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FIELD VERIFICATION OF CO_2-FOAM

Second Annual Report
October 1, 1990 - September 30, 1991

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

May 1992

Performed Under Contract No. DE-FG21-89MC26031

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

Bartlesville Project Office
U. S. DEPARTMENT OF ENERGY
Bartlesville, Oklahoma

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Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

Royal J. Watts, Project Manager
Morgantown Energy Technology Center
P. O. Box 880
Morgantown, WV 26505

Prepared by
New Mexico Institute of Mining and Technology
Petroleum Recovery Research Center
Socorro, NM 87801

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ABSTRACT

In September 1989, the Petroleum Recovery Research Center (PRRC), a division of New Mexico Institute of Mining and Technology, received a grant from the U.S. Department of Energy (DOE) for a project entitled "Field Verification of CO_2 Foam." The grant provided for an extension of the PRRC laboratory work to a field testing stage to be performed in collaboration with an oil producer actively conducting a CO_2 flood. 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 monitoring performance of the field test. Seven tasks were identified for the successful completion of the 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.

By evaluating information from candidate CO_2 floods, a suitable field site in New Mexico, the East Vacuum Grayburg/San Andres Unit (EVGSAU), operated by Phillips Petroleum Company, was identified by PRRC as appropriate for the proposed work. The four-year project is jointly funded by the EVGSAU Working Interest Owners (WIO), the U.S. Department of Energy (DOE), and the State of New Mexico. The PRRC is providing laboratory and research support for the project. A Joint Project Advisory Team (JPAT) composed of technical representatives from several WIO companies provides input, review, and guidance for the project. This report is the second annual report for this project.

A suitable pattern in the EVGSAU was selected, based on the criterion that the production there be typical of other patterns without a distinctly better or worse record of CO_2 breakthrough

than in the rest of the field. An observation well was drilled in the pattern approximately 150 ft from the pattern injection well. The observation well was cored and logged to improve reservoir characterization in the pattern area, as well as to provide reservoir cores for laboratory tests with suitable foam-generating surfactants. In order to use the borehole as a logging monitor well, the bottom 800 ft was cased with fiberglass.

A geological characterization of the pilot area and surrounding patterns has been assembled for the history matching and reservoir simulation studies that are in progress. The foam-flood mechanistic model developed at the PRRC is being incorporated into the field-scale reservoir simulator.

This report summarizes the project plans, the baseline field testing, and the laboratory test results that pertain to surfactant selection. A commercial surfactant was approved for the field test by the JPAT representatives. The baseline testing is in progress, and surfactant injection is scheduled to commence in the first quarter of 1992. Following three months of a pre-foam surfactant pad to satisfy the adsorption of the reservoir, a rapid cycle of surfactant alternated with CO_2 will be injected to generate an 80% quality foam.

INTRODUCTION

BACKGROUND

The use of CO_2 as a displacement fluid during enhanced recovery processes has increased in recent years,[1] and work involving the selection and development of mobility control additives for use in CO_2 flooding has gained importance. Several organizations have been working on processes to improve the efficiency of CO_2 displacements that consist of the injection of a mixture of dense CO_2 with an aqueous solution of a suitable surfactant. This mixture generates lamellae (bubble films) in the pore space of the rock, which allows 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 also 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 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 heterogeneity of the reservoir rock.

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 increasing the efficiency of 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 research program and provided a grant to the NMIMT in September 1989 to take the laboratory work to a field-testing stage. The grant provides for an extension of the PRRC laboratory work to a field-verification stage to be conducted by the PRRC in collaboration with an oil producer actively involved in CO_2 flooding.

OBJECTIVES

The objectives of this four-year 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.

OUTLINE OF PROJECT TASKS

Seven tasks were identified for the successful completion of this project. The project tasks include 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.

SUMMARY OF PROGRESS IN THE FIRST YEAR OF THE PROJECT

By evaluating information from candidate CO_2 floods, a suitable field site in New Mexico, the East Vacuum Grayburg/San Andres Unit (EVGSAU), operated by Phillips Petroleum Company (PPCo), was identified by the PRRC as appropriate for the proposed work. During the first year of this project, representatives from the PRRC and PPCo prepared an initial site-specific plan for the proposed work at the EVGSAU. The plan was approved by the EVGSAU Working Interest Owners (WIO) in June 1990. A Joint Project Advisory Team (JPAT) was organized that represents several of the EVGSAU WIO companies. This group serves as a technical steering committee that acts in an advisory capacity. Any recommendations for changes in the project design or scope are presented to the WIO members for consideration and approval. The JPAT has held several technical meetings

to discuss additional details of the project. A suitable pattern in EVGSAU was selected for the field tests and design considerations were evaluated. 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. An observation well was drilled, logged, and cored. Representative slabbed cores were selected by PPCo and sent to the PRRC for laboratory testing. The primary goal of the laboratory work was to select a suitable foam-generating surfactant for the EVGSAU field test. A secondary goal was to gain insight into the heterogeneous structure of the reservoir by examination of these cores.

DISCUSSION

The laboratory testing and reservoir simulation studies were started in early 1991. This report presents a summary of the results obtained during the second year of the project, with particular emphasis on the laboratory tests performed by the PRRC and PPCo to select the surfactant for the planned field test.

SITE EVALUATION

Field Development and History

The EVGSAU, located about 15 miles northwest of Hobbs in Lea County, is the site of the first full-scale miscible carbon dioxide injection project in the state of New Mexico. Field development and initial results of the CO_2 flood at the EVGSAU have been described previously.[2] Reservoir parameters for the EVGSAU are included in Table 1. The major productive interval at the EVGSAU is the San Andres Zone, a low permeability dolomite, which is similar to other San Andres reservoirs in the vicinity. The 5000-acre CO_2 flood is divided into three water-alternating-gas

(WAG) areas where CO_2 injection was initiated in September of 1985. A 2:1 WAG ratio was chosen so that while CO_2 is injected into one area, water is injected into the other two areas of approximately equal pore volumes. After each fourth month of operation, CO_2 injection is rotated into another area. Thus, a given area will experience a WAG cycle consisting of eight months of water injection followed by four months of CO_2 injection. The volume of CO_2 injected into each area is about 1.5 to 2% HCPV per cycle, and the project is currently in the sixth WAG cycle. Total CO_2 injection after 17 years of operation is designed to be 40% HCPV, including produced CO_2 that is reinjected.

Reservoir Geology

A geological reservoir characterization of the pilot study area (Fig. 1) has been completed by PPCo. The objectives of this investigation were to identify: 1) flow units and inter-well correlation of such zones, 2) overall influence that the depositional facies has on flow units, and 3) stratigraphic/ zone identification of high permeability channels or layers. This geologic information will be incorporated into the reservoir simulation studies that will specifically address the CO_2-foam flood characteristics.

The pilot study area consists of carbonate shallowing upward sequences, 20 to 50 ft thick, which have been extensively dolomitized. The section may be divided into seven major correlatable flow units. Porosity and permeability within the flow units are facies controlled and the flow units are dominantly dolomitized pelodial to oolitic wackestone to grainstones, formed in a subtidal shoal environment.

The two main producing flow units are designated the C and E zones (Fig. 2). These two zones generally show good to excellent porosity with permeability. The C and E zones exhibit consistent quality log porosity (10 to 20%) and core permeability (20 to 50 md). The C zone can be

further subdivided into three correlatable units designated C_3, C_2, and C_1, in descending order; however, there is probably little vertical permeability separation between the three subzones.

CO_2 Flood Performance

As shown in Table 1, the tertiary recovery forecasted for the CO_2 flood is 8% of the original oil in place (OOIP)[2] and production performance to date indicates that this will be exceeded. The net CO_2 utilization factor is estimated to be 6.3 mcf per STB oil recovered. This recovery is typical of other large CO_2 floods in the Permian Basin.[3,4]

While tertiary oil response at the EVGSAU is very favorable, some wells are showing excessive CO_2 breakthrough, thereby increasing CO_2 recycling and compression costs. Since the ultimate purpose of this field demonstration of the use of foam is to reduce CO_2 production and to increase oil displacement effectiveness, a suitable pattern in the EVGSAU was selected for the test.

Pattern Selection and Development

The pattern selected for the test (Fig. 3) was based on the criterion that the production there be typical of other patterns without a distinctly better or worse record of CO_2 breakthrough than in the rest of the field. Oil, water, and gas production in this pattern are shown in Fig. 4. The offending producing well (3332-032) that has experienced greatest CO_2 breakthrough is located to the southwest of the injection well (3332-001). In early 1991, an observation well (3332-003) was drilled in the pattern (shown in Fig. 3) approximately 150 ft to the west of the pattern injection well. This location was selected because: 1) there is good reservoir continuity in that direction, 2) the close proximity to the injector will permit timely evaluation of changes in fluid saturation, and 3) the westerly direction is not directly in line with the known channeling from the injector to the producing

well 3332-032 (which will also serve as a production observation well). The new observation well was cored and logged to improve reservoir characterization in the pattern area, as well as to provide reservoir cores for laboratory tests with suitable surfactants. The coring operations were highly successful in that 285 ft of conventional core was recovered of the 289 ft cored, and 126 ft of sponge core was recovered of the 131 ft taken to cover the pay intervals. Core analyses were conducted by a commercial laboratory. Logs from the new observation well indicated significant oil saturation throughout the entire section. Typically, a minimum oil saturation of 20% was noted in a 30 ft interval between 4460 ft and 4490 ft. However, oil saturations as low as 5% were found in some select samples indicating displacement of oil by CO_2. All other areas showed significantly higher oil saturation of 30 to 50%. The zone of low oil saturation is likely to have been swept by water and CO_2 during the flood. The estimated CO_2 saturation was not unusually high in the zone with low oil saturation. In order to use the borehole as a logging monitor well, the bottom 800 ft was cased with fiberglass.

LABORATORY TESTING

Three criteria were used in our surfactant selection process: 1) the lowering of mobility due to the presence of surfactant in the brine injected with the CO_2, 2) the amount of adsorption of the surfactant onto the reservoir, and 3) the ability of the surfactant to stabilize aqueous-phase bubble films or foam lamellae in dense CO_2 at reservoir-conditions. The principal goal of this work was to select the surfactant and the concentration of that surfactant to be used in the field tests. In all the laboratory experiments, a synthetic brine with the composition shown in Table 2 was used to simulate the EVGSAU reservoir brine.

Foam Mobility

Cores from EVGSAU were used to assess the extent of mobility reduction provided by foaming agents of CO_2 at reservoir conditions. From the injection flow rate (q), the cross-sectional area of the core (A), and the pressure drop (Δp) across the core length (L), the mobility (λ) can be calculated in Darcies per cp, from

$$\lambda = \frac{(q/A)}{(\Delta p/L)} \tag{1}$$

The typical effect is decreasing CO_2-foam mobility with increasing surfactant concentration. At higher surfactant concentrations, the increased population and durability of the lamellae (bubble films) retard the movement of CO_2 through porous media. Actual propagation of the foam will be discussed later. At extremely low or zero surfactant concentration, the mobility is indicative of the combined mobilities of dense CO_2 and brine without surfactant, at the gas-liquid ratio used in the experiment.

Mobility reduction with CO_2-foams will depend on the ratio of the two phases, which is the fraction of the bulk dispersion that is dense CO_2. This ratio can be expressed as the CO_2 fraction or foam quality (as a percentage), or as a gas-liquid volumetric ratio (q_g/q_l). For example, if the gas-liquid volumetric ratio is four, the foam quality is 80%. When steady-state conditions are achieved, a mobility reduction factor (MRF) at a given gas fraction can be calculated

$$\text{MRF} = \frac{\lambda_{g1}}{\lambda_{g2}} \tag{2}$$

where λ_{g1} is the gas phase mobility when no surfactant is present in the brine and λ_{g2} is the gas phase mobility when surfactant is present, and where both mobilities are determined at the same gas-liquid volumetric ratios and at the same flow velocities. The MRF can represent the pressure drop attributed to the presence of foam, provided λ_{g1} and λ_{g2} are determined at the same gas fraction and

flow velocity. If foam is not generated, MRF would be unity. If foam is generated, the MRF values quantify the effect of the presence of foam.

The mobility of foam is lower than it is for the combined flow of CO_2 and surfactant-free brine, because of the presence of fairly stable bubble films or lamellae spanning some of the pores. These prevent the CO_2 from flowing through the rock freely, constrained only by its own low viscosity. Consequently, the MRF depends on the population of these lamellae, and can be expected to vary with the overall flow rate, the flowing fraction of the two phases, and the rock permeability —as well as with the surfactant type and concentration.

Foam flow in porous media can exhibit a moderate shear-thinning behavior. This behavior is consistent with the notion that higher flow rates will decrease the stability of lamellae (bubble films). While the effect is moderate, this behavior is desirable from a field injectivity standpoint in that the apparent viscosity of the foam can be lower near the vicinity of the wellbore than farther into the reservoir, provided that radial flow conditions exist. However, a recent study[5] found that shear-thinning behavior was apparent at flow velocities above about 1 ft/D, but shear-thickening behavior was observed below that rate.

In experiments described by Lee *et al.*,[6] the mobility did not exhibit the same proportionality to rock permeability as that shown by a simple fluid that follows Darcy's law. In fact, over a range of rock permeability from 4 to 200 md, the mobility did not increase appreciably. Above and below that range of permeability, the expected proportionality was gradually attained. 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. The effect of rock permeability on foam mobility can depend on the hydrophilic nature of the surfactant and on

the stability of the foam.[5] Depending on hydrophilicity, some surfactants yielded a favorable dependence on permeability while others did not.

For foam to be continuously generated in situ, a critical gas velocity or critical pressure gradient must be exceeded.[7] However, a minimum pressure gradient may be required to initiate and sustain foam flow. This latter concept is controversial, and further laboratory tests are needed to fully assess the importance of this mechanism. When the foam mobility and propagation tests are done with an oil phase present in cores, the observed behavior can be very complicated and will depend on whether the foam is stable or unstable, on whether viscous emulsions are formed, and also on the foam-bubble coalescence-time relative to bubble snap-off time.[5] Unstable foams that break and reform may be desirable so that the foam can be propagated through a reservoir at a satisfactory rate.[5]

A commonly used expression to assess the magnitude of mobility reduction is the "resistance factor." The resistance factor, when only CO_2 is flowing through a core, is the CO_2 mobility before foam flow divided by CO_2 mobility after foam. The resistance factor during foam flow is the mobility of the CO_2/brine mixture divided by the mobility of the CO_2/surfactant solution where both measurements are conducted at the same gas-liquid volumetric ratio. Because of the dependence of velocity on foam mobility, resistance factors are calculated at a constant velocity.

Foam Mobility Measurements

The mobility of CO_2-foam was measured during flow of dense CO_2 and surfactant solution in short core plugs that were cut from preserved core recovered from the new observation well (3332-003). In the PRRC experiments, simultaneous injections of dense CO_2 and surfactant solution at high pressures were conducted long enough to achieve steady-state mobilities. The experimental apparatus and details are described elsewhere.[8] Because these experiments simulate portions of a reservoir

behind a stable displacement front where most of the oil will have been displaced by the CO_2, the PRRC tests were conducted in preserved core plugs after the plugs were flushed with a synthetic field brine. The PRRC tests were conducted at Darcy velocities ranging from 1.5 to 10 ft/D (2.5 to 16.5 cc/hr) and the PPCo tests were conducted at a Darcy velocity of 40 ft/D (40 cc/hr). In all tests reported herein, a gas-liquid volumetric ratio of four was used, thus, 80% quality foam. In the PPCo tests, the EVGSAU reservoir cores were subjected to the following sequence: waterflood, oilflood, waterflood, CO_2 flood, surfactant injection, CO_2 flood, simultaneous injection of surfactant solution and CO_2, and finally a CO_2 flood.

In the PRRC experiments described in this paper, tests were performed with four different surfactants in cores taken from the higher permeability horizon in the formation. Other tests have been conducted in lower permeability cores from EVGSAU.[9] Fig. 5 shows the CO_2 foam mobilities at a velocity of 4 ft/day as a function of surfactant concentration. The three different curves represent data from three different surfactants, each in a different core plug cut from this higher permeability group. At 750 ppm (0.075 % active material) concentration, the mobility of Chevron CD-1045® in a 640 md core was less than half that of Henkel NES-25® in the 436 md core, and about equal to the mobility of a foam made with PPG/Mazer Avanel S-30® in a 189 md core. The variation of foam mobility with velocity is shown in Fig. 6 for CD-1045.® This figure, like those with similar curves using data from the other surfactants, shows the moderate shear thinning effect noted above.

A schematic diagram of the closed system PPCo apparatus used for the dynamic foam mobility tests is shown in Fig. 7. Two Beckmann pumps maintain a constant upstream pressure of 2000 psi, and the motorized Ruska pump is connected to the downstream as a withdrawal pump to obtain constant flow rates of 40 cc/hr (40 ft/D). An Isco pump is used to pressurize and inject the brine/surfactant solution into the core. The core has three pressure taps to measure the pressure drop across the core. The most important pressure data is the change in pressure over the center of the

core. The pressure between taps is measured by a Validyne differential pressure transducer. Analog outputs from the Validyne differential pressure transducers are sent to an HP9121 computer through an HP3497A Data Acquisition/Control Unit, and the digital outputs are stored on diskettes. When injecting simultaneously CO_2 and aqueous surfactant, the setting of the Isco pump gives the flow rate of the aqueous surfactant solution, and the CO_2 flow rate is determined by subtracting the aqueous surfactant flow rate from the constant withdrawal flow rate.

PPCo used a 1 in. diameter by 3 in. length EVGSAU core plug of 254 md brine permeability to examine the surfactant effectiveness in the presence of oil. The core was saturated with the synthetic brine that had been filtered through a 0.45μ membrane filter, oilflooded to restore the core to initial water saturations, waterflooded to residual oil saturation (S_{or}), and then flooded with carbon dioxide to miscible residual oil saturation (S_{orm}). In each test, foam was generated by first injecting CO_2 into a surfactant-filled core, and then simultaneously injecting CO_2 and surfactant solution in a 4:1 ratio, corresponding to 80% quality foam. At the end of test, the core was flushed with brine (>80 PV) to displace all the surfactant and restore the core to its original condition. This was confirmed by the waterflood permeability measurements, which increased only slightly between successive runs. A typical PPCo injection sequence is given in Table 3.

Figs. 8, 9, and 10 show the change in pressure vs. volume injected at concentrations of 0.05, 0.1 and 0.5 wt% active, respectively, for the three surfactants that PPCo tested: Chevron CD-1045®, Henkel NES-25®, and Rhone Poulenc Alipal CD-128®. Mobility during coinjection of CO_2 and surfactant is plotted in Fig. 11. Mobility decreased with increasing concentration. The rate of mobility decrease was higher at the lower concentration (<0.1 wt% active) and decreased at the higher concentration. When coinjecting CO_2 and surfactant, the differential pressure drop across the core was more than twice the pressure drop measured during the surfactant-alternating-gas (SAG) process. Simultaneous injection of surfactant and CO_2 gave better foaming than did the SAG process. Fig. 12

shows that CD-1045® foams resisted displacement by CO_2 and lasted longer in the SAG process at 0.5% active surfactant.

Surfactant Adsorption

For CO_2-foam to propagate through a reservoir at a satisfactory rate, the amount of surfactant adsorption is a critical factor. Fortunately, since the concentration of suitable surfactants needed for CO_2-foams is much less than required for propagation of surfactants in chemical flooding, a lower level of surfactant adsorption may be expected. Recent information[10] suggests that the amount of surfactant adsorption may be reduced even further if a low surfactant concentration (below the critical micelle concentration) is used. Three different methods were used to assess surfactant adsorption during the CO_2-foam tests in reservoir cores. The PRRC laboratory used a dynamic slug method, and the PPCo laboratory used a recirculation method and a flow-through method.

Dynamic Slug Method

A dynamic slug method for the measurement of surfactant adsorption in a small core sample was developed in the PRRC laboratory. The method is applicable to different types of surfactants at low concentrations-from the critical micelle concentration (CMC) down to about 1/100 of this value. This method is a modified drop-weight method (MDWM), based on the drop-weight method of surface tension measurement, and modified through the use of a constant rate pump that allows a measurement of time between drops rather than weight. By use of a liquid chromatograph valve, a known volume of surfactant solution at the desired concentration is allowed to flow through a brine-saturated test core sample to initiate the experiment. Surfactant in the effluent is continuously monitored by timing the drops to determine the amount adsorbed, as well as the chromatographic delay in transport of the slug. Adsorption of both nonionic and anionic surfactant samples onto

reservoir rocks have been measured using this MDWM in a direct flow-through measurement. The results indicate that the amount of adsorption varies with the surfactant concentration and with the duration of exposure. This is evident from the dependence on slug size and flow rate. With sufficient slug size, results such as those in Fig. 13 are obtained. At concentrations below the CMC, surfactant adsorption increases with surfactant concentration, and the maximum adsorption level as derived from the MDWM are comparable with the numbers produced by other methods. Tables 4 and 5 list the results of the PRRC adsorption measurements in low permeability EVGSAU cores and high permeability EVGSAU cores, respectively.

Recirculation Method (NES-25® and Alipal CD-128®)

Surfactant adsorption was measured by PPCo using the recirculation method in a core plug cleaned by the Dean Stark method using toluene and methanol. The recirculation experimental apparatus consisted of a closed system of brine having a known weight and a core of known volume as shown in Fig. 14. At the beginning, only brine was circulated through the core. A known weight was removed from the system and replaced with a known amount of a known concentration of surfactant solution. The solution was circulated through the core at 0.5-0.6 cc/min for one day. Another sample was removed from the system and more surfactant was added. The concentrations of samples were determined by a chemical method using a UV/VIS spectrophotometer. Comparing the concentration results to what the concentration should be if no adsorption occurred, the amount adsorbed was determined. The cycle of sampling and adding was repeated until no additional surfactant was adsorbed. The adsorption of NES-25® on the surface of a core that has 6.1% porosity is approximately 1550 lb/acre-ft as shown in Fig. 15. The adsorption of Alipal CD-128® on the surface of a core that has 5.6% porosity is approximately 1600 lb/acre-ft as shown in Fig. 16.

Flow-Through Method (CD-1045®)

Chevron CD-1045® is a multicomponent formulation that requires a special analytical procedure to measure concentration. The individual components could not be determined easily by wet chemical methods. PPCo used an on-line refractometer to measure the surfactant concentration.

Fig. 17 is a schematic diagram of the PPCo apparatus for measuring CD-1045® adsorption. The cleaned core was epoxied and mounted in a core holder surrounded by a heating jacket. A Waters R401 refractometer with its associated electronics unit was installed on-line to measure CD-1045® concentration in the effluent from the core. This instrument is several orders of magnitude more sensitive than either a hand-held or an Abbe refractometer. The refractometer signal was sent to a strip chart recorder.

Many pore volumes of brine were pumped through the core initially to obtain a stable baseline. A surfactant solution containing 1000 ppm of CD-1045® was prepared with the EVGSAU brine and pumped through the core until the effluent concentration levelled off and reached steady state. Once the signal of the recorder was at steady state, the brine was pumped and the core was flushed with brine.

Three steps were involved in calculating the adsorption: (1) conversion of strip chart data to concentration vs. pore volume injected, (2) calculation of the area under the effluent profile, and (3) subtraction of the amount of surfactant in effluent from the amount of surfactant injected.

The flow-through method is a rapid method to determine the amount of adsorption compared to the recirculation method, but it provides only the final adsorption value while the recirculation method gives the whole isotherm adsorption curve. Figs. 18 and 19 show the effluent concentration

profiles for a CD-1045® adsorption test. The adsorption of CD-1045® on the surface of the core which has 14% porosity is approximately 500 lbs/acre-ft as calculated from data in Fig. 18. The adsorption of CD-1045® on the surface of the core which has 16.2% porosity is approximately 1130 lbs/acre-ft as calculated from Fig. 19.

Summary of Adsorption Tests

A summary of all the PRRC and PPCo data on adsorption of surfactants is provided in Table 6. Measured surfactant adsorption levels increased with surfactant concentration up to a limiting value, and ranged from about 600 lb/acre-ft to 2600 lb/acre-ft.

Foam Durability Measurements

Assessment of the surfactant properties with dense CO_2 at high pressures was first conducted in the laboratory by using the foam durability apparatus. This apparatus is a device used for testing the foamability of surfactant with dense CO_2 and the durability of foam, thus enabling a quick evaluation of the surfactants for reservoir use.[6] The tests were designed to select surfactants that might be suitable for the stabilization of bubble films or lamellae in a reservoir condition. Other results obtainable from these tests include measurements of the interfacial tension (IFT) between dense CO_2 and surfactant solution, and the CMC of a surfactant at reservoir conditions.

In these tests, bubbles of dense CO_2 are introduced through a needle into the lower end of a high-pressure visual cell initially filled with the surfactant solution. This is done at a constant rate by withdrawing the surfactant solution by means of a Ruska pump. A measure of the 'foamability' of this surfactant is the fraction of the bubbles that stay intact in a foam at the top of the cell. The

'durability' of the foam is determined in terms of foam decay by measuring the change of the percent of foam or coalescence of the bubbles.

For standard measurements, tests were conducted at two conditions of temperature and pressure—77°F/1500 psig and 104°F/2500 psig. Detailed results are summarized in Table 7 which include the CMCs, IFTs between surfactant and dense CO_2 at CMCs, and foamability as well as durability. The foamability and durability are reported at surfactant concentrations near the CMC values. No significant difference in the CMCs is found at the two test conditions, even though the surfactants differ from each other. The CMCs are in the range of 0.04 to 0.07 wt% active. In general, the effectiveness of surfactant to form foam and to stabilize bubble films is found to be higher at lower temperatures.

To test for chemical or thermal degradation of the surfactants, the samples were intentionally aged at two conditions for 30 days before the tests. The desktop-aged samples were stored in sealed jars at room temperature for 30 days; whereas the oven-aged samples were stored inside an oven at 140°F for the same period of time. The relevant data for the aged sample are summarized in Table 8. For three of the surfactants tested, no significant changes of the CMC, or of the IFTs at CMCs, are found as a result of the aging. The foamability and durability of foam for these surfactants are found to have decreased slightly when the surfactant concentrations tested were below 200 ppm. At concentrations above 200 ppm, the only decrease of foam durability was found in NES-25®. However, the shortest lifetime of foam is still greater than 0.5 hours, suggesting that all of those tested might be sufficiently durable far behind the frontal region, in rock containing little or no oil.

To study the effect of crude oil on the foam's activity with different surfactants, the standard test procedures were slightly modified. Before the surfactant was pressurized to receive the injected CO_2, a small amount of crude oil was introduced into the top of the cell first. Table 9 summarizes

the foam's activities for all fresh and aged surfactant samples tested against the crude oil. The oil had the expected effect, and in all cases the CO_2 bubbles coalesced much more rapidly. However, the bubble breaking effect can be compensated for by increasing the surfactant concentration. At the same concentration levels, though, the bubble breaking effect can be ranked as CD-1045® < CD-1050® < Avanel S-30® < NES-25® (that is, the CO_2-foam made with CD-1045® sustains the effect of oil to the greatest extent). In a miscible flood, such as a mobility-controlled CO_2-foam flood, the breaking of foam can increase the incidence of dense CO_2 in contact with oil. Ahead of the displacing front, it would be beneficial to have the foam broken to some extent. As to the application of an immiscible flood, the breaking of foam in a displacing front will cause frontal instability again. Therefore, the engineer should be cautious in considering the surfactants Avanel S-30® and NES-25® as foaming agents for application in immiscible floods, especially at low concentration levels.

Summary of Laboratory Results

Of the commercially available surfactants that were tested, CD-1045® generated the most stable foam. Several of the surfactants tested were effective in reducing CO_2 mobility in EVGSAU cores at reservoir conditions, and as expected, higher surfactant concentrations were more effective, but mobility reduction did not change dramatically when surfactant concentrations were increased from 0.1% to 0.5% active (1000 to 5000 ppm).

Because the CD-1045® is a multi-component formulation, there was concern that chromatographic separation of the components in the reservoir could occur that would decrease the effectiveness of this surfactant. Slim tubes (7.8 ID x 30 cm) containing crushed EVGSAU core material were used in High Performance Liquid Chromatographic (HPLC) tests to assess the possibility of chromatographic separation. In tests conducted by PPCo (not given in this report) CD-1045®, NES-25®, and Alipal CD-128® had multiple peaks in the chromatographic tests which would

indicate multiple components, whereas Avanel S-30® and another surfactant eluted as a single peak. However, when injection volumes analogous to field usage were used, all components of CD-1045® eluted in a single, broad peak. Thus, chromatographic separation in the reservoir is not expected to be a serious problem in the field test.

SURFACTANT SELECTION

From an evaluation of results presented in this paper, results presented elsewhere,[9,11] in-house PPCo results, surfactant cost data, and other factors such as surfactant handleability, a consensus of the JPAT representatives favored the selection of CD-1045® for the field test at EVGSAU. Additionally, the JPAT representatives agreed that the concentration of the surfactant should be 2500 ppm for both the pre-foam pad used to satisfy surfactant adsorption in the reservoir as well as for the surfactant solution used during the surfactant-alternating-gas (SAG) cycle of the field test.

RESERVOIR SIMULATION STUDIES

The reservoir simulation studies for this project are being conducted by Dr. John Killough at the University of Houston. These studies have progressed on three fronts: reformulating the mechanistic foam model, developing a modified simulator for CO_2-foam, and building the history match model for the field pilot area.

To better understand the simulation of the CO_2-foam process, the mechanistic model from the PRRC was used.[12] The first step of the study investigated the effect of radial, near-well, flow on foam generation. The mechanistic foam model was modified to include a radial coordinate system. Simulations with this model showed that significant instabilities were encountered due to the explicit handling of the bubble population balance equation. To improve the stability of the model, the

original version was modified to include the fully-implicit treatment of the bubble density terms. This modified version appeared to show better stability; however, further testing is required. These revisions will be used in the modified foam model for the field pilot.

A commercial, miscible flood, four-component, Todd-Longstaff-type simulator was modified to include the explicit treatment of the foam flow. These additions were made and the changes are being debugged. From the insight gained on the mechanistic model, the miscible flood simulator will be modified as required.

Geological and production data for the pilot area were supplied by PPCo. The geological data were used to develop a realistic description of the pilot area. These data were digitized for the initial pass at the history match.

SMALL-SCALE VARIABILITY IN EVGSAU CORES

Geostatistical calculations were made on two data sets from cores taken from this formation. The first set consisted of closely-spaced permeability measurements from the slabbed face of a full core from the producing formation. These minipermeameter measurements were analyzed using the methods of geostatistics[13] to yield estimates of the *correlation length* and the values of the *variogram* at different values of lag distance. (The unit measure of these variograms is the square of the difference in natural logarithms, of the permeabilities at different points.) Some differences were evident between the variograms for pairs of measurements separated by vertical *lag distances*, and those pairs separated by horizontal lags. The correlation lengths for both were about 0.05 ft., but while the graph made with horizontal point-pairs rose to a definite *sill* value of about 1.2, the curve made with points separated vertically increased to 2, and was perhaps still increasing at lag distances of 0.4 ft., the largest value for which statistically significant values could be obtained.

In the second data set, the porosity values and the vertical and horizontal permeability measurements made on whole cores at a commercial laboratory were treated in a similar manner. Variograms could be computed for lag distances between about 0.5 ft and 50 ft. Two interesting features of the analysis of this data were that the variograms for porosity and for vertical permeability were quite similar. The lowest values of the permeability variogram were between 1.5 and 2.0. They appeared to be continuations of the variogram made with vertically separated pairs made on the smaller scale, and also showed evidence of the layering observable on the well logs, along with a generally rising value of the variance. One last result of the statistical analysis of this data set was a cross-plot of the porosity and vertical permeability. Although a large amount of scatter is evident (of about a factor of ten in the permeabilities), a "best straight line" correlation could be computed.

These geostatistical studies indicate the magnitude of the formation's permeability variations, which are of significance in the efficiency of the miscible CO_2 flood.

PROJECT PLANS AND SCHEDULE

Baseline Data

Detailed historical data are being obtained for the pattern prior to startup of the foam test. A baseline period prior to foam injection attempted to mimic the proposed foam injection period in flow rates and scheduling. This was done to have a control data period for comparison to the actual foam cycle data.

Although the laboratory results indicated that simultaneous injection of surfactant solution and CO_2 was desirable, operational problems were anticipated with co-injection in that line pressure varies considerably between water and CO_2. Thus, a rapid SAG injection mode was selected that is

expected to closely approach the benefits achieved by simultaneous injection. This rapid SAG process involves a three-day cycle of water followed by a twelve-day cycle of CO_2 to give an approximate 80% quality foam. The three- and twelve-day cycles were selected over a more rapid cycle because this schedule can be maintained throughout the project. Because the mechanical characteristics of a SAG may cause changes in injection pressure, a baseline period of a rapid WAG was performed.

The collection of pre-foam baseline data is important for the subsequent evaluation of performance of the CO_2-foam test. These data include well injectivity, injection profiles, CO_2 breakthrough in producers, pressure transient tests, interwell tracers, and production well testing of the eight wells in the pattern area collected on a weekly basis.

Project Monitoring

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. Foam propagation will then be inferred from 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 be calculated from the inflection point of the pressure-time plot. The distance should approximate that which is determined by a material balance calculation and includes surfactant retention.

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; however, a pressure transient test is necessary to separate skin effect from mobility reduction.

Changes in fluid entry profiles 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) would confirm fluid diversion. Pilot area production history since unitization is shown in Fig. 20. The data are presented in a GOR vs. cumulative oil produced form to facilitate a rapid estimate of possible future incremental oil recovery; however, shut-in time is not included in this form. Notice that the GOR scales are not uniform. 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. The short-term assessment of mobility control vs. fluid diversion will be based on response time of produced GOR's. It is believed that a reduction in GOR resulting from mobility control will occur over a long time period, and this would be supported by transient pressure test history. GOR changes as a result of fluid diversion occur rapidly and are supported by fluid entry profiles at the injection well.

The observation well will be used to monitor changes in fluid saturations during the project for the assessment of mobility control. At the end of each cycle, a Phasor Induction and a Compensated Neutron log will be run to detect saturation changes.

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.

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.

Project Schedule

A revised project schedule is shown in Fig. 21. CO_2 injection into the pattern was curtailed when problems evolved in obtaining permits from the State and it was necessary to shut in wells that were producing large volumes of CO_2. The pattern injector was put back on CO_2 injection in the first part of October 1991. The rapid WAG cycle was started in September 1991 and was completed in December 1991, followed by the three-month CO_2 injection cycle. At that time, the baseline testing will be completed, and the foam cycle will commence. For the first month of the foam cycle, water with no surfactant will be injected at a rate of 1000 BWPD. Then the pre-foam surfactant pad will be injected for up to three months. The surfactant concentration will be 2500 ppm and the pad will contain tritiated water as a tracer. After the normal four months of water injection, the rapid SAG portion of the foam cycle will commence with a surfactant concentration of 2500 ppm in the water used to generate the foam.

CONCLUSIONS

During the second year of this project, the primary emphasis of the work was directed at surfactant selection for the proposed field test at EVGSAU. Laboratory core tests were conducted with several commercial surfactants to evaluate mobility reduction and surfactant adsorption during foam flow. The following are the major conclusions obtained during the second year of this project.

1. Several commercial surfactants generated stable foam at reservoir conditions in the laboratory tests. The level of mobility reduction achieved decreased as surfactant concentration increased but did not change substantially when surfactant concentration was increased from 1000 to 5000 ppm. Surfactant adsorption increased with surfactant concentration up to a limiting value, and ranged from about 600 lbs/acre-ft to 2600 lbs/acre-ft.

2. Chevron CD-1045® was selected by the JPAT members for the field test that will commence in the Spring of 1992. Based on the various laboratory procedures, the adsorption level of CD-1045® is expected to be in the range of 1100 lbs/acre-ft in the portion of the reservoir contacted by surfactant solution.

3. The design that was developed calls for the injection of three months of a pre-foam surfactant pad to satisfy the adsorption requirement of the reservoir, followed by the injection of an 80% quality CO_2-foam during four months of a rapid SAG cycle. Surfactant concentration in the pre-foam pad and in the surfactant solution for the SAG cycle will be 2500 ppm CD-1045.®

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TABLE 1
EVGSAU RESERVOIR PARAMETERS[2]

Reservoir and Fluid Characteristics	
Type Formation	dolomite
Depth (ft)	4400
Reservoir Temperature (°F)	101
Original Reservoir Pressure (psig)	1613
Current Average Reservoir Pressure (psig)	2100
Average Net Pay (ft)	71
Average Porosity (%)	11.7
Average Permeability (md)	11.0
Unit Area (acres)	7025
CO_2 Project Area (acres)	5000
Oil Gravity (°API)	38
OOIP (MMSTBO)	297

Forecasted Recoveries	MMSTBO	% OOIP
Primary	78.0	25
Secondary	40.8	15
Tertiary	20.7	8*

*of CO_2 project area

TABLE 2
COMPOSITION OF EVGSAU SYNTHETIC RESERVOIR BRINE

Component	gm/1000 gm solution
NaCl	30.628
KCl	0.290
$CaCl_2 \cdot H_2O$	4.769
$MgCl_2 \cdot 6H_2O$	2.594
Na_2SO_4	2.957
H_2O	958.762

TABLE 3
INJECTION SEQUENCE FOR PPCo TESTS IN EVGSAU CORE

Fluid	PV
1. Brine	8
2. Oil	8
3. Brine	10
4. CO_2(1)	18
5. Surfactant	5
6. CO_2(2)	20
7. Surfactant + CO_2	15
8. CO_2(3)	22

TABLE 4
SURFACTANT ADSORPTION IN PRRC TESTS WITH
LOW PERMEABILITY EVGSAU CORES

Surfactant Type	Rock porosity (%)	Surfactant concentration (ppm)	Amount of adsorption		
			(mg/cc rock)	(lb/ac-ft)	(mg/gm rock)
CD-1050®	12.5	150	0.150	408.84	0.0598
		250	0.242	659.36	0.0965
CD-1045®	14.7	150	0.178	485.13	0.0728
		250	0.414	1126.27	0.1692
		500	0.941	2558.94	0.3843
NES-25®	13.0	150	0.141	384.71	0.0567
		250	0.262	714.93	0.1053
		500	0.759	2063.92	0.3039
Avanel S-30®	14.3	150	0.118	320.89	0.0479
		250	0.342	930.04	0.1391
		500	0.958	2605.30	0.3895
Flow rate: 5 cc/hr					

TABLE 5
SURFACTANT ADSORPTION IN PRRC TESTS WITH
HIGH PERMEABILITY EVGSAU CORES

Surfactant Type	Rock porosity (%)	Surfactant conc. (ppm)	Amount of adsorption		
			mg/cc rock	lb/ac-ft	mg/gm rock
CD-1050®	18.6	150	0.098	265.70	0.0418
		250	0.331	900.11	0.1416
CD-1045®	13.2	150	0.226	616.57	0.0910
		250	0.364	989.18	0.1460
		500	0.609	1655.49	0.2443
		750	0.680	1849.38	0.2730
	18.7	150	0.254	690.93	0.1089
		250	0.352	956.14	0.1597
		500	0.728	1978.36	0.3118
		750	0.802	2181.53	0.3438
NES-25®	16.6	150	0.040	108.24	0.0166
		250	0.290	787.70	0.1210
		500	0.740	2014.95	0.3096
		750	1.019	2771.80	0.4258
Avanel S-30®	14.6	150	0.143	387.78	0.0581
		250	0.204	554.53	0.0832
		750	0.672	1827.46	0.2742
Flow rate: 5 cc/hr					

TABLE 6
SUMMARY OF SURFACTANT ADSORPTION TESTS

Surfactant CD-1045®	Surfactant Adsorption, lbs/acre-ft	
150 ppm	~600*	
250 ppm	~1000*	
500 ppm	~1650*	
750 ppm	~1800*	
1000 ppm	-	500-1300**
Surfactant NES-25®		
250 ppm	800*	~800***
500 ppm	~2000*	~1100***
600 ppm	~2300*	~1400***
700 ppm	~2600*	1500***
>1000 ppm	-	1550***

Methods Used
*Modified Drop-Weight Method
**Flow-Through Method using Cores with Different Porosities
***Recirculation Method

TABLE 7
SUMMARY OF FOAM DURABILITY MEASUREMENTS

Surfactant	Test conditions		CMC (wt%)	IFT @ CMC (dyne/cm)	Foamability (%)	Durability (hours)
	T (°F)	P (psig)				
CD-1045®	77	1500	0.07	3.2	100	>5
	104	2500	0.07	3.0	100	>5
CD-1050®	77	1500	0.05	4.2	100	1.8
	104	2500	0.05	4.0	13	0.2
NES-25®	77	1500	0.05	4.8	100	5
	104	2500	0.04	4.7	84	>5
Avanel S-30®	77	1500	0.05	5.0	100	>5
	104	2500	0.05	4.5	100	>5

TABLE 8
SUMMARY OF FOAM DURABILITY MEASUREMENTS OF AGED SURFACTANTS

Surfactant	Test conditions		CMC (wt%)		IFT @ CMC (dyne/cm)		Foamability (%)		Durability (hours)	
	T (°F)	P (psig)	OA	DA	OA	DA	OA	DA	OA	DA
CD-1045®	104	2500	0.06	0.06	2.9	2.8	100	100	>5	>5
NES-25®	104	2500	0.06	0.06	4.7	4.7	49	92	0.5	>5
Avanel S-30®	104	2500	0.05	0.06	3.5	4.3	95	100	4.0	>5

OA: oven-aged sample
DA: desktop-aged sample

TABLE 9
EFFECT OF CRUDE OIL ON FOAM ACTIVITIES

Surfactant	Concentration (ppm)	Foamability (%)	Durability (hours)
CD-1045®	1000	100	>5
CD-1045®/oil	1000	15.5	3
CD-1045® OA	1000	100	>5
CD-1045® OA/oil	1000	31.2	>5
CD-1045® DA	1000	100	>5
CD-1045® DA/oil	1000	13.2	1.5
CD-104522®	400	100	>5
CD-1045®/oil	500	9.5	0.25
CD-1050®	500	28.5	1.0
CD-1050®/oil	500	20.6	0.08
NES-25®	500	84.5	>5
NES-25®/oil	500	0	0
NES-25® OA	500	48.5	0.5
NES-25® OA/oil	500	0	0
NES-25® DA	500	91.6	4.0
NES-25® DA/oil	500	2.3	0.02
Avanel S-30®	500	100	5
Avanel S-30®/oil	500	0	0
Avanel S-30® OA	500	100	>5.0
Avanel S-30® OA/oil	500	8.0	0.25
Avanel S-30® DA	500	100	>5.0
Avanel S-30® DA/oil	500	6.1	0.08
Avanel S-30®	5000	100	5
Avanel S-30®/oil	5000	13	1.25

Test conditions: 104°F and 2500 psig
OA: oven-aged sample
DA: desktop-aged sample

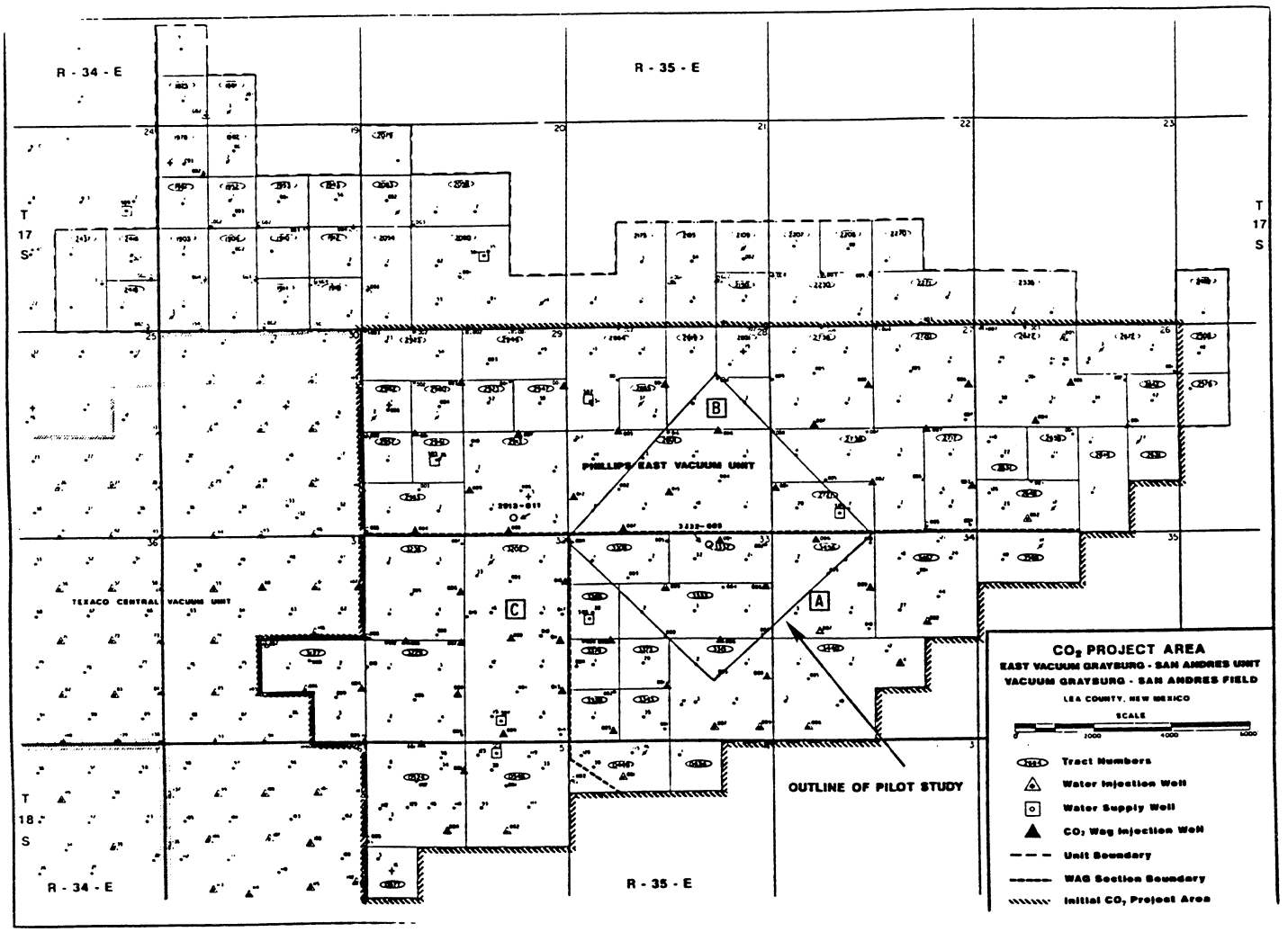

Figure 1. A geological reservoir characterization of the pilot study area.

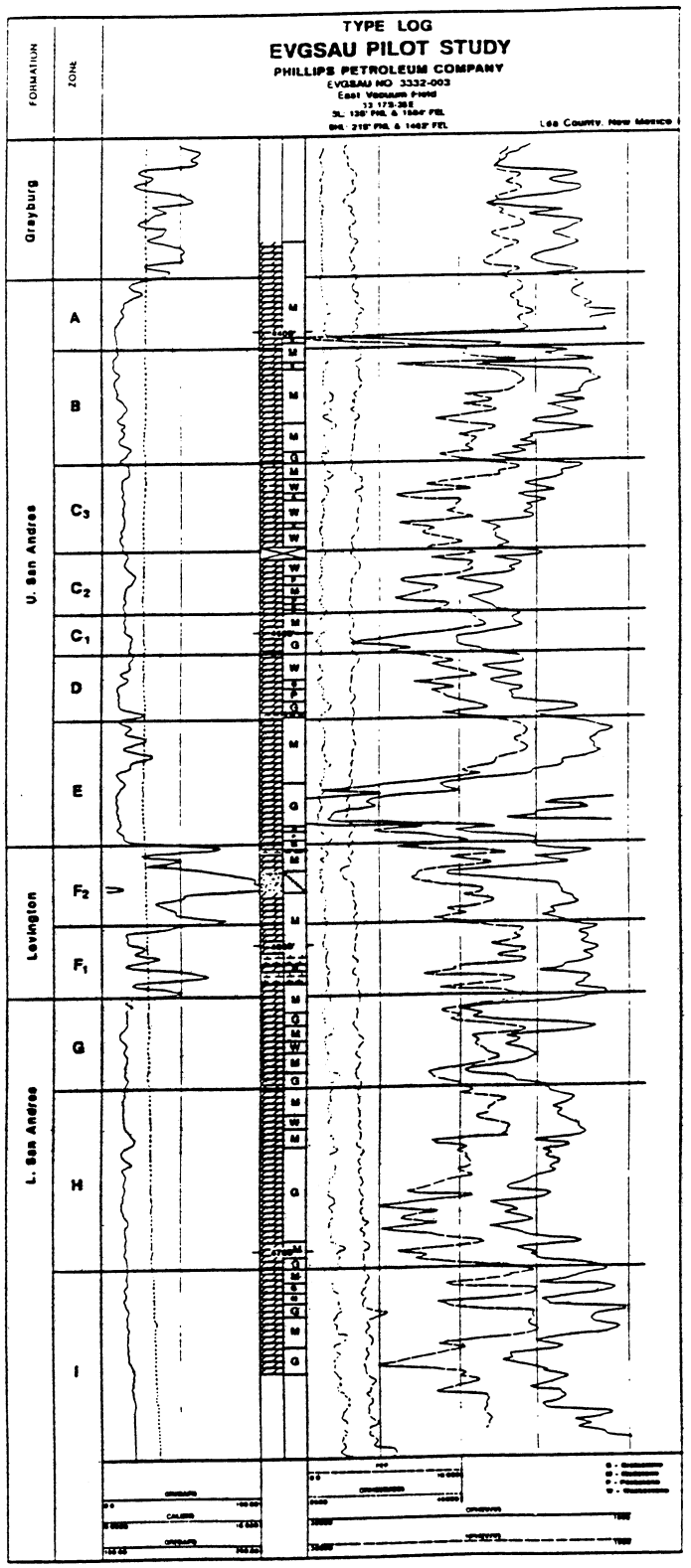

Figure 2. The two main producing flow units are designated the C and E zones.

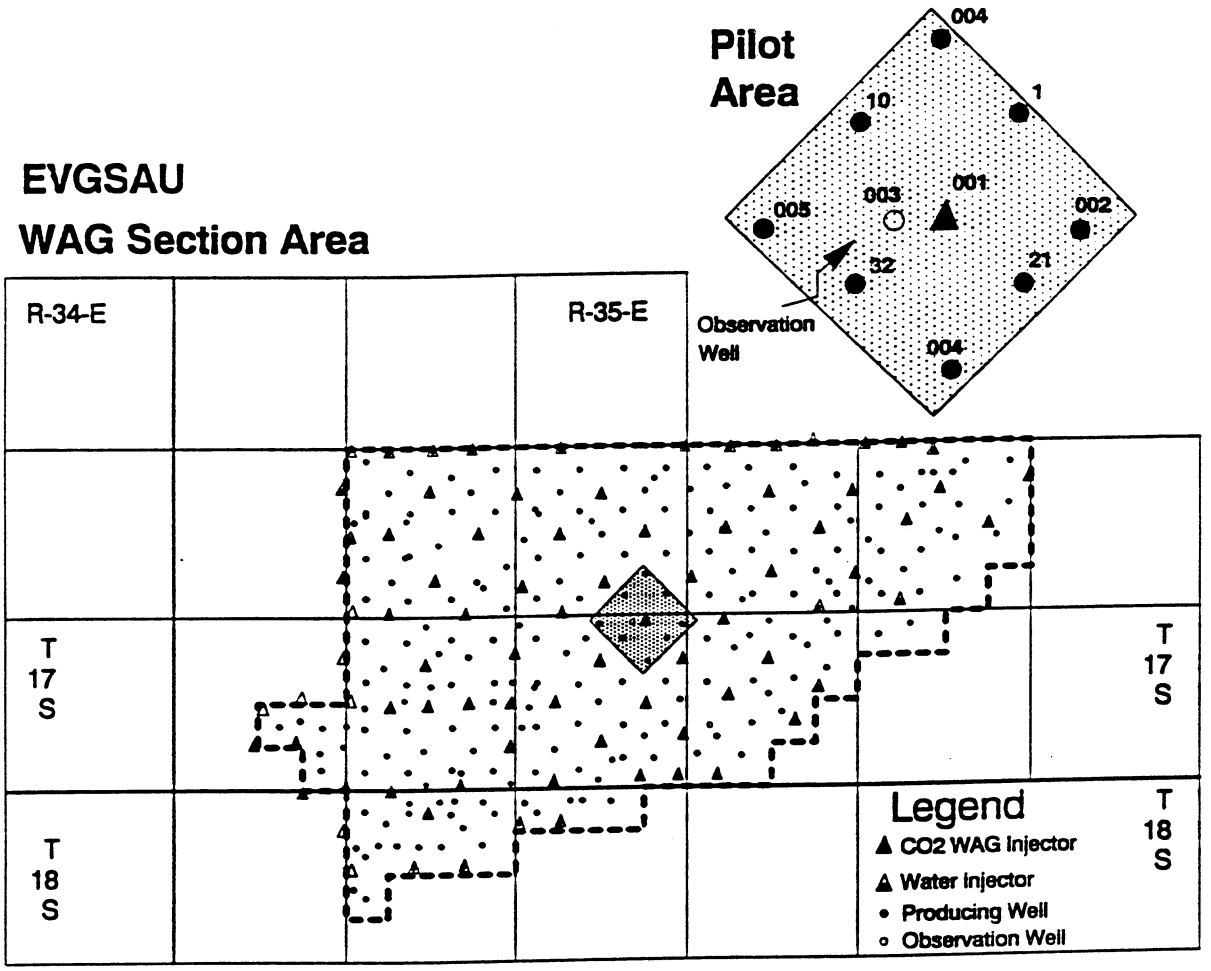

Figure 3. Location of the observation well.

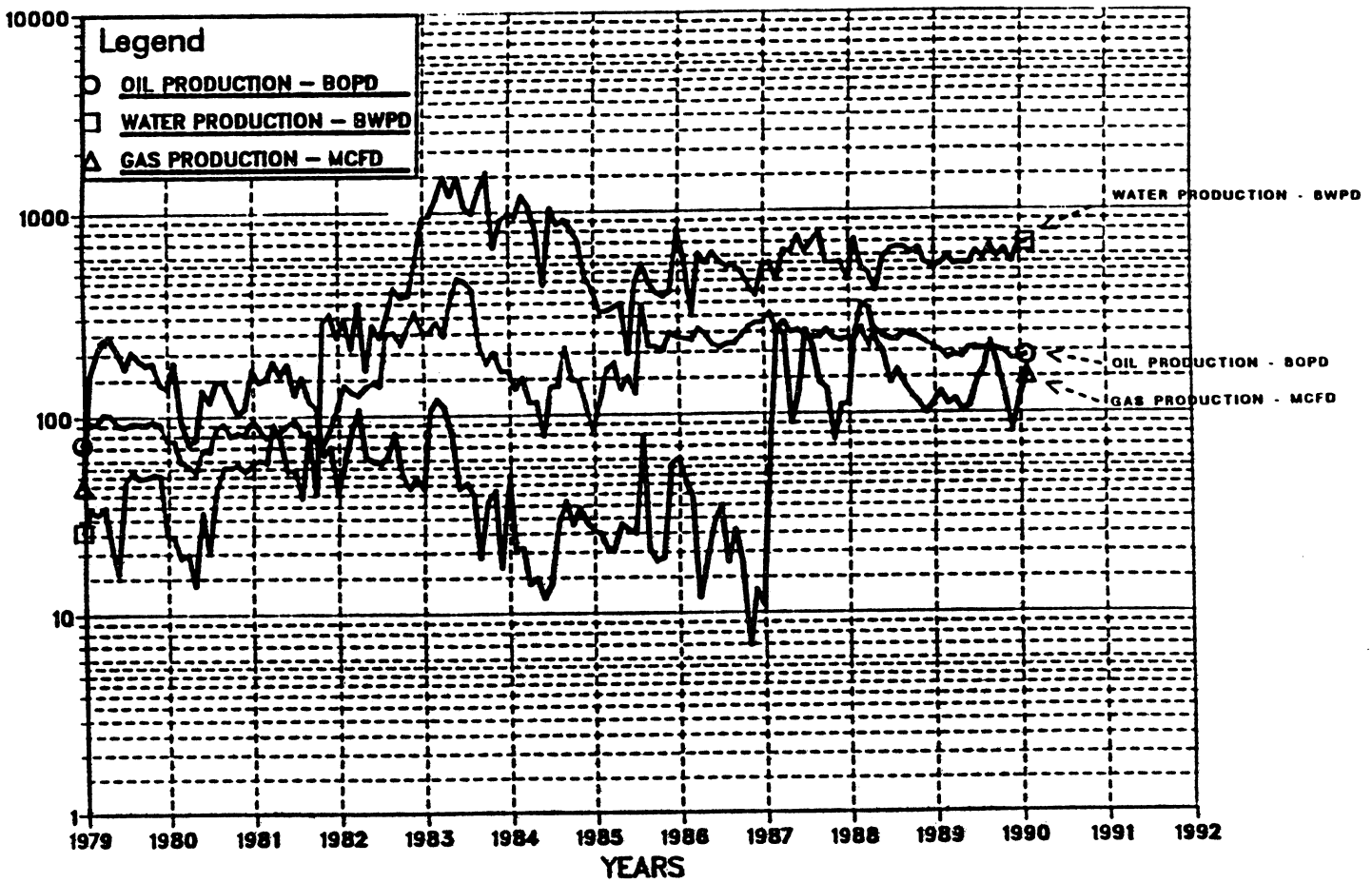

Figure 4. EVGSAU pattern 3332–W001—oil, water, and gas production.

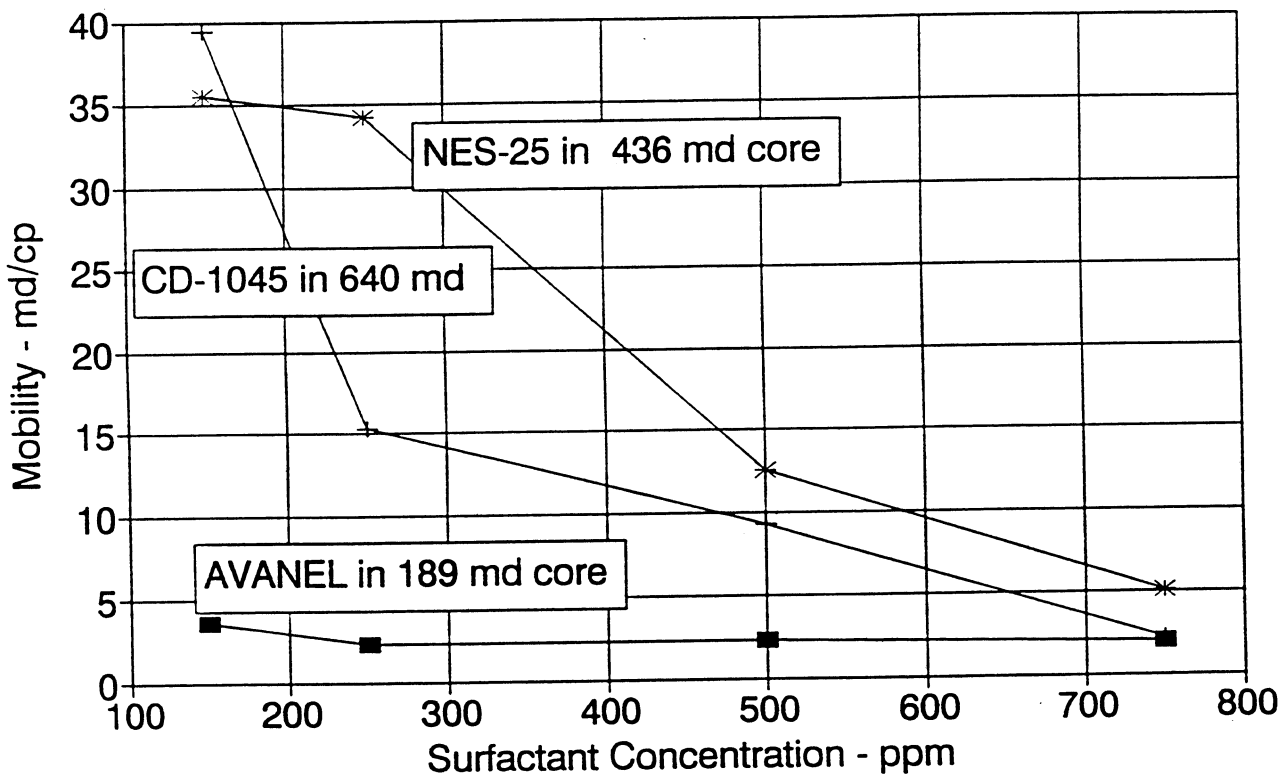

Figure 5. CO_2 foam mobility (4 ft/day, 101°F, 2100 psig).

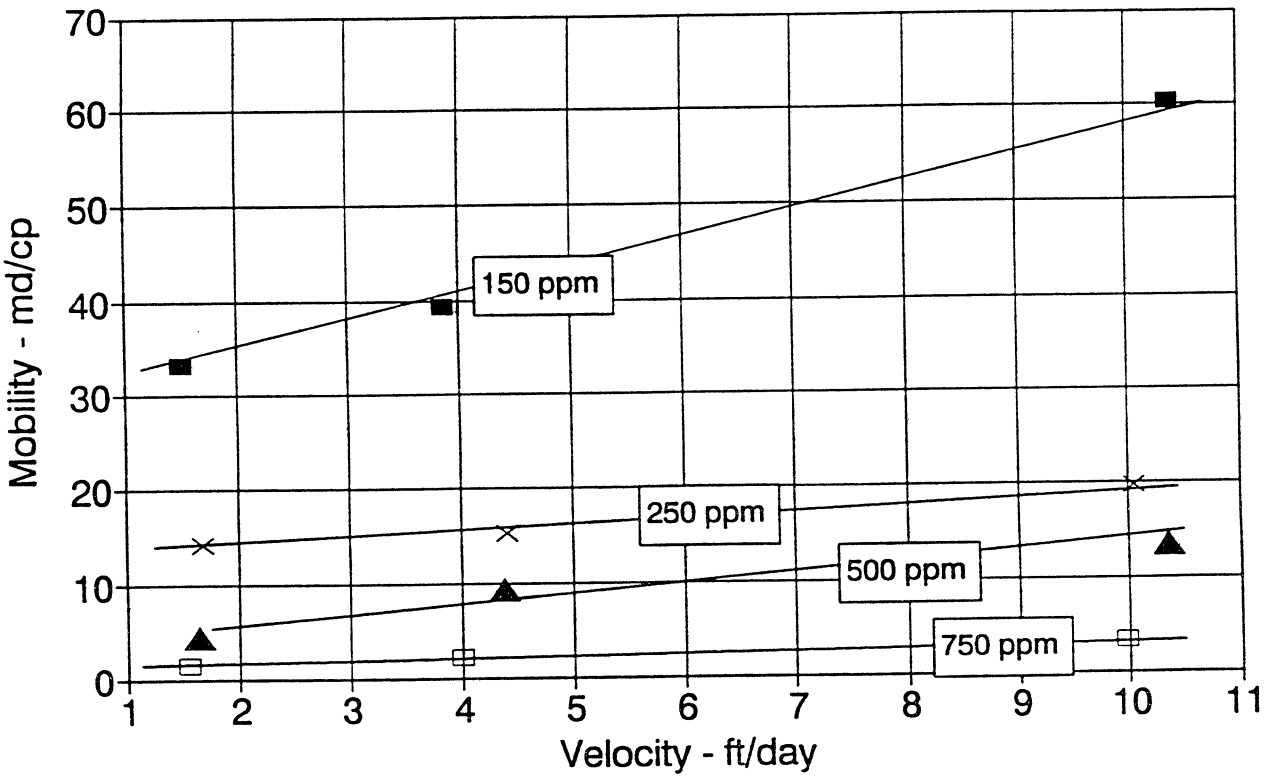

Figure 6. CO_2 foam mobility (CD–1045® in 640 md core).

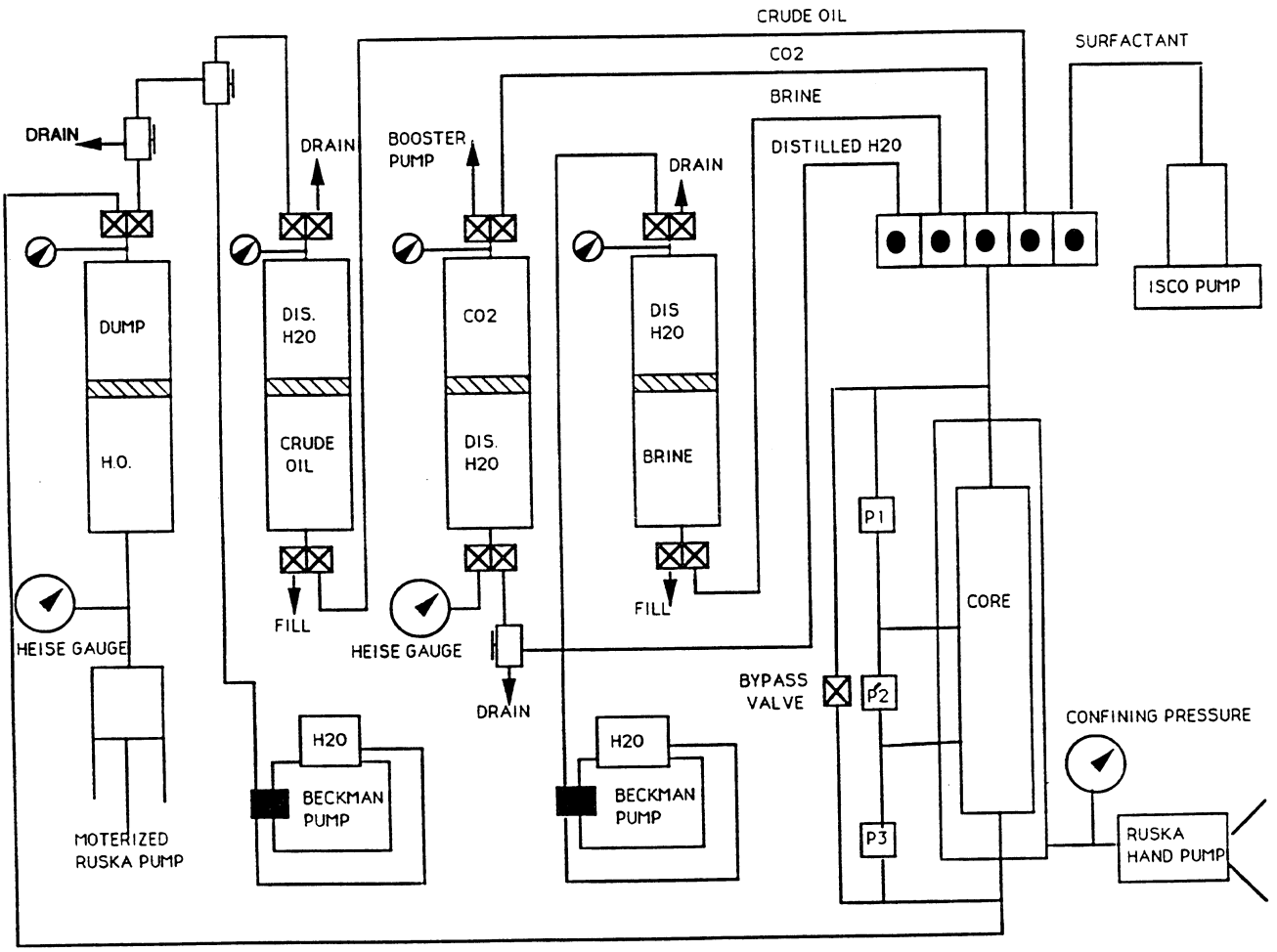

Figure 7. Foam test apparatus.

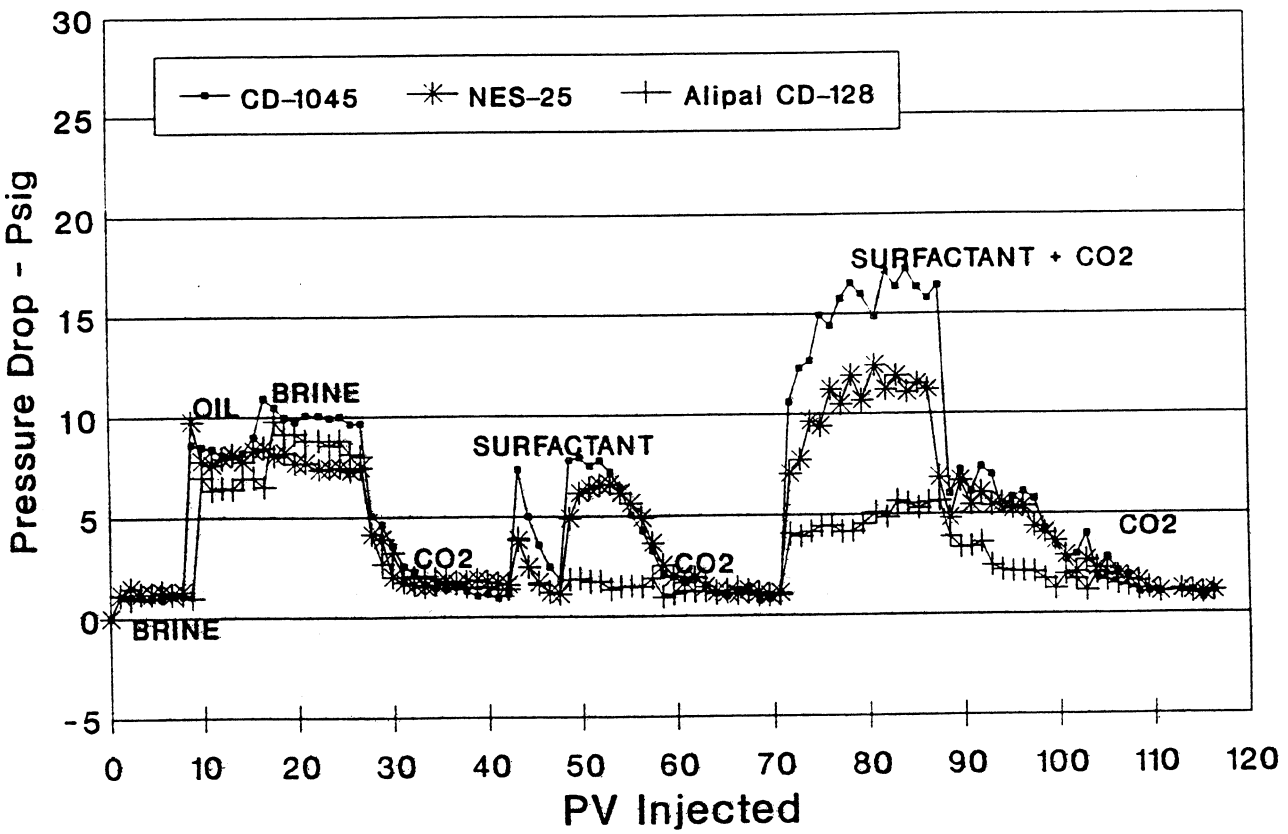

Figure 8. Foam test, 500 ppm active (brine perm=254 md).

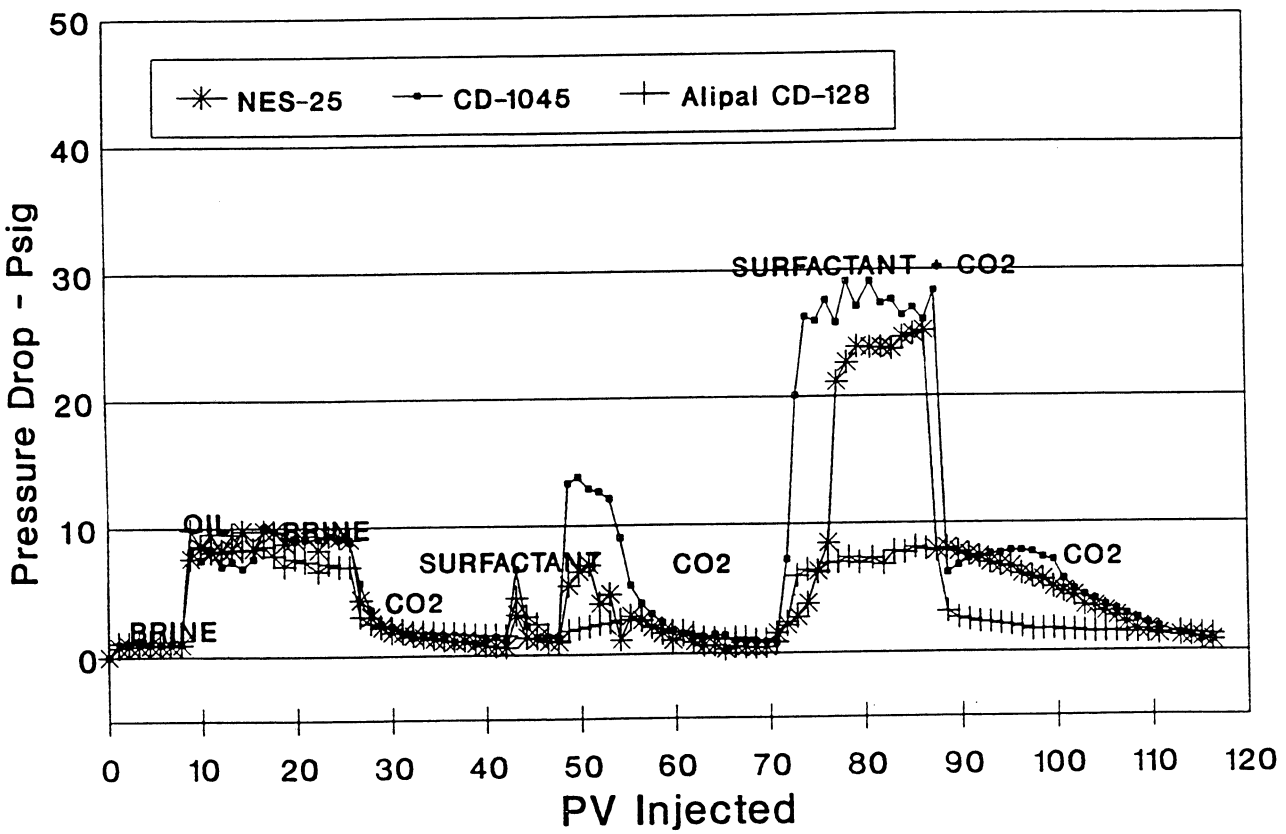

Figure 9. Foam test, 1000 ppm active (brine perm=254 md).

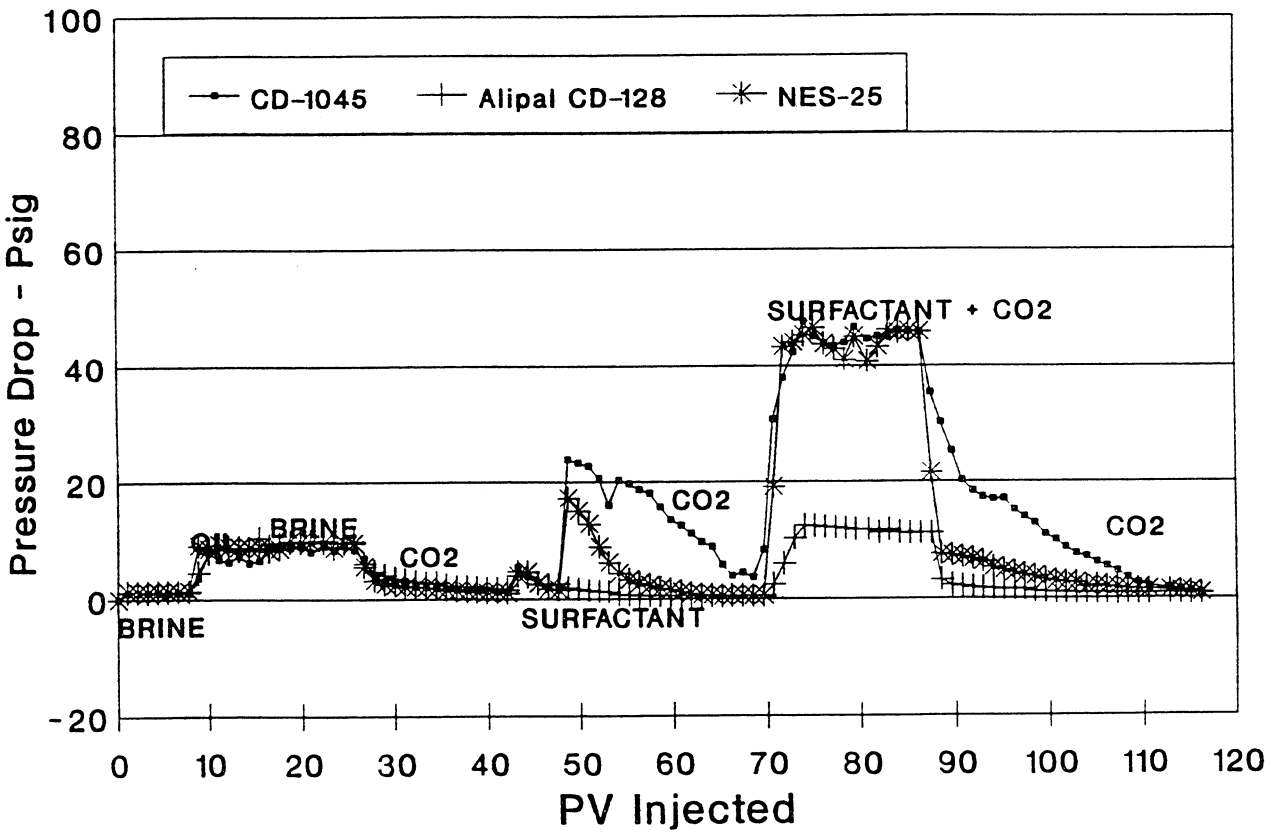

Figure 10. Foam test, 5000 ppm active (brine perm=254 md).

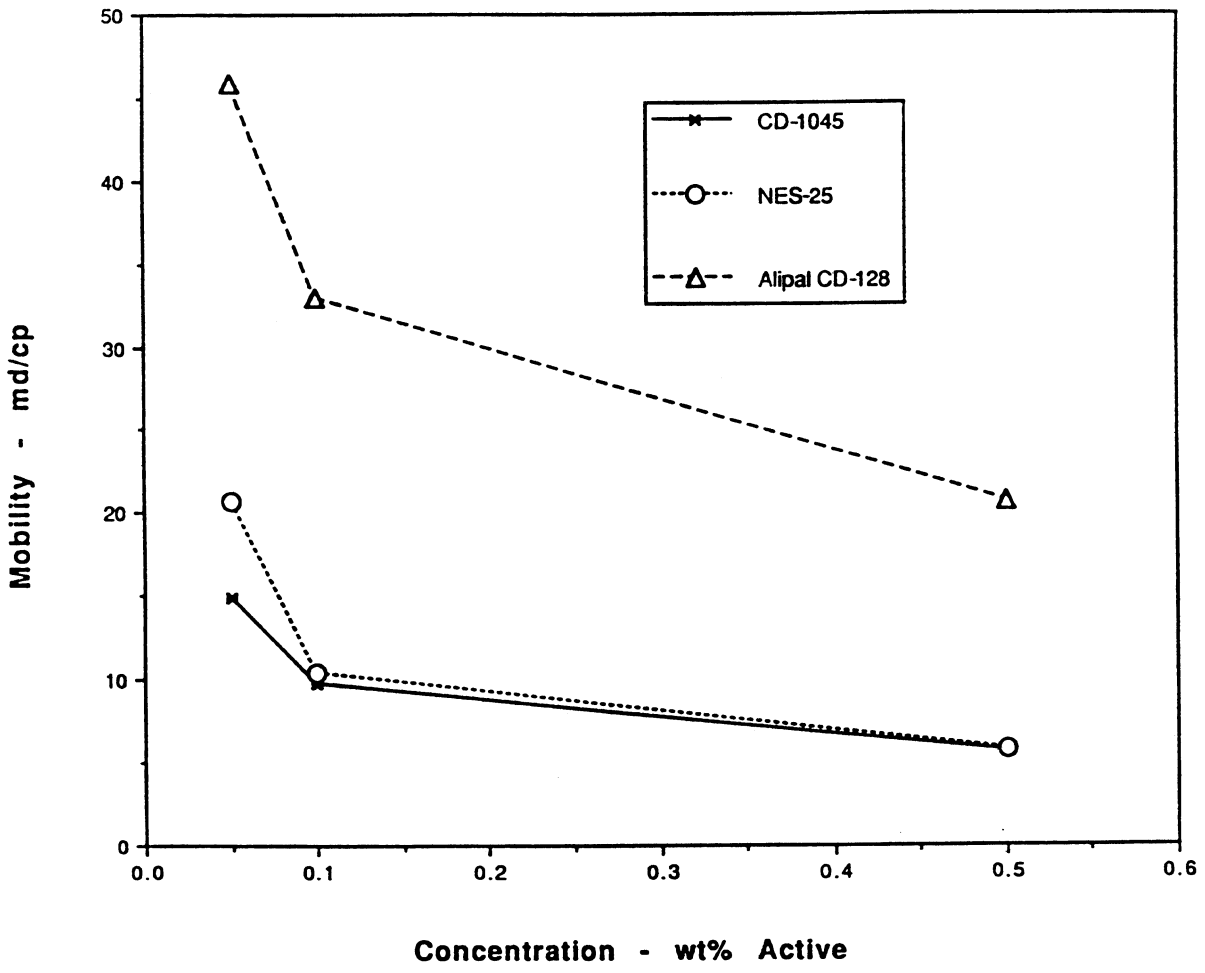

Figure 11. Mobility during coinjection of CO_2 and surfactant.

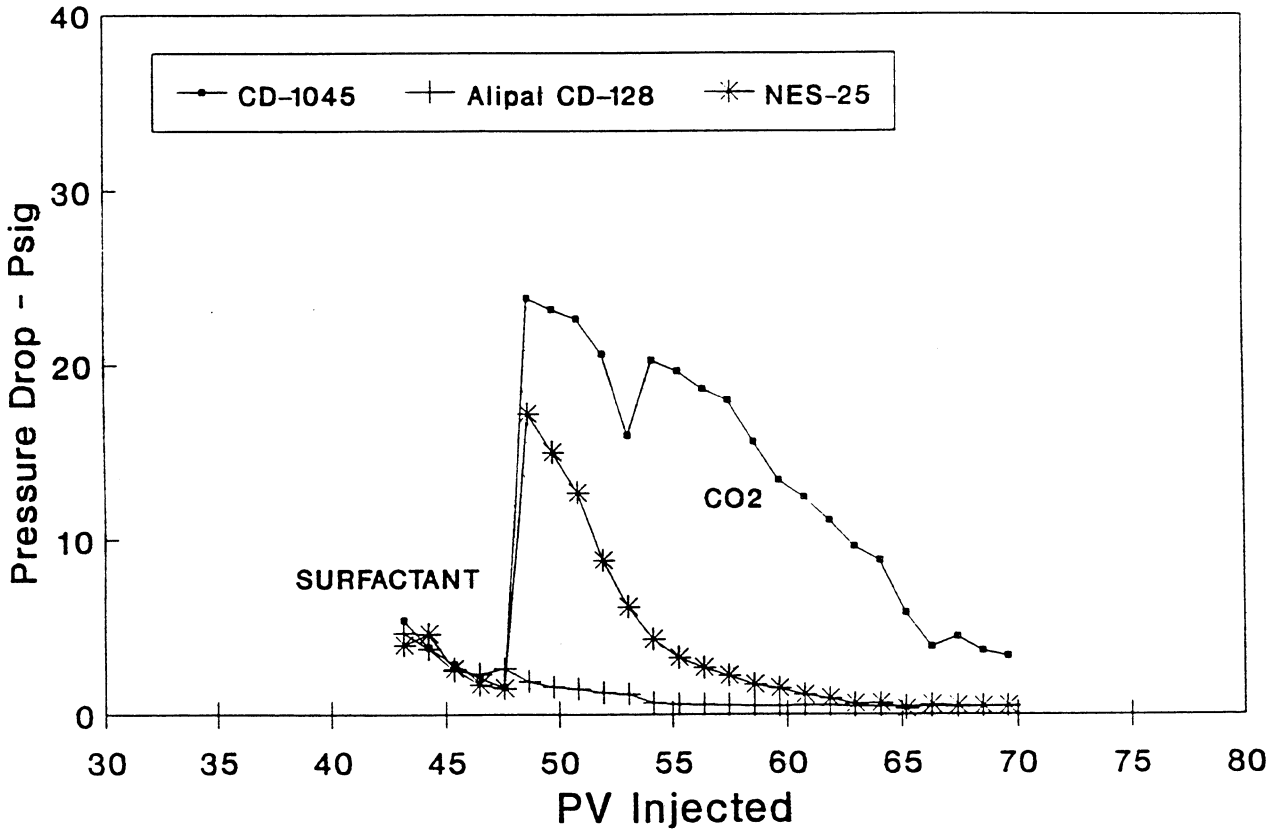

Figure 12. SAG process, 5000 ppm active (brine perm=254 md, 5000 ppm).

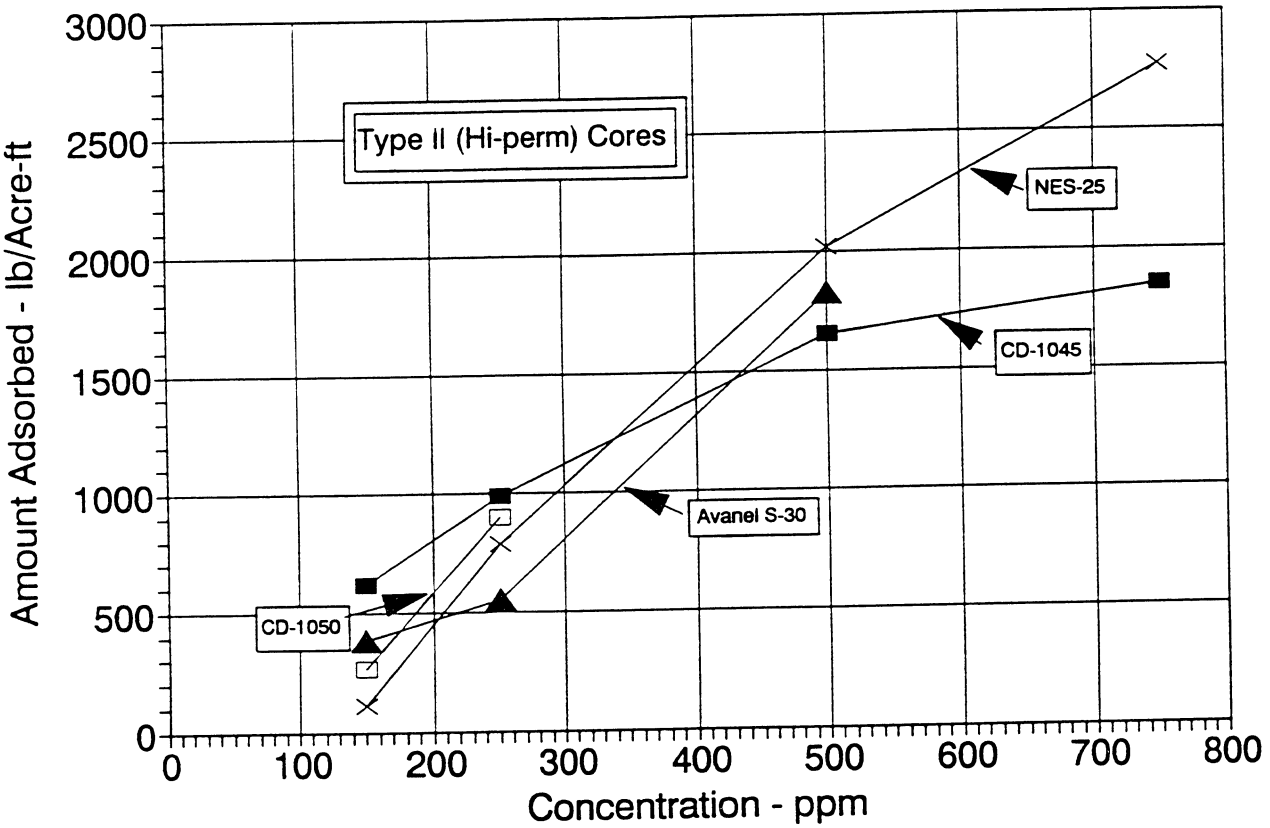

Figure 13. Surfactant adsorption (the dependence on slug size and flow rate).

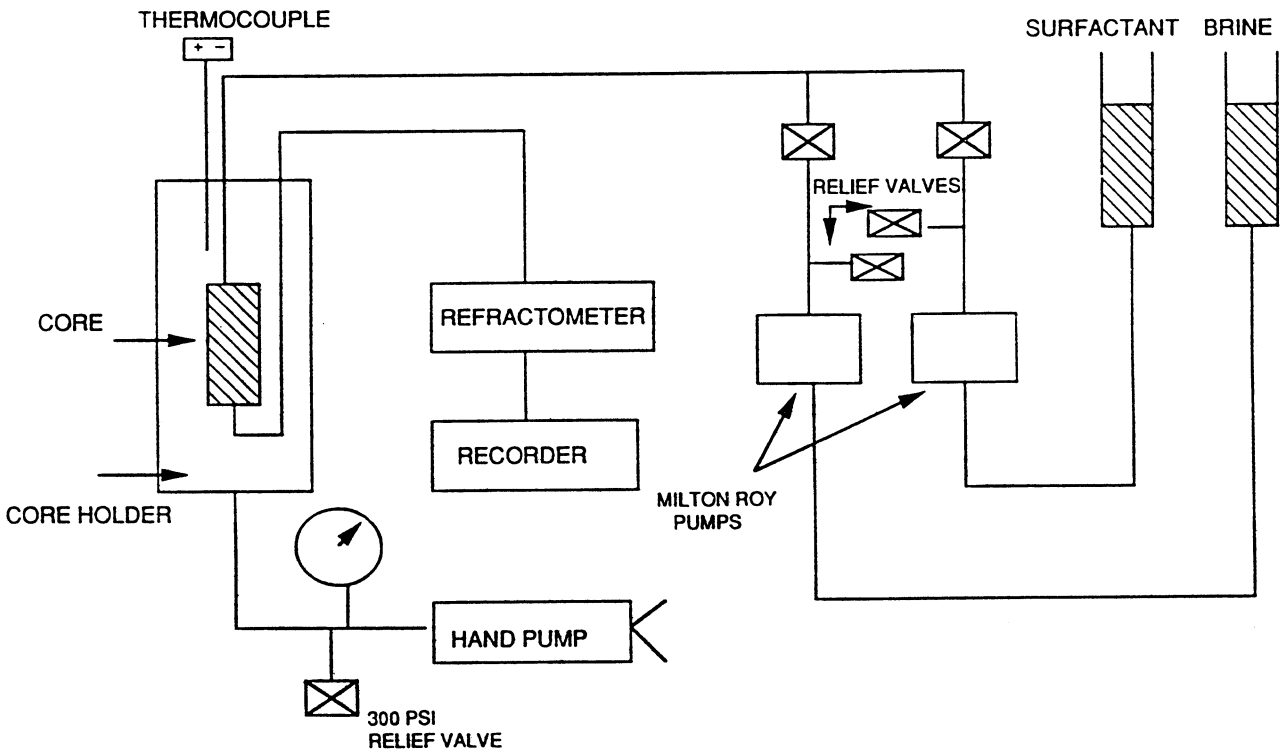

Figure 14. Apparatus for adsorption of CD-1045®.

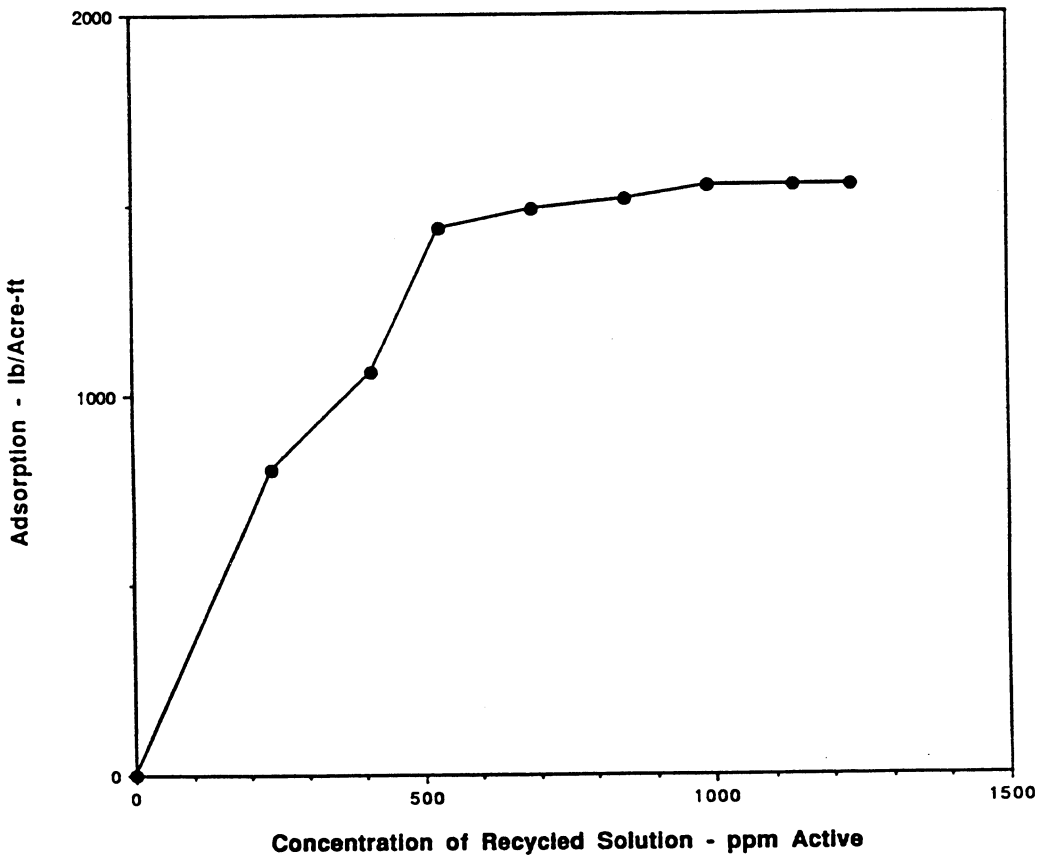

Figure 15. Adsorption of NES-25® on an EVGSAU rock.

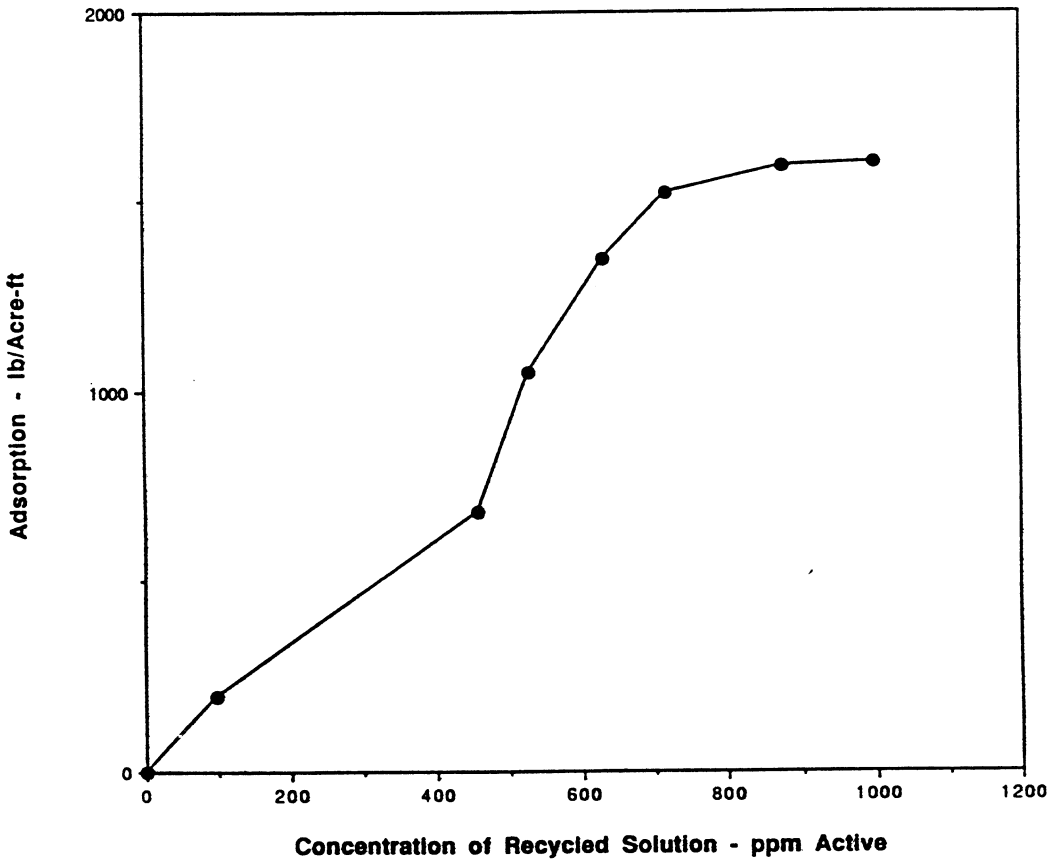

Figure 16. Adsorption of Alipal CD–128® on an EVGSAU rock.

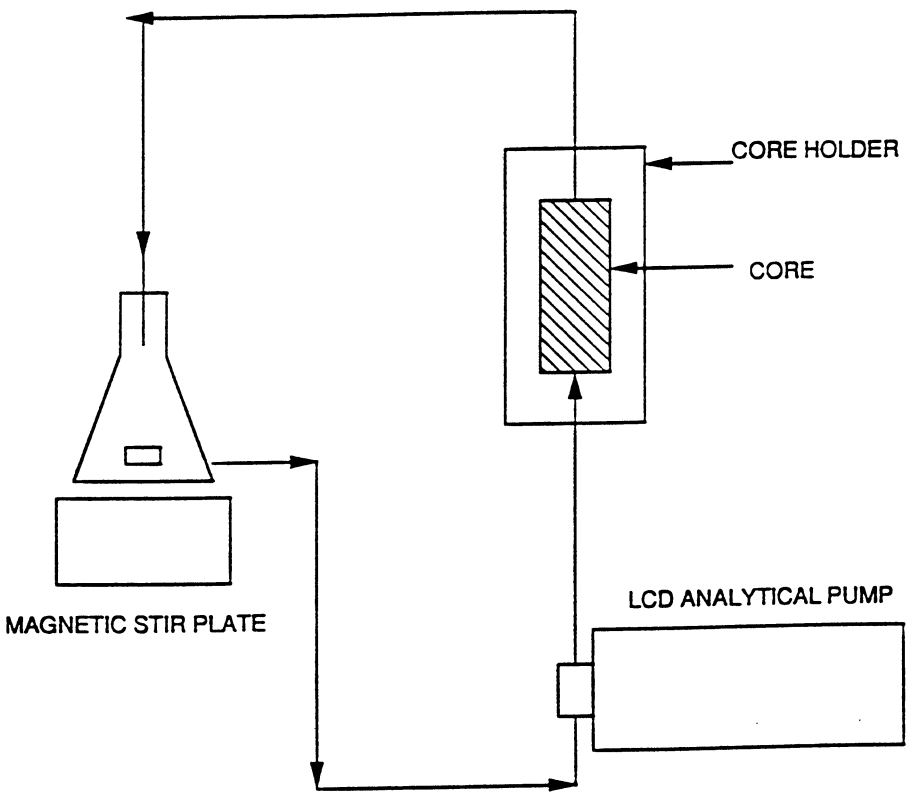

Figure 17. Recirculation method of adsorption testing.

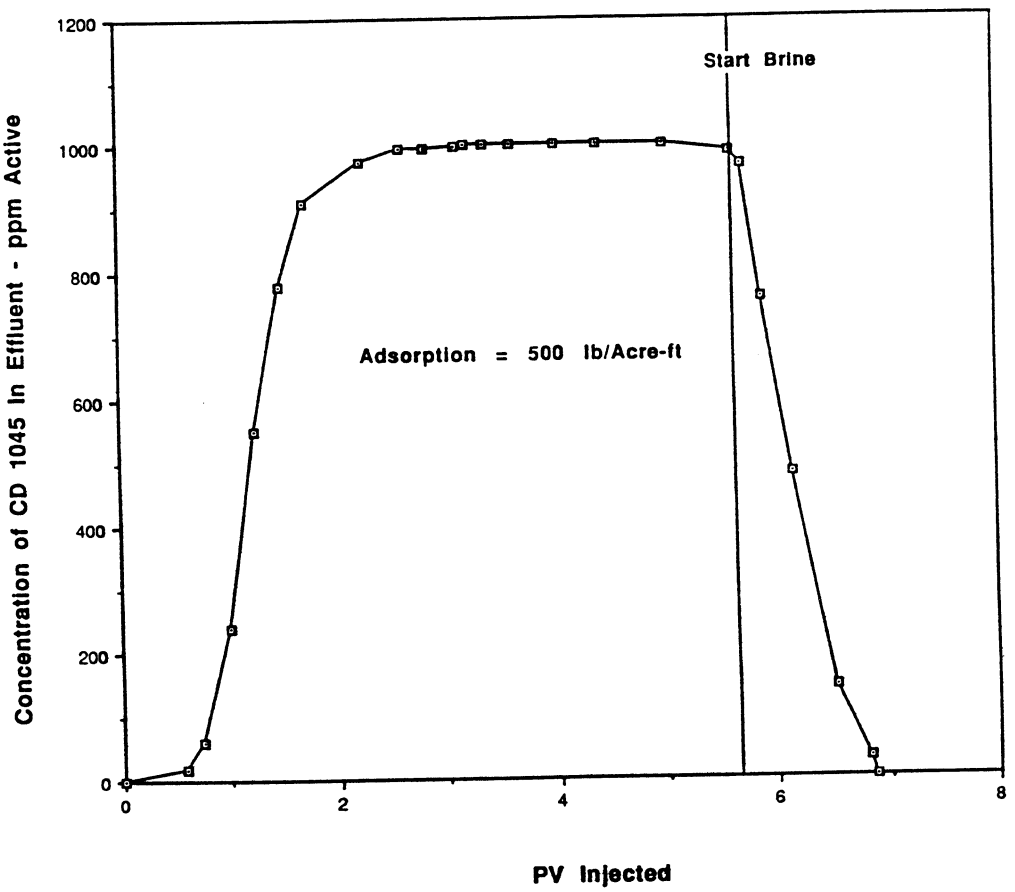

Figure 18. Adsorption of CD-1045® on an EVGSAU rock (perm=17 md, porosity=14%).

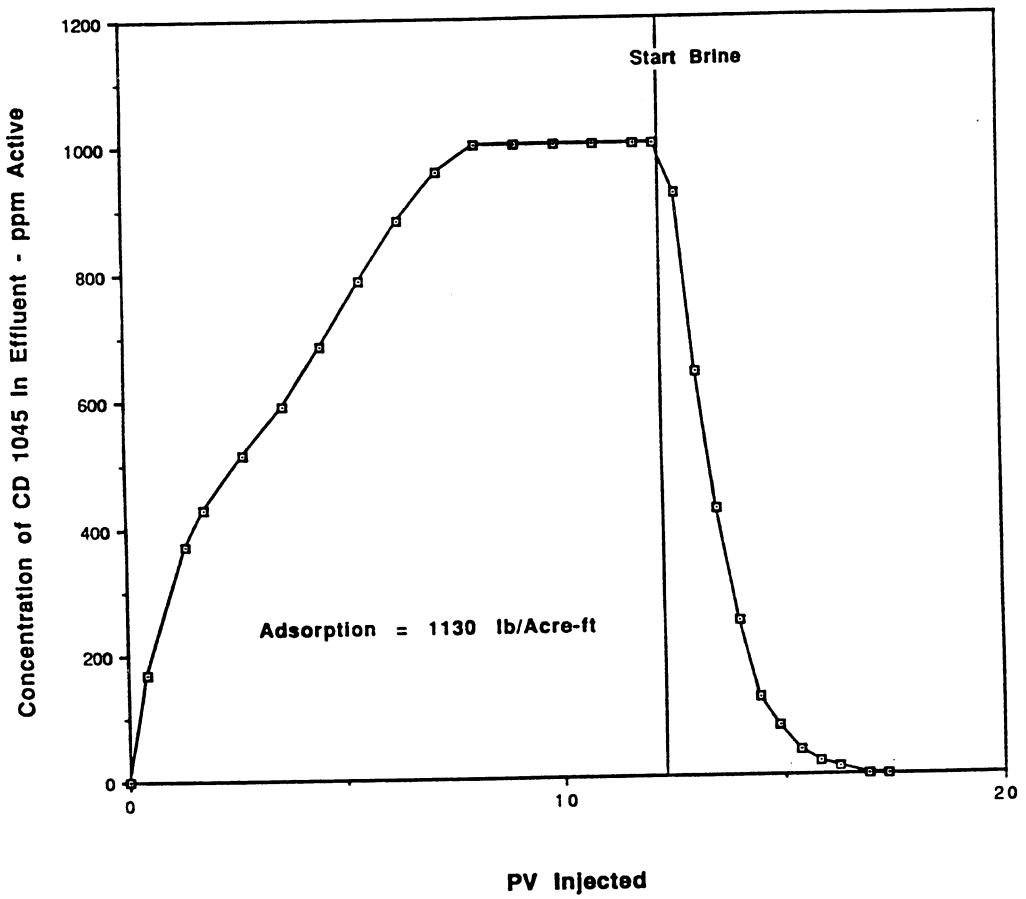

Figure 19. Adsorption of CD-1045® on an EVGSAU rock (perm=1.6 md, porosity=16.2%).

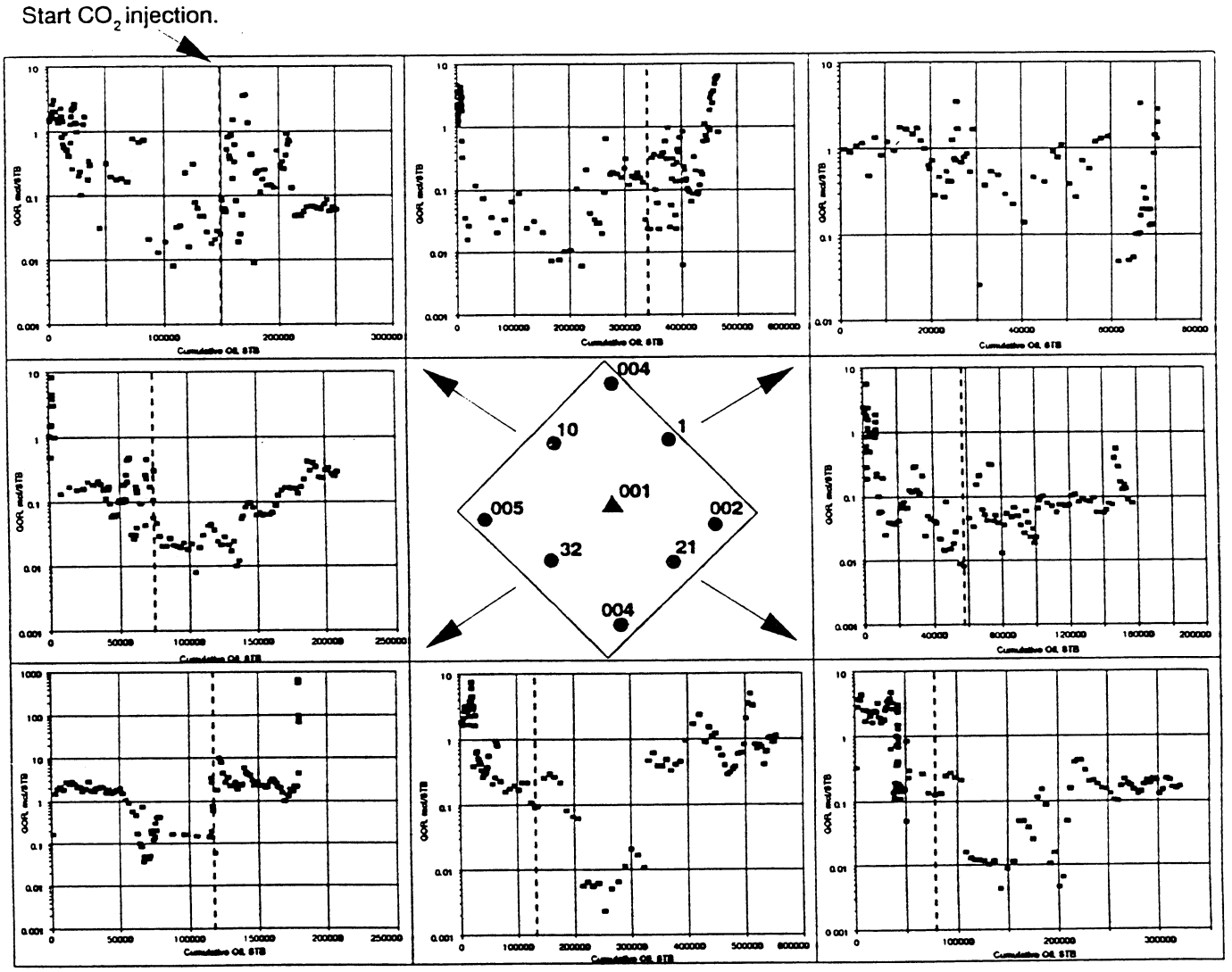

Figure 20. EVGSAU CO_2 foam pilot area production history since unitization.

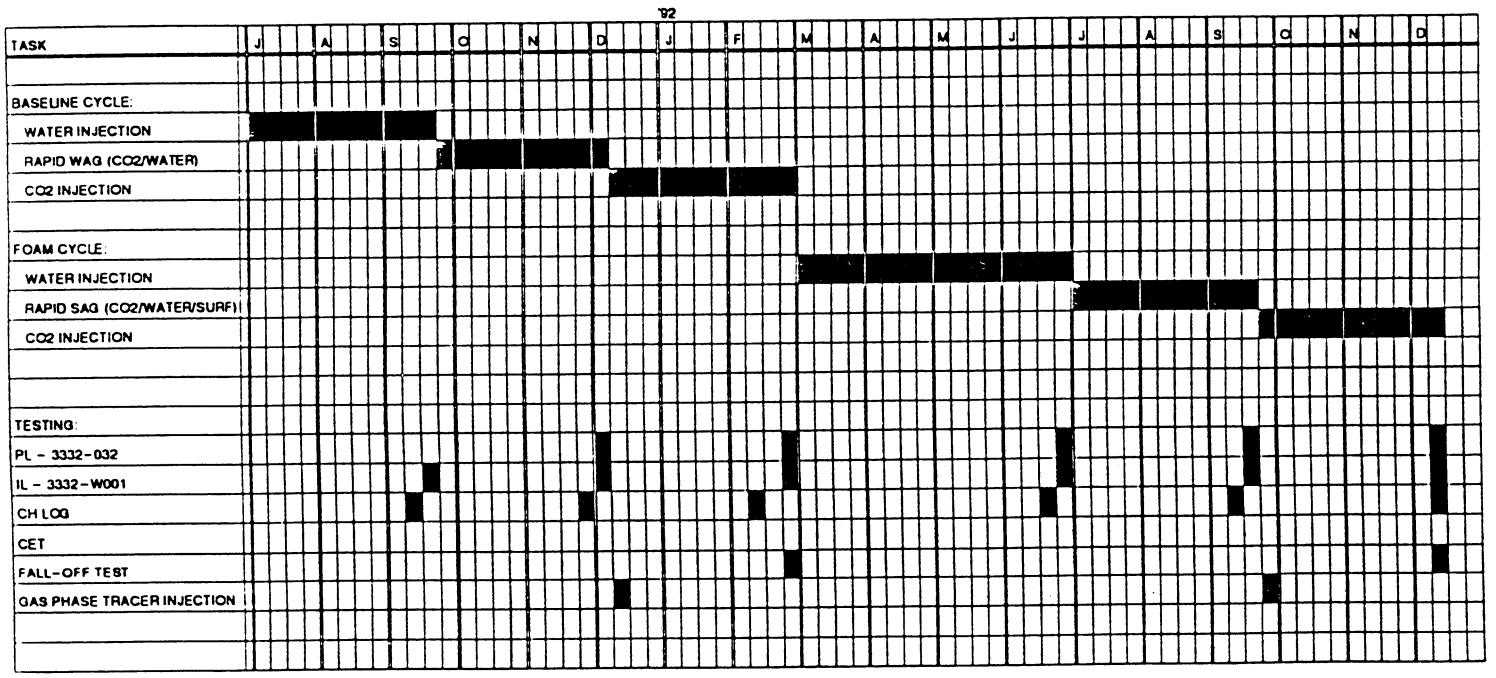

Figure 21. EVGSAU CO_2 foam project schedule (revised 12/17/91).

*U.S.GPO:1992-661-026/60022