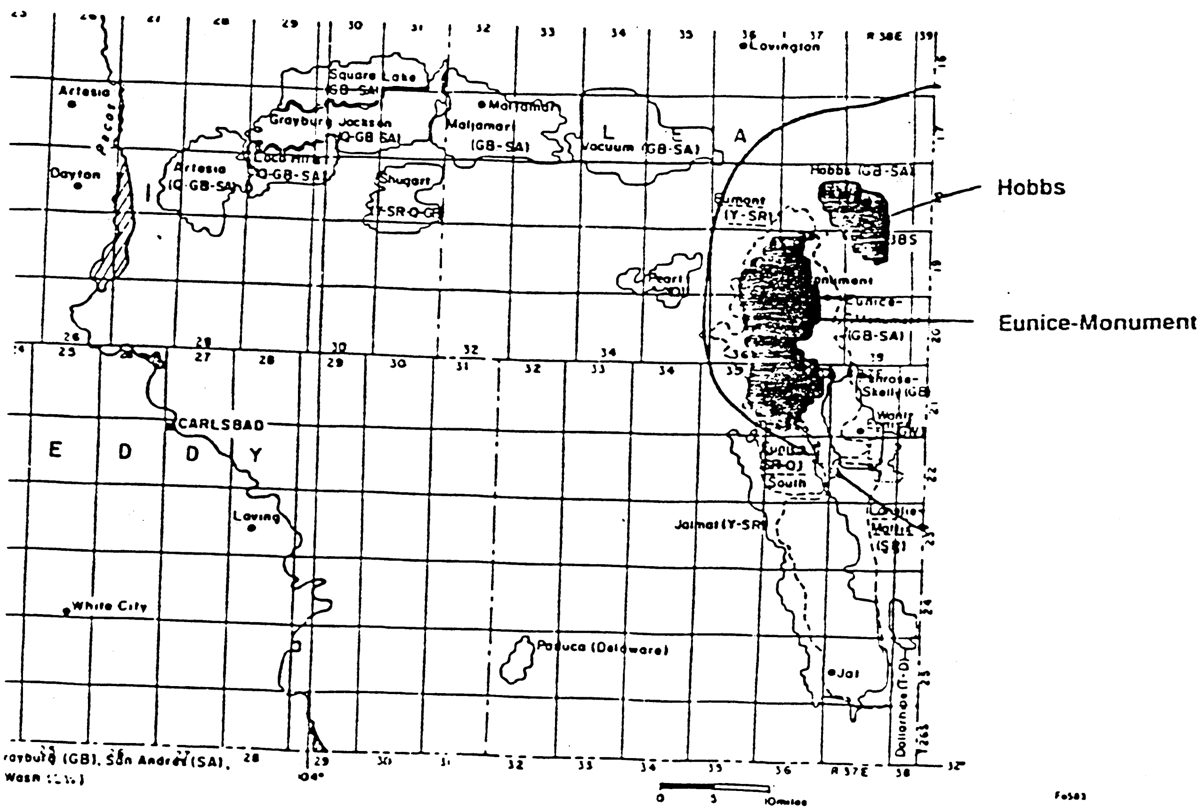
Phase I (Year 1):

1.	History Match		9/90 - 9/91
2.	Model Development		
	a.	IMPES	9/90 - 12/90
	b.	Implicit	12/90 - 6/91
3.	Model Calibration		6/91 - 10/91

Phase II (Years 2-4):

1.	Model Calibration (Continued)	11/91 - 2/92
2.	Predictions of Performance	3/92 - 9/92
3.	Analysis/Recalibration	9/92 - 6/93
4.	Final Report	6/93 - 7/93

Major New Mexico Reservoirs in the San Andres/Grayburg Carbonate (NCBP) Play



Source: N.M. Bureau of Mines & Mineral Resources, 1978

Figure 1. San Andres/Grayburg Reservoirs in Southeast New Mexico.

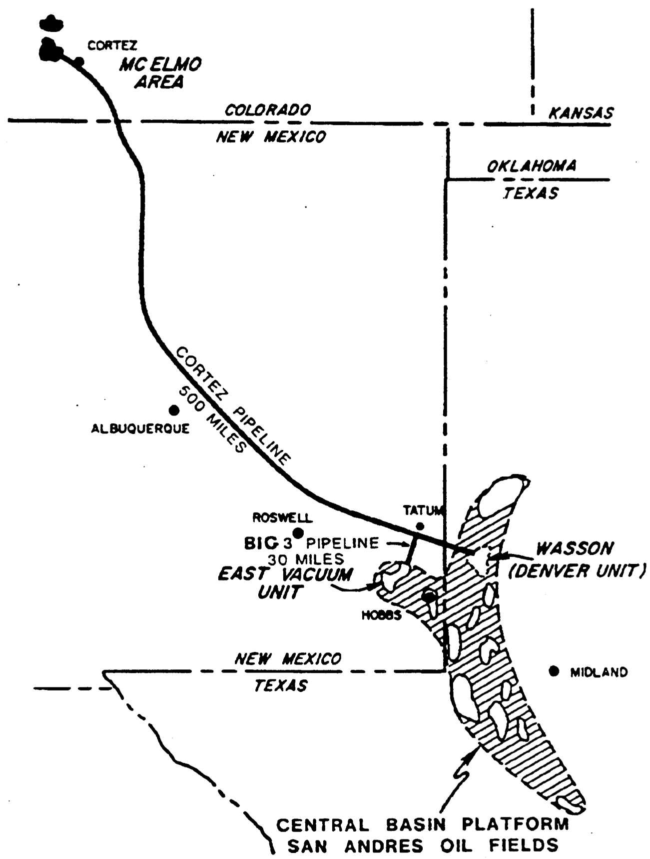


Figure 2. CO_2 Supply Route.

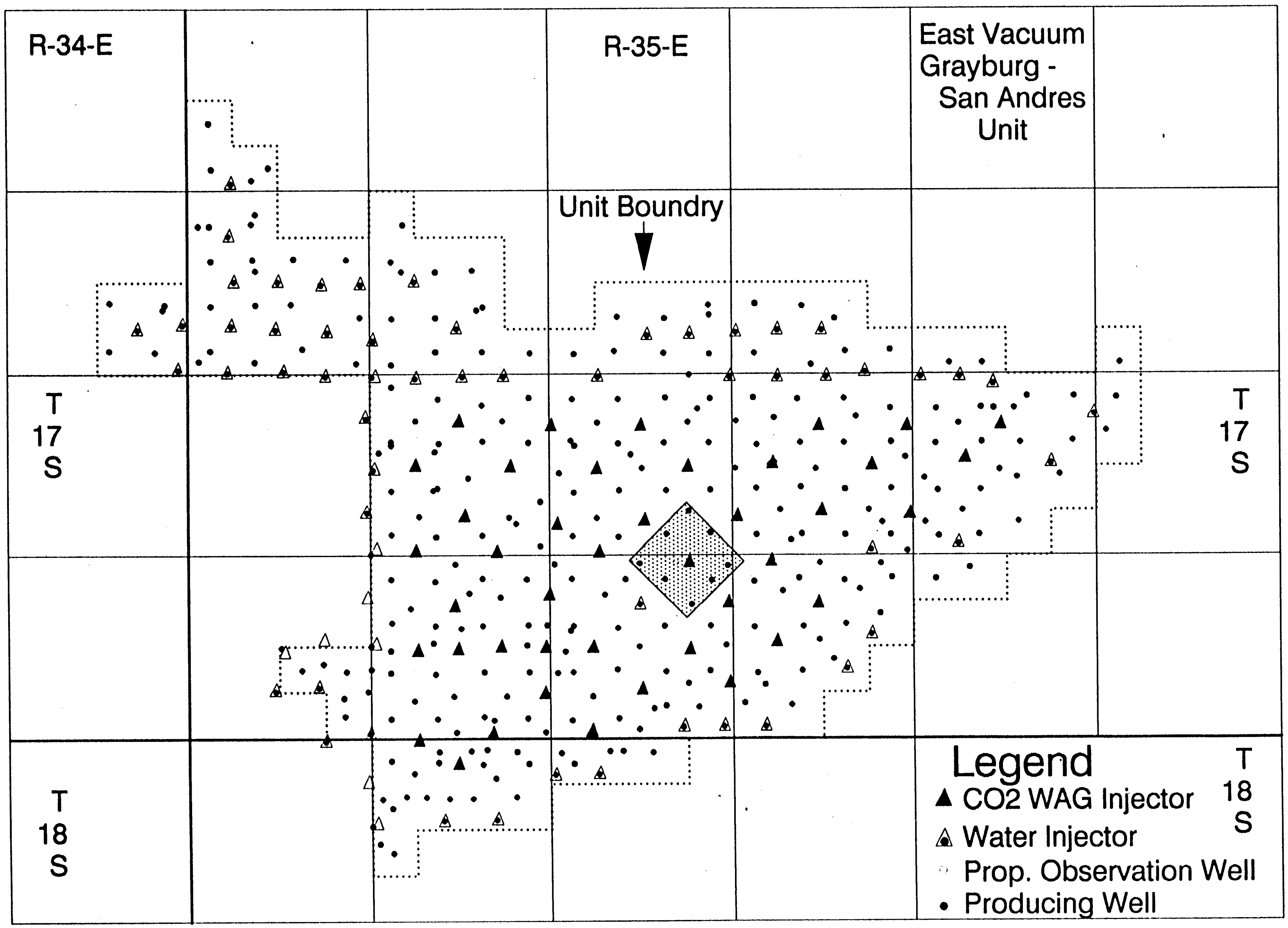


Figure 3. Location of Proposed CO_2–Foam Test in EVGSAU.

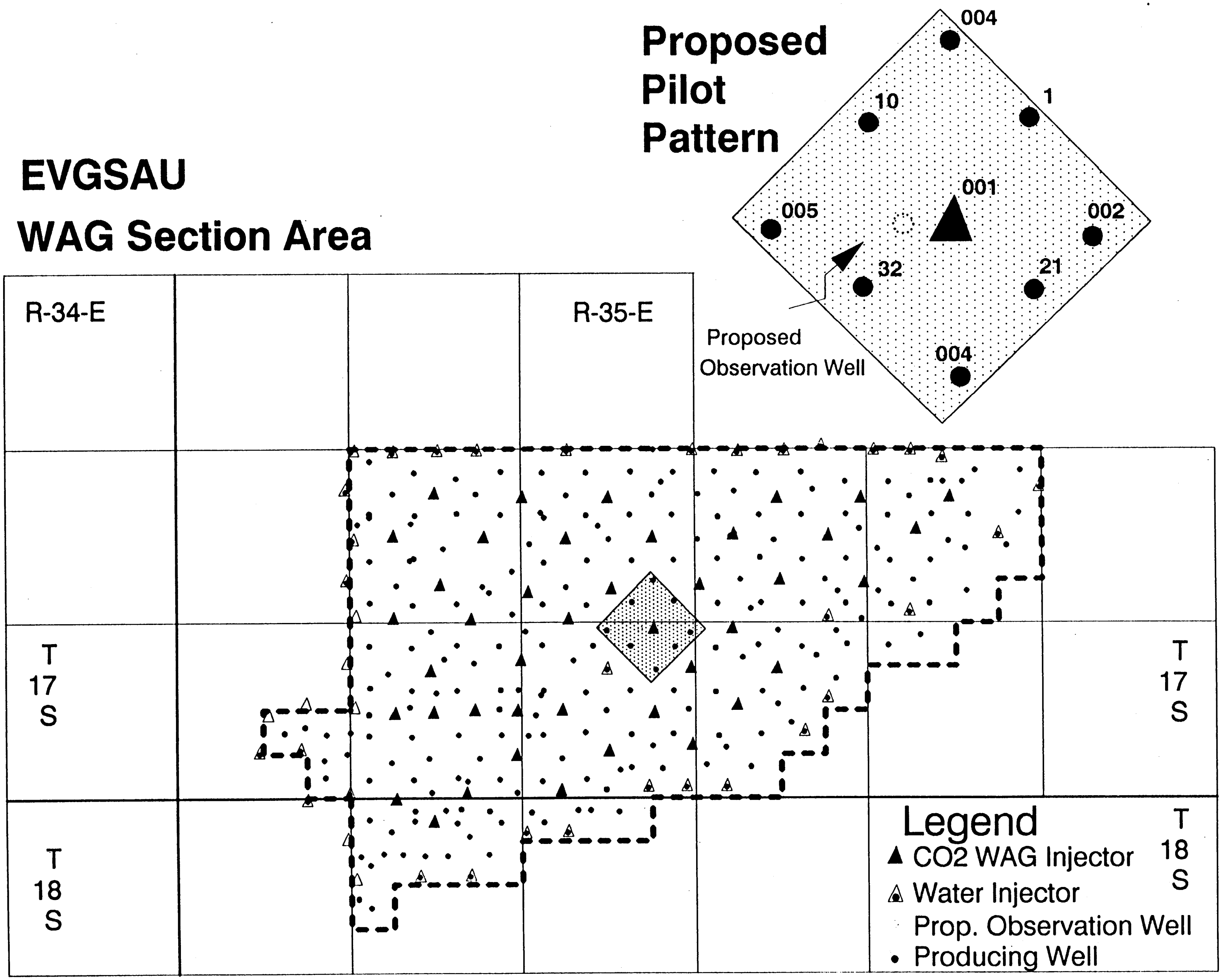


Figure 4. Pattern Selected for CO_2–Foam Test.

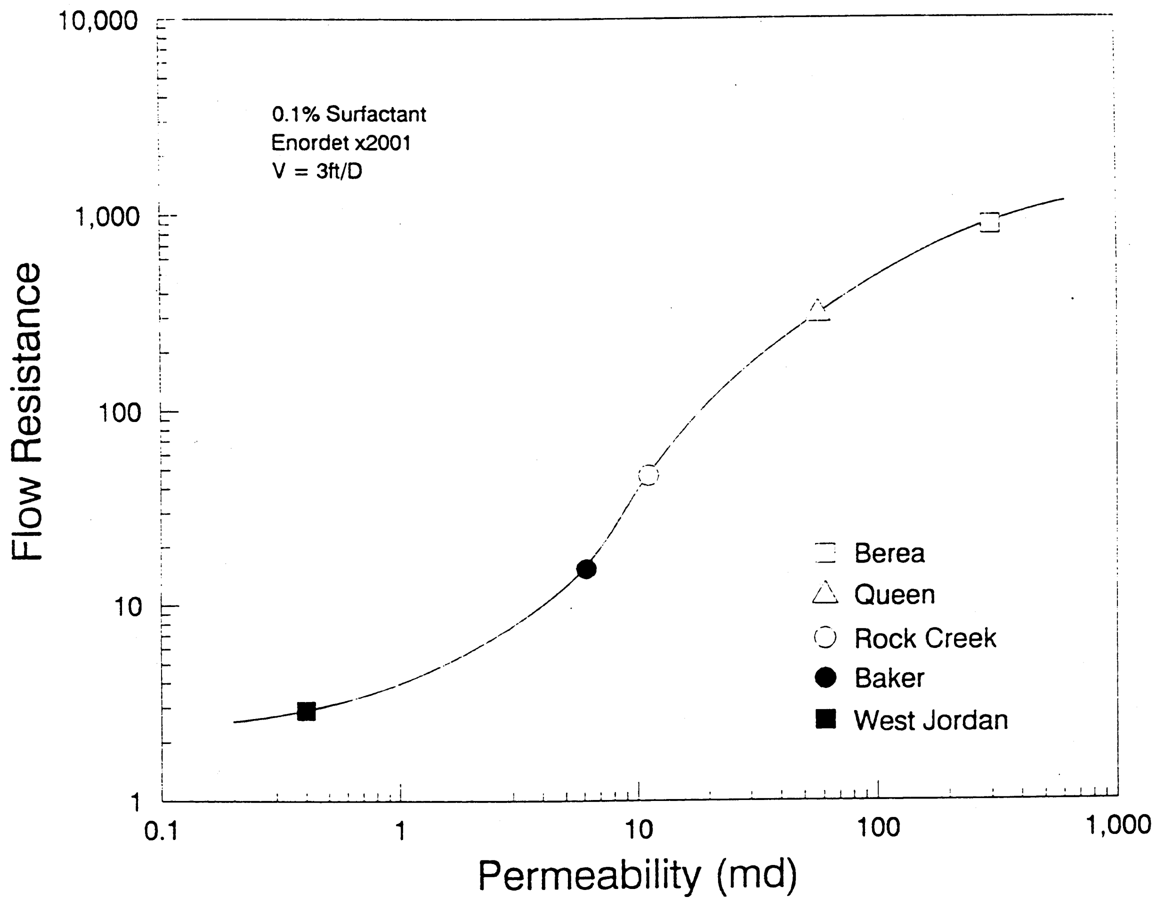


Figure 5. Flow Resistance vs. Permeability

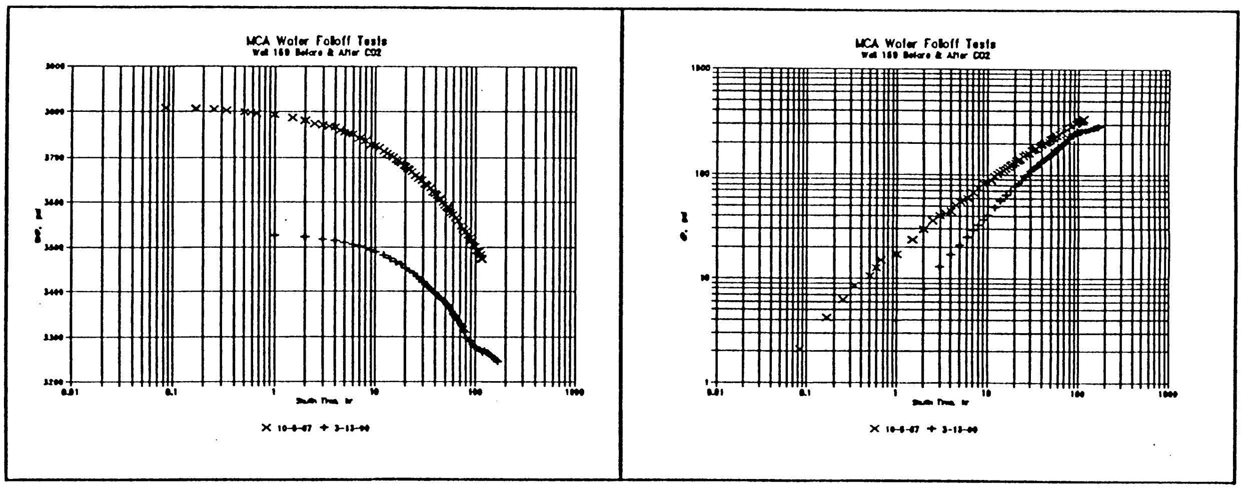


Figure 6. Example Pressure Falloff Tests.

EVGSAU
CO_2 Foam Pilot

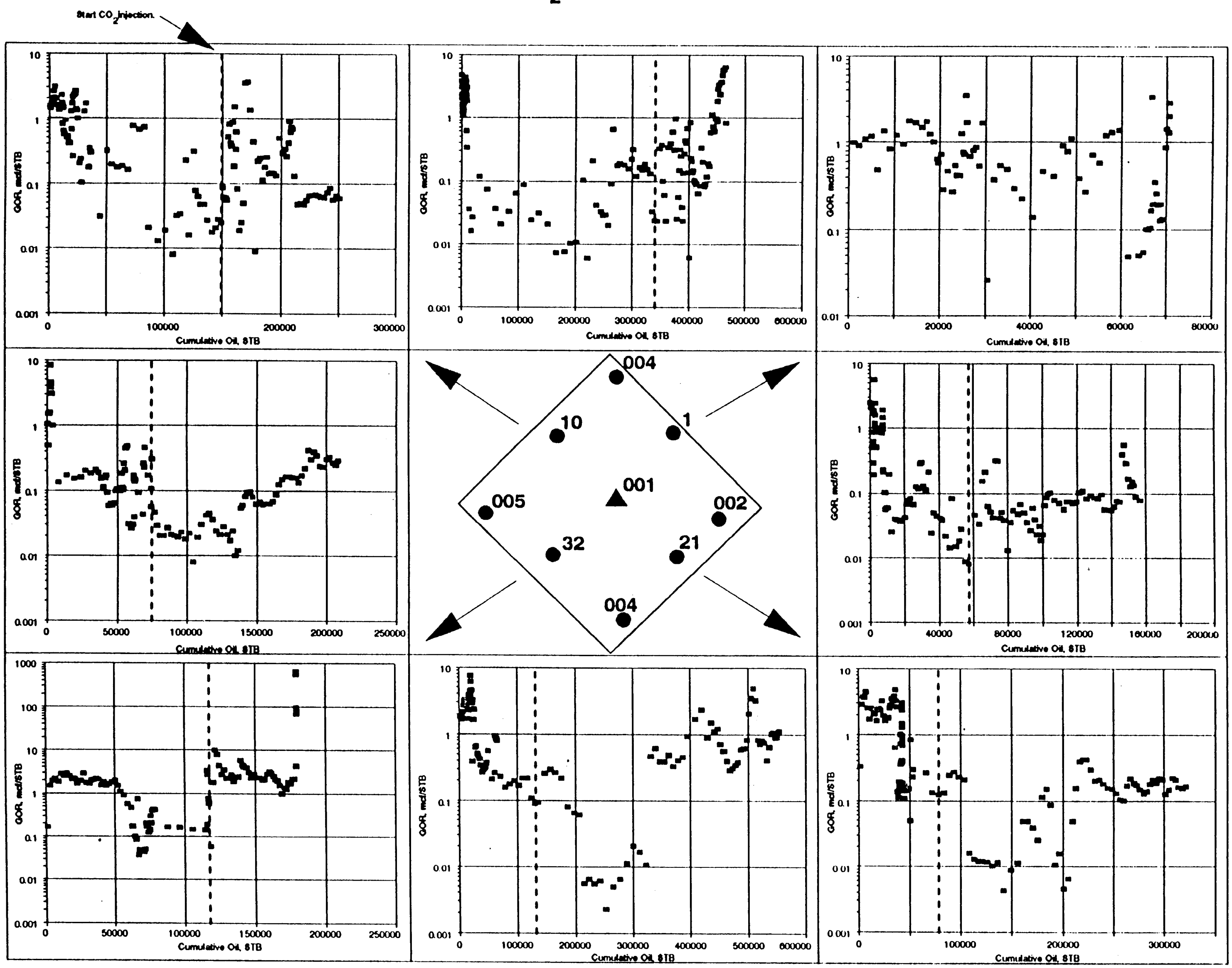


Figure 7. Pilot Area Production History Since Unitization.