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DESIGN AND IMPLEMENTATION OF A CO2 FLOOD UTILIZING ADVANCED RESERVOIR CHARACTERIZATION AND HORIZONTAL INJECTION WELLS IN A SHALLOW SHELF CARBONATE APPROACHING WATERFLOOD DEPLETION

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May 1997

Performed Under Contract No. DE-FC22-94BC14991

Phillips Petroleum Company
Odessa, Texas

National Petroleum Technology Office
U. S. DEPARTMENT OF ENERGY
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ABSTRACT

The work reported herein covers select tasks remaining in Budget Phase I and many of the tasks of Budget Phase II. The principal Tasks in Budget Phase I included in this report are Reservoir Analysis and Characterization; Advanced Technical Studies; and Technology Transfer, Reporting and Project Management Activities for Budget Phase I. The principle Task in Budget Phase II included in this report is Field Demonstration. Completion of these tasks has enabled an optimum carbon dioxide (CO_2) flood project to be designed, economically evaluated, and implemented in the field. Field implementation of the project commenced during late 1995, with actual CO_2 injection scheduled for start-up in mid-July, 1996.

The current project has focused on reducing initial investment cost by utilizing horizontal injection wells and concentrating the project in the best productivity area of the field. An innovative CO_2 purchase agreement (no take-or-pay provisions, CO_2 purchase price tied to West Texas Intermediate (WTI) crude oil price) and gas recycle agreements (expensing costs as opposed to a large upfront capital investment for compression) were negotiated to further improve the project economics.

The Grayburg-San Andres section had previously been divided into multiple zones based on the core study and gamma ray markers that correlate wells within the Unit. The type log for South Cowden Unit Well No. 8-19 is shown as Figure 1. Each zone was mapped as continuous across the field. Previous core studies concluded that the reservoir quality in the South Cowden Unit (SCU) is controlled primarily by the distribution of a bioturbated and diagenetically-altered rock type with a distinctive "chaotic" texture. The "chaotic" modifier is derived from the visual effect of pervasive, small-scale intermixing of tan oil-stained reservoir rock with tight gray non-reservoir rock. The "chaotic" reservoir rock extends from Zone C (4780'-4800') to the lower part of Zone F (4640'-4680'). Zones D (4755'-4780') and E (4680'-4755') are considered the main floodable zones, though Zone F is also productive and Zone C is productive above the oil-water contact.

The Stratamodel computer program was utilized as the primary tool to integrate the diverse geologic, petrophysical, and seismic data into a coherent three dimensional (3-D) model. The basic porosity model having been constructed, critiqued and modified based on field production and detailed cross-section displays, permeability data was imported into the model, and a 3-D interpolation of the permeability was completed.

A full-field reservoir simulation model had been constructed covering all of the South Cowden Unit plus Fina's Emmons Unit and a portion of Unocal's Moss Unit, both of which border SCU on the north. Visual inspection of the porosity and permeability distribution in the geologic model indicated that the E zone interval could be separated into four units. These four layers in the E, in addition to the F layer, upper D layer, and the C layer, comprise the seven flow units imported into the existing reservoir simulator to create a new,

more heterogeneous description. Data from five additional wells drilled in the project area under Phase II of the Project were also incorporated. The history match was updated, and a new simulation model run used to update CO_2 flood performance forecasts and to optimize final horizontal well locations, orientation, and completion strategy.

Several laboratory CO_2-foam experiments were performed in South Cowden Unit cores to select suitable surfactants for possible CO_2-foam application in the South Cowden Unit. Four surfactants, Chaser CD-1045, Chaser CD-1050, Foamer NES-25 and Rhodapex CD-128 were evaluated for their foaming ability. Chaser CD-1045 and Rhodapex CD-128 were selected for further testing after an initial screening. These surfactants were tested in co-injection as well as surfactant alternating gas (SAG) processes at various frontal velocities. The resulting foams exhibited Selective Mobility Reduction (higher resistance factor in higher permeability zones) as well as shear-thinning behavior. While average resistance factor for the foam produced in four sections of a field core was higher for the co-injection of Chaser CD-1045 than Rhodapex CD-128, the later surfactant performed better in the SAG process as well as exhibiting lower adsorption in Baker Dolomite cores.

Under Phase II of the project, one additional reservoir characterization well was drilled within the project area. Routine whole core analyses measurements were completed. The cores were slabbed for use in petrographic studies by Phillips' Bartlesville personnel, to include macroscopic core description and thin sections. Two vertical CO_2 water alternating gas (WAG) injection wells were drilled in December, 1995. The first was completed as a marginal oil producer, to be converted to CO_2 injection when the pipeline and injection facilities are completed, estimated in early July. The second well will also be completed at that time.

The drilling and completion operation for the horizontal CO_2 WAG injector Well 6C-25H began March 17, 1996, and was completed in 28 days. The drilling and completion operation for Well 7C-11H commenced April 14, 1996, and was completed in 20 days. The design parameters and the actual results matched exceptionally well. Water injection in these wells is anticipated to commence in early July, with CO_2 injection commencing in early August.

Petrographic core studies were commenced on cores obtained during the drilling of reservoir characterization well RC-3 (SCU Well 6-24). Burrow-mottled dolopackstones within the SCU reservoir interval are composed of gray, relatively low porosity and low permeability dolowackestone/dolopackstones and tan, oil-stained, porous and permeable dolopackstones/dolograinstones. The relative amounts of gray and tan dolomites composing the SCU reservoir interval greatly affect the reservoir porosity and permeability. The gray/tan percentages were compared with the same percentages similarly measured for four other SCU wells. Because reservoir porosity is also a function of anhydrite content, average anhydrite content of the tan dolomites along with average porosities were also determined from core analysis on all five wells.

EXECUTIVE SUMMARY

In June of 1994, Phillips Petroleum Company received a financial award from the Department of Energy to conduct a project in the South Cowden Unit in Ector County, Texas. The purpose of the project is to design an optimum carbon dioxide (CO_2) flood project utilizing advanced reservoir characterization and CO_2 horizontal injection wells, demonstrate the performance of this project in the field and transfer the information to the public so it can be used to avoid premature abandonment of other fields. The producibility problem in the unit is that it is a mature waterflood with a watercut exceeding 95%. Oil must be mobilized through the use of a miscible or near-miscible fluid in order to recover significant additional reserves. Also, because the unit is relatively small, it does not have the benefit of economies of scale inherent in the very large scale projects which have historically produced most of the CO_2 project oil. Thus, new and innovative methods are required to reduce the investment and operating costs. Two primary methods to be used in this work to accomplish improved economics are the use of reservoir characterization to restrict the flood to the high quality rock in the unit and the use of horizontal injection wells to cut investment and operating costs.

The project consists of two budget phases. Budget Phase I started in June, 1994 and ended late June, 1996. In this phase the Reservoir Analysis and Characterization Task and the Advanced Technology Definition Task were completed. Completion of these tasks enabled the project to be designed, evaluated, and an Authority for Expenditure (AFE) for project implementation to be generated and submitted to the working interest owners for approval. Budget Phase II consists of the implementation and execution of the project in the field. Phase II will terminate in January of 2001.

Budget Phase I was completed in late June, 1996, with the inclusion of geological and petrophysical interpretive data into a stratigraphic framework, which were then incorporated into the full-field simulation towards the evaluation of various combinations of horizontal and vertical CO_2 water alternating gas (WAG) injection wells. Preliminary studies were also conducted to investigate the effect of the CO_2 WAG injection strategy on project performance; a hybrid WAG injection scheme was determined to be the optimum project design. Performance forecasts were generated for the base case project development plan, with incremental oil forecasted at 10.4% of original oil in place (OOIP). The full-field simulator was also used to assess the effect of uncertainties in key input and operating parameters on the production profile and recoverable reserves for use in project risk analysis.

Budget Phase II commenced with the drilling of the third reservoir characterization (RC-3) during November and December, 1995. Well logs indicated greatly reduced porosity in the E and F zones, compared with offset wells. The well was perforated and tested 100% water, and was temporarily abandoned. Two vertical CO_2 WAG injection wells were drilled in December, 1995. The first was temporarily completed as a producing well, and will be converted to CO_2 injection when the pipeline and injection facilities are completed. The second well will be completed as a CO_2 injection well upon completion of the injection facilities and pipeline.

Two additional production wells were also drilled and completed in late 1995. These wells were needed to drain areas of the field offsetting the proposed horizontal injection wells, replacing old wells which had been previously plugged and abandoned.

Two horizontal CO_2 WAG injection wells were drilled and completed during March and April, 1996. The wells were designed to mechanically optimize well injection performance and useful well life.

Additional Phase II work commenced during the first half of 1996 included petrographic core studies on specific cores obtained during the drilling of the third Reservoir Characterization Well (RC-3).

INTRODUCTION

Summary of Project Objectives

The principal objective of this project is to demonstrate the economic viability and widespread applicability of an innovative reservoir management and carbon dioxide (CO_2) flood project development approach for improving CO_2 flood project economics in shallow shelf carbonate (SSC) reservoirs.

Most of the incremental tertiary oil production from CO_2 projects in SSC reservoirs to date has come from a few, very large-scale projects where the sizable economies of scale inherent in this type of development can greatly improve project economics. In fact, the five largest CO_2 miscible flood projects implemented in SSC reservoirs account for over one-half of the total incremental oil production attributable to CO_2 miscible flooding in 1992 in the United States.

This project shall demonstrate the economic viability of the advanced technology of developing a CO_2 flood project utilizing multiple horizontal CO_2 injection wells drilled in several directions from a central location. The use of several horizontal injection wells drilled from a centralized location will reduce the number and cost of new injection wells, wellheads, and equipment; allow concentration of the surface reinjection facilities; and minimize the costs associated with CO_2 distribution system. It is anticipated that the proposed advanced technology will show improved CO_2 sweep efficiency and will significantly reduce the capital investment required to implement a CO_2 tertiary recovery project relative to conventional CO_2 flood pattern developments using vertical injection wells. This technology will be readily transferred to the domestic oil industry and should introduce CO_2 flooding as an economically viable technology option for smaller SSC reservoirs and for independent operators.

Summary of Field Details

The South Cowden Unit is located in Ector County, Texas and produces primarily from the Grayburg and San Andres Formations of Permian Age. These formations were deposited in shallow carbonate shelf environments along the eastern margin of the Central Basin Platform. The primary target for CO_2 flood development under the proposed project is a 150-200 foot gross interval within the San Andres located at an average depth of approximately 4550 feet. The original oil in place for the South Cowden Unit is estimated to be less than 180 million barrels. The field was discovered in 1940 and unitized for secondary recovery operations beginning in 1965.

The Unit is currently near its economic limit, producing 342 BOPD at a watercut in excess of 95% from 42 active producers and 15 active water injectors. Ultimate recovery for primary plus secondary is estimated at just over 35 million STBO, or approximately 20 percent of OOIP. Tertiary oil resulting from the CO_2 project is estimated at 12 million STB, or 8% within the project area.

Project Description

The purpose of this project is to demonstrate the economic viability and widespread applicability of an innovative management plan for a CO_2 flood project, utilizing advanced reservoir characterization and CO_2 horizontal injection wells. The South Cowden Unit (SCU) is an example of a very mature waterflood, rapidly approaching its economic limit. Past waterflood performance was considered good; however, field average watercut at the project start-up exceeded 95 percent, leaving tertiary recovery as the only remaining prospect for extending the field life and recovering the remaining oil. Advanced reservoir characterization has been used to define the best areas within the field, which are likely to perform well under CO_2 operations.

Standard methods of CO_2 flooding are not viable under the current oil price scenario due to the limited aerial extent of the SCU. Standard methods include the traditional fully-confined nine- or five-spot patterns. In the case of SCU, a feasibility study was completed in which the field was CO_2 flooded with 20-acre five-spots (assumed because of the existing well configuration). The feasibility study indicated that the South Cowden Unit was an excellent technical CO_2 flood candidate; however, the large capital investment required restricted its economic viability. New and innovative methods were required to reduce the overall investment required to improve the economic viability. These new methods, however, carried additional risk.

The innovative approach chosen for the study was to CO_2 flood the South Cowden Unit with multiple horizontal injection wells from a centralized location. Preliminary studies indicated that significant investment cost reduction could be realized through lower overall drilling costs (fewer wells) and reduced surface injection line requirements, and operating costs reductions could be obtained through a reduction in re-injection costs. Improved sweep efficiency from the horizontal injection wells are expected to result in increased oil recoveries. Increased technical risks inherent in the project include the injection distribution along the horizontal section of the horizontal well and overall vertical coverage within the given horizontal well. Contingency plans for dealing with the technical risks were also developed. Advanced reservoir characterization has been essential in optimizing the final project design. At the conclusion of the project, a complete methodology for economical tertiary flooding of small SSC reservoirs will be established, allowing other operators to implement similar strategies for their own fields.

Summary of Progress

A CO_2 flood project for the South Cowden Unit (SCU) has been designed, evaluated, proposed to the working interest owners, approved for field implementation and partially implemented. Full-field implementation of the CO_2 project is projected in mid-July with the initiation of CO_2 injection.

Work on the project was initiated in June of 1994 with the Reservoir Analysis and Characterization Task, which were used to develop a three-dimensional (3-D) geologic reservoir description. An adequate reservoir description was assembled in early 1995 to initiate simulation studies for project design and performance forecasting.

The second major step in the process was defining the Advanced Technology Definition Task. This task was divided into seven subtasks, including Special Laboratory Studies; Screening Studies to Identify Suitable Gelled Polymers for Profile Modification; Advanced Geostatistical Studies; Reservoir Simulation for Project Design and Performance Forecasting; Design of the Horizontal Well Scheme and the Final Project Development Plan; Design of Upgrades and/or Additions to Production, Water Injection, CO_2 Injection, Compression, Water Disposal, Automation, Electrical and Cathodic Protection Facilities; and Investment Cost Forecast, Operating Cost Forecast and generation of the Authority for Expenditure (AFE). This AFE was approved and field implementation of the project (Budget Phase II) began in late October of 1995. From late October, 1995, through June 30, 1996, work included in Budget Phase I was being finished-up while implementation work included in Budget Phase II was being done.

Work on Budget Phase II was defined into two tasks: Field Demonstration and Technology Transfer, Reporting, and Project Management Activities for Budget Phase II. Field Demonstration encompasses the project implementation subtasks, to include drilling, testing, and completion of Reservoir Characterization Well RC-3; construction of the CO_2 distribution center; construction of the CO_2 recycle facilities; construction of the centralized production and gathering center facilities; drilling of the two horizontal wells; commencing water injection into the horizontal wells and performance monitoring; and the evaluation of project performance.

DISCUSSION

Background Information

Budget Period One consists of Tasks I-IV as defined in the Revised Statement of Work (RSOW) submitted March 8, 1996. The RSOW contains nine primary subtasks in Task I, Reservoir Analysis and Characterization. Final progress on all but Subtask I.1.9, Integrate Geological, Petrophysical, and Seismic Data into a three dimensional (3-D) Geologic Reservoir Description, was fully reported on in the Annual Report for the Period June 3, 1994 to October 31, 1995, finalized in May, 1996.

The RSOW contains seven primary subtasks in Task II, Advanced Technology Definition. Final work on the following Subtasks of Task II were not, however, completed by October 31, 1995, for inclusion in the previous Annual Report: Subtask II.1, Conduct Special Laboratory Studies; Subtask II.3, Reservoir Simulation Studies; and Subtask II.4, Horizontal Well Scheme and Finalize Project Development Plan..

The RSOW contains six primary subtasks in Task III, Technology Transfer, Reporting, and Project Management Activities for Budget Phase I. These activities continued through this annual reporting period.

The RSOW contains one major subtask in Task IV, Environmental Compliance. These activities continued through this annual reporting period, but are summarized in our quarterly Environmental Compliance reports.

Budget Period Two consists of Tasks V-VI as defined in the Revised Statement of Work (RSOW). The RSOW contains fourteen primary subtasks in Task V, some of which have been initiated and which will be reported on in this annual report. Task VI includes the identical activities contained in Task III; however, they should pertain to work completed during Budget Period Two.

TASK I: RESERVOIR ANALYSIS AND CHARACTERIZATION

Subtask 1.9 Integrate Geological, Petrophysical, and Seismic Data into a 3-D Geologic Reservoir Description

Permeability was computed for each well with digital log data using correlations to core permeability measurements and well production rates. This data was imported into the STRATAMODEL software, and a three dimensional (3-D) interpolation of the permeability distribution was completed. A three-dimensional porosity distribution had previously been completed for the model.

Visual inspection of the porosity and permeability distribution in the geologic model indicated that the E zone interval (the primary target for the carbon dioxide (CO_2) flood) could be separated into four units. These flow units are distinguished by small variations in porosity or permeability that are somewhat correlatable between wells. These four layers in the E, in addition to the F layer, upper D layer, and C layer, comprise the seven flow units in the reservoir simulation model.

Maps of structure, thickness, average porosity, and geometric average permeability were extracted from the geologic model for each of the seven simulation layers. Examples of the maps for the E1 layer are attached (Figures 2-5), which illustrate the dissimilarity between the porosity and permeability distribution in the field.

These data were imported to a reservoir simulator to create a new, more heterogeneous description. After updating the history match, the new description better matched individual well production performance, and provided a more reliable forecasting and reservoir monitoring tool. The new simulation model was used to optimize drilling locations for the horizontal injectors and other future wells in the field.

TASK II : ADVANCED TECHNOLOGY DEFINITION

Subtask II.1 Conduct Special Laboratory Studies

Subtask II.1.2 Conduct Coreflood Studies to Determine CO_2 Trapped Gas Saturation and Miscible Residual Oil Saturation

CO_2 relative permeability, trapped gas saturation, and hysteresis effects are key parameters in determining injectivity and displacement in a miscible CO_2 water alternating gas (WAG) injection project. In an effort to better understand CO_2 miscible WAG behavior in the South Cowden Unit, coreflood experiments were conducted on core samples from two major lithofacies within the project area. The data were used as key input parameters in reservoir simulation and project evaluation.

Core plugs used in the experiment were taken from native state cores drilled with a mud of neutral pH. The core plugs were divided into two major lithofacies groups: (1) a burrow-mottled dolopackstone "chaotic" facies and (2) a fusilinid dolowackestone "moldic" facies. The first lithofacies group is characterized by well-connected intergranular and intercrystalline porosity, while the second is seen as having poorly interconnected moldic porosity.

The pre-CO_2 waterflood injectivities in the two lithofacies were determined to be significantly different, as the second, fusilinid moldic facies was not amenable to a WAG process. Reservoir parameters, essential to high-quality reservoir modeling, were measured and input into the SCU reservoir simulation. These included maximum (endpoint) CO_2 relative permeabilities and corresponding residual oil saturations; trapped gas saturations;

and measured relative permeability hysteresis effects.

Incorporation of the water relative permeability hysterisis effects into the simulation runs resulted in a more rapid production response and higher incremental oil recovery than previously projected. Application of the lower (measured) CO_2 relative permeabilities resulted in significantly reduced CO_2 injection rates, later gas breakthrough, less produced gas, and higher incremental oil recovery.[1]

Subtask II.1.4 Laboratory Corefloods to Identify Potential Foaming Surfactants for CO_2 Mobility Control

The objective of this study was to screen four surfactants to identify the best candidate as a contingency plan for possible CO_2-foam application at the South Cowden Unit following CO_2 flood. Four surfactants, Chaser CD-1045 and Chaser CD-1050 obtained from Chaser International, Rhodapex CD-128 provided by Rhone-Poulenc and Foamer NES-25 obtained from Henkel Corporation, were evaluated. Since this was a comparative study, it would have been necessary to use identical cores to evaluate the foaming ability of the surfactants. However, due to a severe inhomogeneity of the South Cowden Unit cores, identical tests performed in a single field core would have been the next choice. Initial CO_2-foam tests performed in a South Cowden Unit core showed that front end of the core would collapse within 2-3 core tests due to dissolution of softer parts of the core. To avoid this problem a short South Cowden Unit core was placed upstream of the test core. This provision extended the life of the test core so that all four surfactants could be tested in the same test core. The goal of these initial studies was to select the best two surfactants for further testing for selection of the best candidate for CO_2-foam applications at the South Cowden Unit. The follow-up studies included evaluation of the effect of surfactant concentration, frontal velocity, comparisons of co-injection versus Surfactant Alternating with Gas (SAG) processes, and determination of surfactant adsorption in cores with no oil or cores at residual oil saturation. All surfactant solutions used in these studies were prepared in Synthetic South Cowden Unit Brine. Analysis of this brine is given in Table 1.

CO_2-Foam Test Setup and Flooding Procedure

All CO_2-foam flooding experiments were performed at the reservoir temperature of 98° F under 2000 psi of pressure. Figure 6 shows a schematic diagram for the setup used in evaluating the foaming ability of various surfactants. Core 12A, a South Cowden Unit core used to rank the four surfactants in their foaming ability, was 1" in diameter and 4.84" in length. This core, which was equipped with three pressure taps along its length, was epoxy coated and connected down stream of another South Cowden Unit core (pre-foamer 10C), 1" in diameter and 2" in length, also epoxy coated. Both cores were placed in a core holder and pressurized to a confining pressure of about 2200 psi using a Ruska hand pump. An Isco Model 500D Syringe Pump was used to inject the surfactant solution into the core, while a motorized Ruska pump operated in withdrawal mode controlled the total flow rate. CO_2 flow rate was controlled by the difference between the total flow rate and the surfactant flow rate. A second Isco Model 500D Syringe Pump, depicted in the upper left corner of Figure 6 operated in withdrawal mode was programmed for frontal velocity and SAG (Surfactant Alternating with Gas) studies. A Beckman Model 100A pump shown on the upper right corner of Figure 6 was used to control the foam test under 2000 psi constant upstream pressure through oil, CO_2 and brine cylinders. A selector valve not shown in this figure was programmed to flow either CO_2 or surfactant solution at preset schedules. This setup is highly automated and was operated around the clock without the need for operator's presence.

Initial Screening and Determination of Optimum Foam Quality

Figure 7 shows a plot of Resistance Factor (RF) versus time in the four sections of the core for the CO_2-foam produced with 2000 ppm Chaser CD-1050 at various foam qualities. RF values were calculated from Equation 1 listed below.

$$RF = (Q/\text{ª}P)_{Brine}/(Q/\text{ª}P)_{Foam} \qquad (1)$$

Where, Q is the flow rate and ªP represents the pressure drop in a given section of the core. As this figure shows, RF values calculated for each section of the core appear to depend on the permeability of that section. For example section 1 of this core with a permeability of 551.5 md reached an equilibrium RF value of 265 at 20% foam quality, while section 4 with a permeability of 32.8 md exhibited an RF value of 18.7 at the same foam quality. The phenomenon of higher RF values encountered in the higher permeability cores is known as Selective Mobility Reduction observed in the literatures[2-4]. Figure 8 summarizes RF values for the four sections of the same core (Test Core 12A) as a function of foam quality. This plot further shows that RF value varies with the permeability of that section at all foam qualities. This plot also shows that 70% foam quality (70% CO_2) produces the highest RF values for each section of the core. Figure 9 shows similar results for the CO_2-foam produced with 2000 ppm Chaser CD-1045 in Test Core 12A. Comparing Figures 8 and 9 indicates that the permeability of Test Core 12A used in both tests changed from test to test. The permeabilities listed in these plots represent the values measured at the beginning of each test used to arrive at the RF values in that test. Figures 10 and 11 summarize the results for CO_2-foams produced with 2000 ppm Foamer NES-25 or 2000 ppm Rhodapex CD-128 in Test Core 12A. While optimum foam quality for Foamer NES-25 is between 50% - 60%, optimum foam quality for Rhodapex CD-128 is about 70%.

Figure 12 shows a composite plot for the average RF for the four sections of the Test Core 12A versus foam quality for all surfactants tested at 2000 ppm level. As this plot shows, Rhodapex CD-128 and Chaser CD-1050 produced the highest average RF values followed by Chaser CD-1045 and Foamer NES-25. However, based on previous field experience and sensitivity of Chaser CD-1050 to oil, Chaser CD-1045 was selected as one of the two surfactants to be tested in the next phase. The other surfactant selected for further testing was Rhodapex CD-128.

Effect of Frontal Velocity on CO_2-foam

Figure 13 shows a plot of RF versus time for CO_2-foam produced with 2500 ppm Rhodapex CD-128 at frontal velocities of 2.2 to 17.8 ft/day in the four sections of Test Core 10B. It is apparent from this plot that CO_2-foam is exhibiting a shear thinning behavior. This plot also shows that RF values increase with permeability of the core.

Figure 14 shows a plot of average RF versus frontal velocity for the foams (70% quality) produced with Rhodapex CD-128 at various concentrations. This plot shows a shear thinning behavior for the CO_2-foams produced with Rhodapex CD-128. While the points in this plot represent the measured values, the lines represent exponential fit of the data with listed R^2 values close to 1 indicating a good fit. Figure 15 shows similar results for CO_2-foams produced with Chaser CD-1045 at various concentrations and 70% foam quality. This plot also shows a shear thinning behavior for Chaser CD-1045. Comparing the RF values from Figures 14 and 15 at a given frontal velocity and surfactant concentration shows that Chaser CD-1045 produces better foam than Rhodapex CD-128 in the co-injection of surfactant and CO_2.

Surfactant Alternating with Gas (SAG) Process

Since optimum foam quality for Chaser CD-1045 and Rhodapex CD-128 was determined to be 70%, this value was selected for several SAG experiments performed with these surfactants. Figure 16 summarizes the RF values versus time for frontal velocities in the range of 2.2 to 17.8 ft/day for the foam produced with 2500 ppm Chaser CD-1045. The slug size, the sum of surfactant and CO_2 in each sequence, was 1/3 of the total pore volumes for the test core and the pre-foamer core. This plot once again shows a shear thinning behavior for the CO_2-foam produced.

Figure 17 shows a plot of average RF for the four sections of the core versus frontal velocity for the foams produced with Chaser CD-1045 at 1/3 PV, 70% foam quality and various surfactant concentrations. This plot shows that RF value is a function of surfactant concentration. This plot also shows a shear thinning behavior for these foams. The data points in this plot represent the average of RF values for the four sections of the test core while the lines represent the exponential fits to these points with R Squared (R^2) values given. R Squared indicates how closely the surfactant concentration and RF values are correlated, or how much variation in the RF value can be explained by the surfactant concentration. The value of R^2 is defined as being between 0 and 1. The closer the R^2 value is to 1, the more closely the surfactant concentration is related to the RF value.

Figure 18 shows a comparison between the average RF for the four sections of the test core for the foams produced by the co-injection of 2500 ppm Chaser CD-1045 at 70% foam quality and SAG processes at 2500 ppm Chaser CD-1045 at 1/3 to 3/3 pore volumes. As this plot shows, the best performance is obtained for the co-injection process as compared to the SAG process, and that performance of the SAG process degrades with the size of the slug. Figure 19 compares the average RF for the four sections of the test core versus frontal velocity for the foams produced at various surfactant concentrations. This plot indicates that the performance of the foams produced by the SAG process is a function of surfactant concentration.

Figure 20 compares the performance of the foams produced by co-injection and the SAG processes for 2500 ppm Rhodapex CD-128. As this plot shows the average RF for the four sections of the core decreases with frontal velocity. This plot also shows that best performance is obtained by the co-injection process and the average RF decreases with the slug size in the SAG process.

Effect of Residual Oil on Performance of CO_2-Foams

To evaluate the sensitivity of CO_2-Foams produced with selected surfactants to residual oil, several flooding experiments were performed in a test core at residual oil saturation. Figure 21 shows a comparison for average RF versus time for foams produced with 2500 ppm Chaser CD-1045 or 2500 ppm Rhodapex CD-128 in Test Core 12A at residual oil saturation at a broad range of foam qualities. As this plot shows, Rhodapex CD-128 produced a higher average RF for all foam qualities tested.

Surfactant Adsorption Studies

Earlier adsorption tests performed with various surfactants in the South Cowden Unit field cores indicated a strong dependency of adsorption value on core porosity[5] rather than the surfactant type. However, due to a severe inhomogeneity of these cores, Baker Dolomite cores were chosen for surfactant adsorption tests to rank the best two surfactants identified through foam tests in the South Cowden Unit cores. Baker Dolomite cores used in this study were typically 1.5" in diameter, 3" in length with an average porosity of 20.1% and pore volumes of about 17.3 ml.. In each test about 30 mg (0.5 - 1.7 pore volume slugs) of a given surfactant was injected into the core at 1000, 2000, or 3000 ppm. Surfactant concentration in the core effluents was monitored by refractive index measurements during each test. Each surfactant slug was flushed with synthetic South Cowden Unit Brine to a total volume of 10 PV. Figure 22 is a plot of surfactant concentration versus mass for the injection of 10 grams of 3000 ppm Chaser CD-1045 showing the injected and recovered surfactant monitored by refractive index measurements. Each division on the X-axis represents one pore volume of core effluent. Figure 23 shows a replot of this data in terms of cumulative amount of surfactant versus mass. As this plot indicates, most of the surfactant is recovered within the first four pore volumes of the core effluents, reaching its maximum by the sixth pore volume. Figures 24 and 25 represent adsorption data for the injection of 10 grams of 3011.3 ppm Rhodapex CD-128 in a Baker Dolomite core monitored by refractive index measurements. As these plots indicate, Rhodapex CD-128 adsorbs at a lower rate than Chaser CD-1045. In addition to continuous refractive index measurements carried out during surfactant injection and brine flush, surfactant concentration was also measured at a single point for the 10-PV core effluent using total organic carbon determination and hyamine titration.

Thirteen adsorption tests were performed with solutions of Chaser CD-1045 and Rhodapex CD-128 in synthetic South Cowden Unit brine. Table 2 summarizes the results for these tests. While the magnitude of the adsorption values measured by refractive index (RI), total organic carbon (TOC) and hyamine titration (HT) do not match very closely (Table 2), they follow a trend. We chose to average the values determined by the three techniques for all concentrations tested. The average surfactant adsorption for Rhodapex CD-128 and Chaser CD-1045 calculated for all concentrations and the three techniques were 99.8 and 420.9 lbs/acre-ft, respectively. The average surfactant adsorption for Chaser CD-1045 in cores at residual oil saturation for three surfactant concentrations measured with the techniques listed above was calculated to be 557.3 lbs/acre-ft with an increase of about 32% over the tests performed in the absence of oil.

In an effort to identify a suitable sacrificial agent to reduce the adsorption of Chaser CD-1045, we evaluated the use of hydroxyethyl cellulose at 250 ppm. After circulating a 1-liter solution of 250 ppm HEC-25 in synthetic South Cowden Brine for several days to reach equilibrium, as monitored by the refractometer, we used the equilibrated brine to prepare a 2970.8 ppm Chaser CD-1045. Adsorption results for solution measured by refractive index and hyamine titration averaged to 446.6 lbs/acre-ft which is not lower than the average of 420.9 lbs/acre-ft calculated for this surfactant in cores with no oil in the absence of sacrificial agent. Unlike lower adsorption observed for propoxy-ethoxy glyceryl sulfonate reported elsewhere[6] in presence of 1250 ppm HEC in a sandstone core, this product does not appear to reduce the adsorption of Chaser CD-1045 in a dolomite core.

Also listed in Table 2 is the adsorption results for the injection of 29.97 mg of Rhodapex CD-128 in a Baker Dolomite core with an average adsorption of 149.9 lbs/acre-ft. This test was followed with the injection of 29.92 mg of Chaser CD-1045 in the same core, resulting in an average adsorption of 489.9 lbs/acre-ft. These results indicate that the use of Rhodapex CD-128 ahead of Chaser CD-1045 does not decrease the adsorption of the latter surfactant.

Subtask II.3 Conduct Reservoir Simulation Studies for Project Design and Performance Forecasting

Full-field simulation runs were completed to evaluate various combinations of horizontal and vertical CO_2 WAG injection wells for the South Cowden project. The most effective well configuration for South Cowden was determined to be one in which horizontal CO_2 WAG injectors are positioned in down-structure locations (oriented approximately parallel to structural strike) in combination with vertical WAG injection wells in structurally higher locations. The simulation runs indicated that vertical permeability restrictions in the lower portion of the main reservoir interval would limit the vertical distribution of injected CO_2 into the lower intervals if only horizontal injection wells were used. Application of horizontal CO_2 injection wells was indicated to be most effective in those down-structure locations where much of the reservoir pore volume in the more isolated lower intervals lies below the original oil-water contact.

The South Cowden full-field simulation model was expanded and updated to accommodate revised reservoir description information which was obtained from: (a) inclusion of data from five additional wells drilled in the project area, and (b) improvements in delineating the porosity and permeability distribution in the project area. Significant improvement in delineating the permeability distribution in the South Cowden reservoir was obtained by integrating production performance data into the 3-D geological modeling. The updated geologic model indicated that the main reservoir interval (Zone E) should be divided into four subunits (vs. the original division into three subunits) to better reflect the porosity and permeability structure within Zone E. The resulting simulation model grid required to accommodate the updated geologic model was 54X54X7 (20,412 active cells). The revised field performance history match obtained using the updated geologic model resulted in significant improvements in individual well performance matches.

The revised simulation model was then used to update CO_2 flood performance forecasts and to optimize final horizontal well locations, orientation, and completion strategy. Based on the updated performance forecasts, the western horizontal well (SCU 7C-11H) was reoriented to better conform to local reservoir quality trends. The simulation model forecasts indicated this should result in more rapid production response to CO_2 injection. The updated project performance forecasts were also used to aid in final design of surface facilities and to finalize well conversion and workover strategies prior to implementation of CO_2 injection. The estimated incremental oil recovery for the South Cowden CO_2 project is expected to be about 10.4% of the original oil in place (OOIP).

Simulation modeling was also used to assess the effect of uncertainties in key input and operating parameters on production profiles and recoverable reserves for use in project risk analysis. Major elements of uncertainty having the largest impact on performance forecasts were identified by the project team. These grouped into three major categories - reservoir characterization/heterogeneity/sweep efficiency; CO_2 process efficiency/target oil volume; and well completion efficiency/injectivity (with the greatest focus on horizontal well completion effectiveness). It is expected that project performance forecasts will need to be updated as implementation proceeds and data on actual injectivity and flood response are obtained. The need for and final locations for additional wells will be determined based on observed flood response and updated simulation model forecasts.

A number of sensitivity runs were made with the simulation model to investigate the effects of CO_2 injection strategy on project performance. Incremental oil recovery vs. WAG ratio results from these simulations showed that some mobility control would be needed to optimize recovery efficiency after CO_2 breakthrough. A small amount of water injection alternating with CO_2 produced significant increases in oil recovery efficiency compared with continuous CO_2 injection. Subsequent increases in WAG ratios produced much smaller increases in oil recovery. While the maximum oil recovery was obtained at a WAG ratio of approximately 2:1, the time required to inject a given total volume of CO_2 was significantly longer at this high WAG ratio. A variable WAG ratio injection scheme, using a 7-12% hydrocarbon pore volume (HCPV) initial CO_2 slug followed by increasing water/gas ratio as the flood matures was found to be the most economically attractive WAG injection strategy for South Cowden. This WAG strategy provides an economic compromise of increased oil recovery efficiency over continuous CO_2 injection, while accelerating incremental oil response and reducing overall project life vs. a straight 2:1 WAG process.

TASK III TECHNOLOGY TRANSFER, REPORTING, AND PROJECT MANAGEMENT ACTIVITIES FOR BUDGET PHASE I

Subtask III.1 Prepare and Submit Technical Papers for Presentation and Publishing

A technical paper entitled "Integrated Geological and Engineering Characterization of an Upper Permian Carbonate Reservoir, South Cowden Unit, Ector County, Texas -- A Work in Progress" was presented at the American Association of Petroleum Geologists Midcontinent Section Meeting, in Tulsa, Oklahoma, October 9-10, 1995. The paper was presented by Craig Caldwell, and described the results of the integrated reservoir characterization work, including regional mapping and 3-D seismic interpretation, the development of a stratigraphic framework, log analysis, and core analysis.

Ahmad Moradi made a presentation titled "Laboratory and Field Evaluation of CO_2 Foam" at the Petroleum Recovery Institute Forum on EOR Foam, Calgary, Alberta, Canada, November 15, 1995.

A poster session entitled "Reservoir Characterization of an Upper Permian Platform Carbonate in Preparation for a Horizontal-Well CO_2 Flood, South Cowden Unit, West Texas" was presented by C.D. Caldwell at the Oklahoma Geological Society / U.S. Dept. Of Energy Symposium, "Platform Carbonates in the Southern Midcontinent", Oklahoma City, OK, March 26-27, 1996. A number of core samples were included in the exhibit. This poster session summarized, again, the results of the integrated reservoir characterization study.

The Society of Petroleum Engineers Permian Basin Oil & Gas Recovery Conference held March 27-29, 1996 in Midland, TX, included a poster session entitled "Construction of a 3-D Geologic Reservoir Description from Core and Well Log Data, South Cowden Field CO_2 Project". A technical paper, SPE 35226, "Use of Production and Well Test Data with Predictive History Matching to Improve Reservoir Characterization for CO_2 Flooding at the South Cowden Unit" by K. J. Harpole, M.G. Gerard, S.C. Snow, and C.D. Caldwell was also presented. This paper presented the approach used in the South Cowden project to improve the delineation of the porosity and permeability distribution in the reservoir by integrating production performance data with 3-D geological modeling and predictive history matching techniques.

Matthew G. Gerard made a presentation titled "Application of Horizontal CO_2 Injection Wells at South Cowden Unit" to the Midland chapter of the Society of Petroleum Engineers, April 1, 1996. Gerard later made the same presentation at the Permian Basin Horizontal drilling Symposium on May 8, 1996.

Paper SPE 35429, "Determination of Relative Permeability and Trapped Gas Saturation for Predictions of WAG Performance in the South Cowden CO_2 Flood" by D.C. Wegener and K. J. Harpole was presented at the Improved Oil Recovery Symposium in Tulsa, OK on April 22-24, 1996. This paper describes the laboratory experimental apparatus and procedures developed and used to measure key parameters (CO_2 relative permeability, residual oil saturation following miscible CO_2 displacements, trapped gas saturation, and hysteresis effects) governing CO_2 injectivity and displacement efficiency in the South Cowden miscible CO_2 WAG injection project.

Matthew G. Gerard made a presentation of the Phase I work at the DOE Class II Workshop held at the CEED in Midland, May 15-16, 1996.

Ahmad Moradi, E.L. Johnston, D.R. Zornes and K.J. Harpole submitted an abstract entitled "Laboratory Evaluation of Surfactants for CO_2-Foam Applications at the South Cowden Unit", for the International Symposium on Oilfield Chemistry, February 18-21, 1997 in Houston, Texas. A copy of the abstract is attached. (Attachment IV)

Matthew G. Gerard and Ken J. Harpole submitted an abstract entitled "Incorporating Production and Petrophysical Data to Improve Predictivity History Matching for a CO_2 Flooding Project at South Cowden Unit, West Texas" for the Fourth International Reservoir Characterization Technical Conference, March 2-4, 1997 in Houston, Texas. A copy of the abstract is attached (Attachment V).

PHASE II

TASK V FIELD DEMONSTRATION

Subtask V.1.1 Drill, Core, Complete, Test, and Evaluate Well RC-3 (SCU 6-24)

The third reservoir characterization well (RC-3) for the project has been given the well number SCU 6-24. This well was drilled in November and December, 1995. The location of the well is shown on the attached map (Figure 26). Core was taken from the depth interval 4586-4766', recovering 179.5 feet of core. Routine whole core analysis measurements of porosity, permeability, and fluid saturations have been completed. The core was slabbed and sent to the Phillips core facility in Bartlesville. There a petrographic study is being done, including macroscopic core description and thin sections.

Well logs indicated greatly reduced porosity in the Upper E and F zones, compared to offset wells. Initial examination of the core indicates that anhydrite cementation may be responsible for the porosity reduction, and that the permeability is also low. The well was perforated in the lower E, upper D, and C zones. The well tested 200 barrels of water per day (BWPD) and 0 barrels of oil per day (BOPD) flowing, and has been temporarily abandoned. The well may be reactivated as a producer or CO_2 WAG injector after CO_2 injection has begun in the project.

Subtasks V.1.2 and V.1.3 Drill Horizontal Injection Wells

Drilling of South Cowden Unit Horizontal CO_2 Injection Wells (6C-25H and 7C-11H)

The drilling and completion operation for the horizontal CO_2 injector 6C-25H (East well) began March 17, 1996 and was completed in 28 days. Due to several contractor and equipment failures, the 6C-25H was completed four days after the estimated completion date. The drilling operation for the horizontal CO_2 injector 7C-11H (North west well) began April 14, 1996 and was completed in 20 days. The experience gained in the first well was a major factor in completing the 7C-11H four days ahead of the estimated completion date (Figure 27 and Figure 28). This can be also be attributed to the combination of good communications, contractor preparation / experience, and the experienced drilling supervisor staff.

The South Cowden Unit Horizontal CO_2 injection well trajectories were designed to optimize reservoir performance, maximize sweep efficiency, and optimize injectivity performance. The design and actual results of 6C-25H and 7C-11H horizontal injection wells are included as Table 3.

The designed parameters and the actual resulting well values matched with exceptional accuracy. Visual representations of the drilling curves for 6C-25H and 7C-11H can be found in Figures 29 and 30, respectively.

Drilling operations had to be modified in several ways to accommodate the drilling of the horizontal wells. The drilling contractor had to provide an adequate mud system (such as a flowline cleaner, agitators, rolling lines, and a 200 bbl pre-mix pit) to effectively condition the polymer mud system. In addition to the rig specifications, a centrifuge had to be acquired to further condition and maintain the mud, thus optimizing the polymer mud properties. The polymer-based mud was utilized because of its hole sweeping efficiencies, thin filter cake production, solids retention time, friction coefficient in relation to reducing hydraulic pipe drag, viscosities, filtrate loss, and gel strength characterizations. Optimizing these characteristics enhanced penetration rates and hole conditioning, and limited stuck pipe potential. In addition, triplex pumps with sufficient horsepower were required to reduce interference with measurement while drilling (MWD) pulse readings and maximize mud motor performance.

The directional drilling of the curve section and lateral section required several bottom hole assembly (BHA) adjustments. The bit was a tungsten carbide insert toothed tri-coned roller cutter bit with tungsten carbide inserts around the circumference of the bit to provide bit stabilization while directionally sliding the drillstring and maintaining the bit and hole in gauge. Directional measurements were acquired by utilizing a positive pulse MWD system. Details on the BHA are included in Table 4.

The wells were designed mechanically to optimize well injection performance and useful well longevity. Both wells were designed to accommodate 9-5/8", 36 ppf, J-55 surface casing, 7", 20 ppf, J-55 production casing through the curve, and a 6-1/8" openhole injection interval. The production casing was designed with 7" tubulars to accommodate 3-½" production tubing. The 20 ppf casing weight was utilized more for additional corrosional wear allowables than for withstanding the predicted injecting bottom hole pressures. The cased curve trajectory was designed to accommodate 125' of production casing within the San Andres producing interval. This was to maximize packer setting depths in relation to corrosion exposure of casing below the injection packer during workovers. The 3-½" injection tubing was utilized for maximizing injection rate and volumes. The entire downhole injection system had to resist the corrosion effects of CO_2 injection alternating with water injection. This was done by lining the tubing with fiberglass inserts and coating the injection packer internally with plastic and externally with nickel plating. The injection tree, for corrosion purposes, had to be constructed of solid stainless steel. The completion string can be viewed on Figures 31 and 32.

Subtask V.1.4 Drill Vertical Wag Injection Wells

Two vertical CO_2 WAG injection wells were planned for Tract 2 in the northwest portion of South Cowden unit (Figure 26). Tract 2 is in the structurally highest part of the unit, where Zones C and A, underlying the main pay zones E and D, are oil bearing. The vertical injection wells in this area of the field will permit direct flooding of all four zones with CO_2, and improve the oil recovery of the project.

The proposed injection wells SCU 2-26W and 2-27W were drilled in December, 1995. The SCU 2-27 has been temporarily completed as a producing well, and tested 10 BOPD, 100 BWPD from zones C through F. This well will be converted to CO_2 injection when the pipeline and injection facilities have been completed, in July 1996. SCU Well 2-26W has not yet been completed, pending completion of the injection facilities and pipeline.

Subtask V.1.5 Drill Multiple Producing Wells

Two additional production wells, the SCU 6-22 and SCU 7-12, were drilled and completed in November and December, 1995. The well locations are shown in Figure 26. These wells are needed to drain areas of the field offsetting the horizontal injection wells, replacing old wells which have been plugged and abandoned. The SCU 6-22 tested 100% water from the D and E zones. It was plugged back to the G zone and tested 9 BOPD and 148 BWPD. The SCU 7-12 was completed in zones D through F and tested 5 BOPD and 270 BWPD.

Subtask V.1.6 Convert Five Wells for Water Injection

Operations commenced to convert SCU Wells Nos. 2-21, 5-02 and 8-18 to water injection.

Subtask V.2 Construct, Modify, and Upgrade Facilities for Injection and Production

Purchase Land, Install Perimeter Fence and Hydrogen Sulfide (H_2S) Monitors

Five of six private lots in Section 17 of the South Cowden Unit have been purchased, with negotiations continuing on the sixth lot, for the construction of production facilities. The main 250-acre tract of land where CO_2 flood facilities are located are currently being leased. Purchase of the land is anticipated to reduce costs associated with right of way and damages for installation of injection lines and production flowlines.

Nineteen of twenty-one H_2S monitors have been installed and are operational. All H_2S monitors along the perimeter fence have been installed and are operating. If H_2S is detected by any of the monitors, an alarm is sent via radio to the Phillips Petroleum Odessa office South Cowden Unit (SCU) Supervisory Control and Data Acquisition (SCADA) computer, which in-turn sends a message to an operator on-call who will have an alpha-numeric pager. If the operator on-call cannot be reached, a list of people will be called until someone acknowledges the alarm.

The perimeter fence is approximately 95% complete. This fence is to prevent public entrance into the project area, provide protection from exposure to H_2S and protect against vandalism. The fence will be completed upon purchase of the sixth private lot.

Construct Compression Facilities

Production Operators, Inc. (POI) completed construction of their re-injection facility on June 21, 1996. The facility is currently equipped with a 330 horsepower (HP) Caterpillar Natural gas engine / Ariel compressor package rated up to 1.0 MMscfD, and includes a Glycol gas dehydration skid for removing water from the produced gas prior to re-injection.

Installation of Injection Runs at Headers and Wellheads

Installation of injection runs to all four of the CO_2 WAG injection wells is completed. Installation continues at the water injection wells.

Installation of Fiberglass WAG System

Installation is completed on the new fiberglass WAG system to the four CO_2 WAG injection wells. Installation consisted of approximately 5600' of 2" and 2400' of 3" 2500-psig fiberglass pipe.

Installation of H_2O and CO_2 Manifold

Construction and installation of the H_2O and CO_2 (WAG) manifold is completed. The injection manifold consists of eight (8) 2" stainless steel injection runs, and will accommodate the four SCU WAG wells, three future leaseline wells, and one spare. The injection chokes on each injection run are fully-automated and control the volume of water or CO_2 going to each WAG well.

Upgrade Production Facilities

Construction of the new Tract 6 Satellite facility continues. A new production header is complete, and a new production separator and test separator have been built and installed, tieing the facility into the Tract 6 main battery. As the CO_2 content of the produced gas increases in the SCU producing wells, individual wells will be rerouted and tied into the new Tract 6 satellite facility.

Injection System Replacement

Replacement of the old water injection system is essentially complete. Replacement consisted of the installation of 2000 psig fiberglass pipe in the following lengths and sizes: 5100' of 4", 3200' of 3", 1600' of 2-1/2" and 11000' of 2".

Cathodic Protection

Logging runs using a Cathodic Protection Evaluation Tool (CPET) were made in the SCU #6-20 and #7-05 wells. A cathodic protection deep anode bed was installed near the SCU #6-20 well and both wells logged first without cathodic protection and then logged with the cathodic protection system turned on. Log evaluation is to continue before a decision is made whether or not to install fieldwide cathodic protection on all the wells.

Installation of SCADA Equipment

The SCADA system has been installed and is operating. WAG injection manifold pressures and flow rates are being sent to the SCADA computer located in the Phillips Petroleum Odessa office, along with various alarms. Installation of producing well pump-off controllers continues. Well performance and status will also be sent via radio to the SCADA computer.

Subtask V.3 Purchase CO_2 and Operation of Recycle Compression

CO_2 will be supplied to the South Cowden Unit Project via a 13-mile Odessa lateral connecting South Cowden field with the Central Basin CO_2 Supply Line. The lateral is owned by Morgan & Associates, but is operated by Enron Liquids Pipeline Company, who also operates the Central Basin CO_2 Supply Line. The six-inch diameter Odessa Lateral is designed to deliver up to 20 MMCFD to the South Cowden field. The South Cowden Unit project is expected to require up to 15 MMCFD of CO_2 during the initial years.

Phillips has entered into an equipment purchase and contract gas compression services agreement contract with Production Operators, Inc. (POI) which includes equipment, installation, operation and maintenance of the recycle compression facility. Phillips provided a location and access road. Phillips, as operator of the South Cowden Unit, and Fina, as operator of the adjacent Emmons Unit, will own all materials and equipment with the exception of the driver/compressor unit, the glycol reboiler unit and the contactor vessel unit, which will be owned by POI.

Certain tie-ins to the intake and discharge headers, fuel gas, waste water, condensate, and data collection systems were provided by Phillips, who also provided fuel/purge gas and electricity and will be responsible for the sale or disposal of waste water and/or condensate. Phillips has also constructed both produced gas and compressed gas lines for their Unit, and supplied the necessary gas meters. Costs and expenses for the operation and maintenance of the meters will be charged to a joint account for the two Phillips- and Fina-operated Units.

The unusual and particularly beneficial aspect of the Compression Facility Agreement lies in the sharing of installation and operating costs by Phillips and Fina. Under normal operations, each company would have separately negotiated their own compression arrangements; however, the combined facility allowed for the reduction of installation and operating costs for both Units.

Subtask V.5.1 Complete Petrologic Description of Core from Well RC-3

Burrow-mottled dolopackstones composing the SCU reservoir interval are composed of gray, relatively low-porosity and low-permeability dolowackestones/dolopackstones and tan, oil-stained, more porous and permeable dolopackstones/dolograinstones. Tan dolomite areas are burrows. Interburrow areas are gray lower porosity dolomite. The relative amounts of gray and tan dolomites composing the SCU reservoir interval markedly affect the reservoir porosity and permeability. A clear mylar sheet with a one-inch-square grid pattern was used to determine the relative amounts of gray and tan dolomites composing the reservoir interval in the SCU 6-24 core. These amounts, determined for each one-foot interval of the Grayburg reservoir, will be compared with gray/tan percentages similarly determined for the SCU 8-19, 7-10, 6-23, and 8-11 cores.

Reservoir porosity is also a function of anhydrite content. Thin section study of burrow mottled dolopackstones from the SCU 8-19, 7-10, 6-23, and 8-11 and the Moss Unit 16-14 shows that as anhydrite content increases reservoir porosity decreases. Thin section study of reservoir dolomites from the SCU 6-24 confirms these findings. Average anhydrite content of tan dolomites, determined from thin sections; and average porosities, determined from core analysis, are given in the following:

WELL	AVERAGE POROSITY	AVERAGE ANHYDRITE
SCU 8-19	24%	1%
SCU 6-23	21%	1%
SCU 7-10	21%	5%
SCU 8-11	14.5%	11.5%
Moss 16-14	6%	15.5%

Anhydrite content in the lower part of the reservoir interval in the SCU 6-24 (Zone E below 4675', log depth) averages less than 1% anhydrite. Porosity estimated from thin section for this interval is approximately 12%. Zones E and F above 4675' average 19% anhydrite and 4.5% porosity as determined from thin section (porosities estimated from thin section are typically lower than those determined by core analysis).

Tan dolomite areas have varying permeabilities related to pore size. Tan dolomites with similar porosities may have markedly different permeabilities. The average porosity of tan dolomites from SCU 6-23 and 7-10 is 21%, but the average permeabilities are 90 md and 10 md, respectively. Tan dolomites from SCU 7-10 have markedly smaller pores and finer dolomite crystal size than tan dolomites from SCU 6-23. Tan dolomite samples from SCU 6-24 vary markedly in crystal size and consequent pore size, resembling samples from both SCU 7-10 and 6-23.

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3. H. Yaghoobi and J. P. Heller, "Effect of Capillary Contact on CO_2-Foam Mobility in Heterogeneous Core Samples," Paper SPE 35169, Presented at the 1996 Permian Basin Oil and Recovery Conference , Midland Texas, March 27-29, 1996.

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6. A. M. Michels, R. S. Djojosoeparto, H. Haas, R. B. Mattern, P. B. Van der Weg and W. M. Schulte, "Enhanced Water Flooding Design Using Diluted Surfactant Concentrations for North Sea Conditions," Paper SPE/DOE 35372, Presented at the SPE/DOE Tenth Symposium on Improved Oil Recovery, Tulsa, OK, April 21-24, 1996.

LIST OF FIGURES

FIGURES

TYPE LOG

Figure 1

Phillips #8-19 South Cowden Ut.

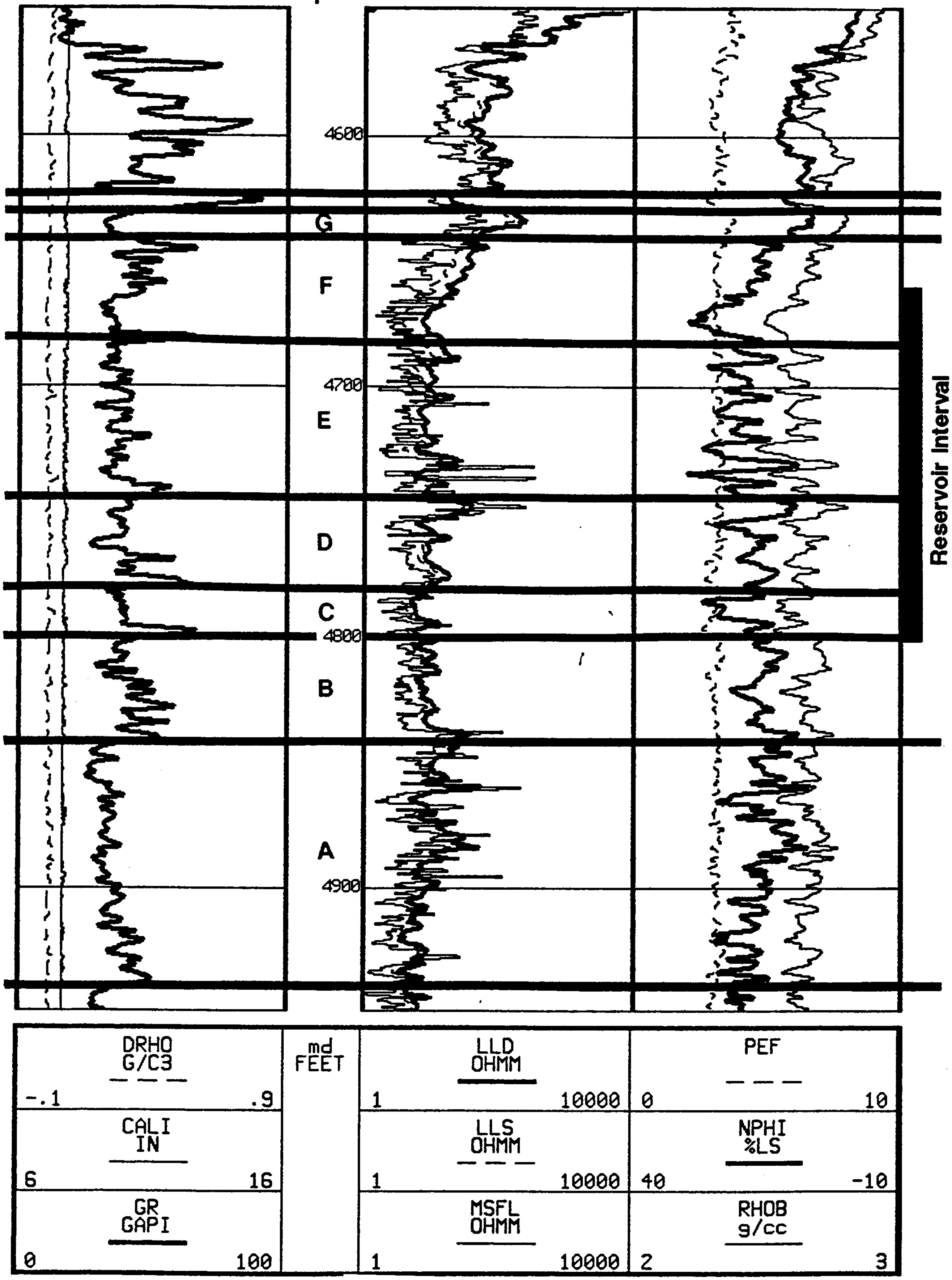
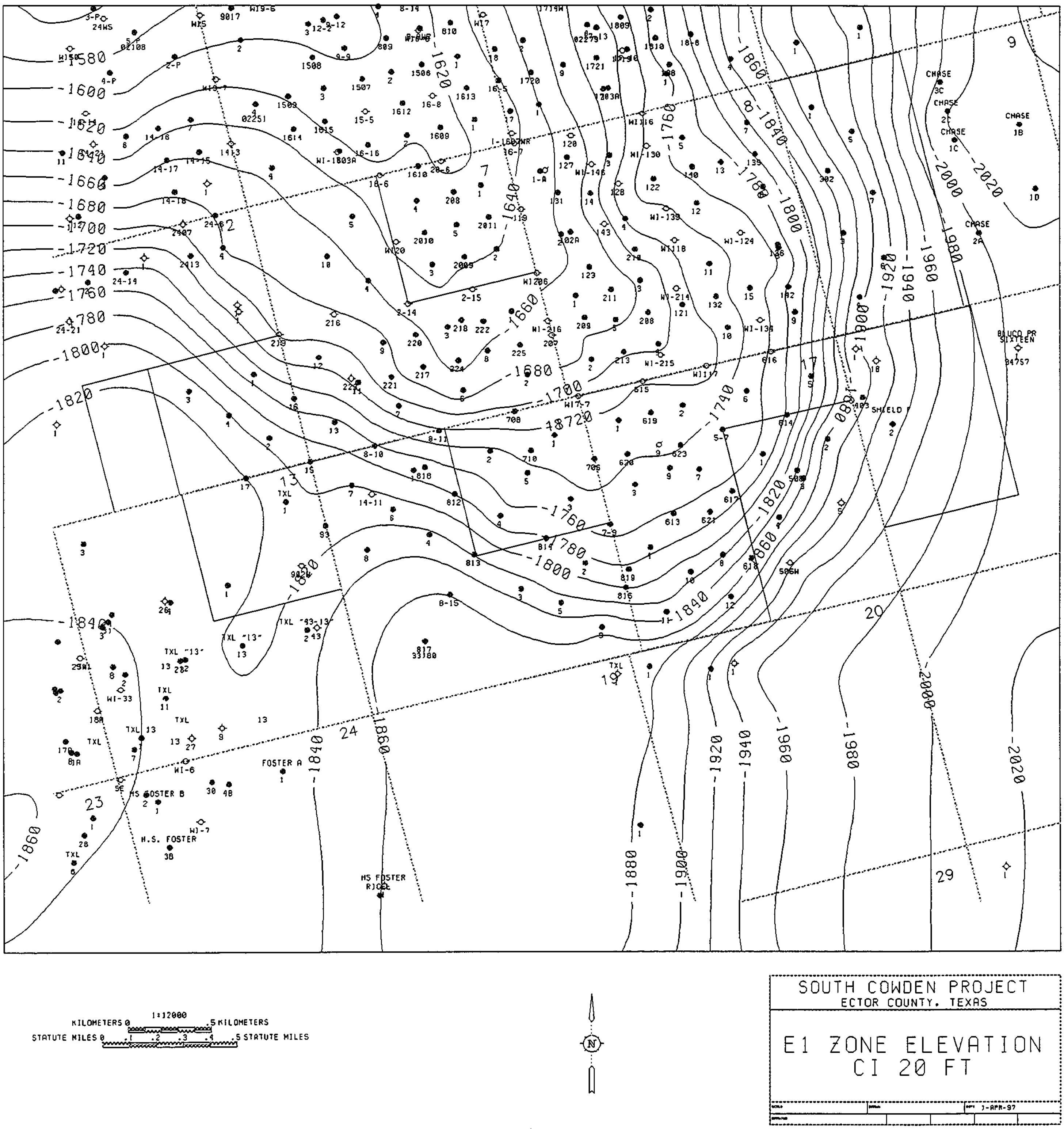


Figure 2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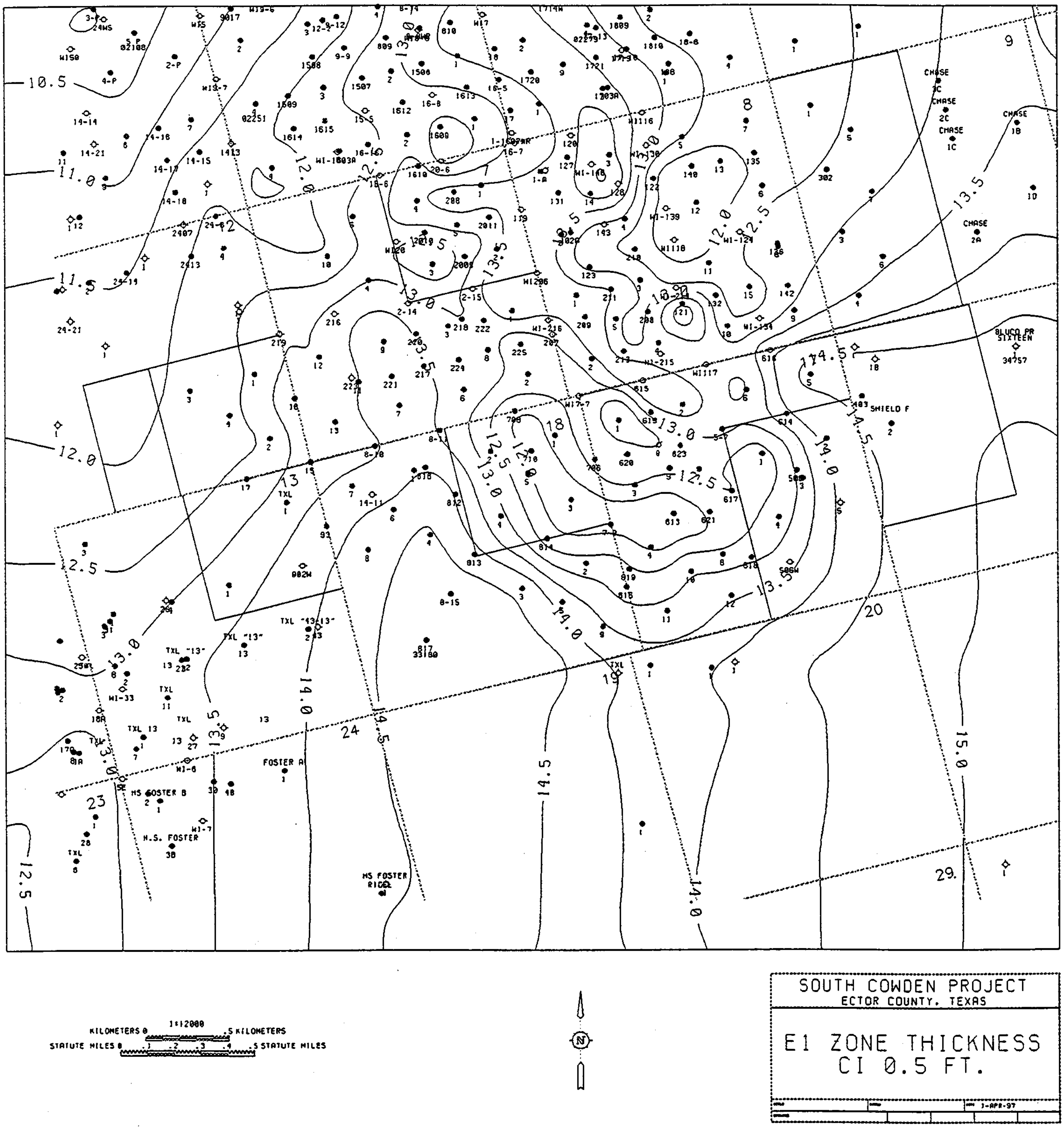
STATUTE MILES 0 .1 .2 .3 .4 .5 STATUTE MILES
N

Figure 3



SOUTH COWDEN PROJECT
ECTOR COUNTY, TEXAS
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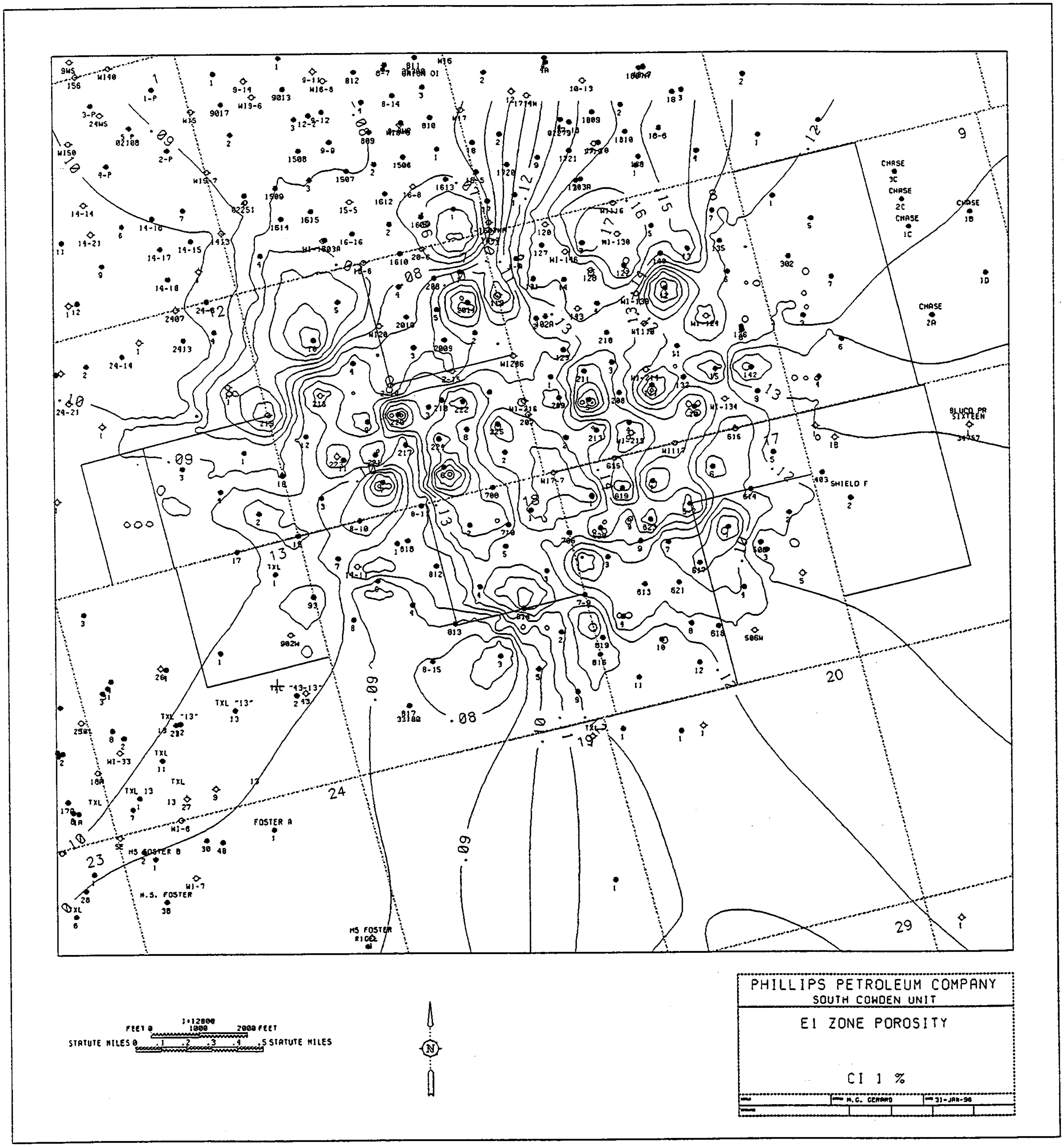
STATUTE MILES
.5 STATUTE MILES

Figure 4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2000 FEET
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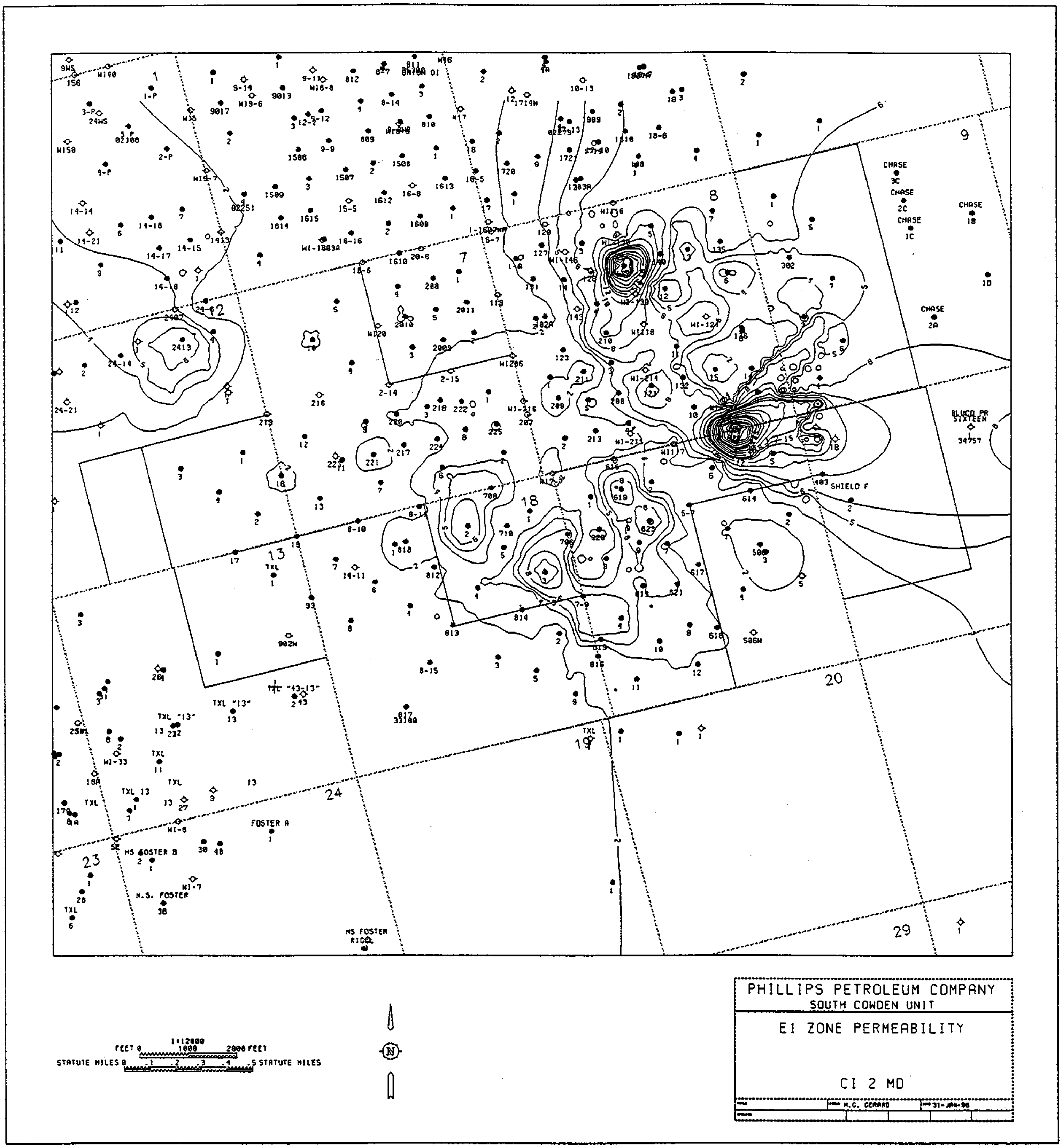
Figure 5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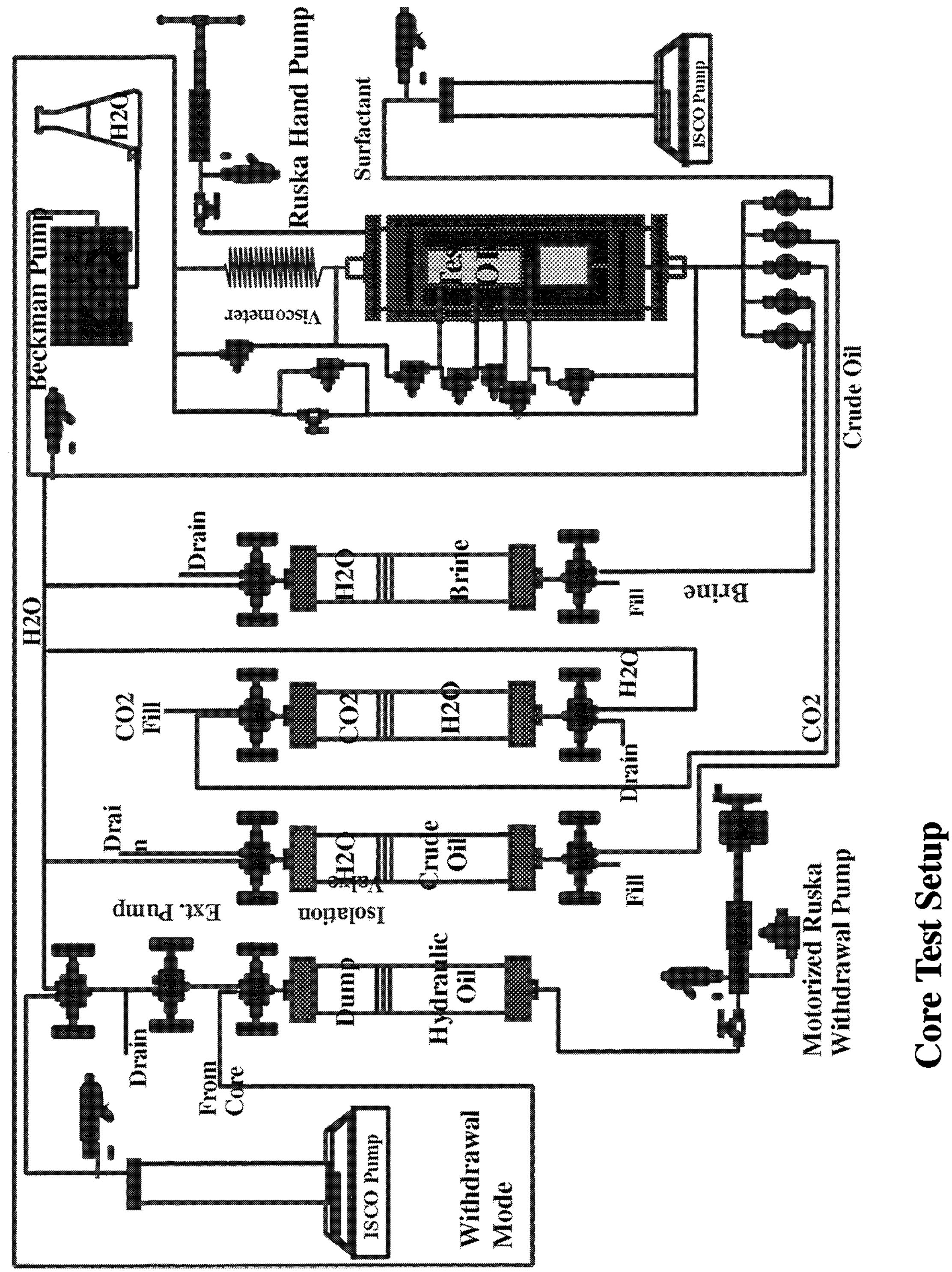
STATUTE MILES 0 .1 .2 .3 .4 .5 STATUTE MILES
SHIELD F
CHASE
BLUCA PR SIXTEEN
FOSTER A
MS FOSTER B
N.S. FOSTER
MS FOSTER RICE

Figure 6


Core Test Setup
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Beckman Pump
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Viscometer
Surfactant
ISCO Pump
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Drain
H2O
Brine
Fill
Brine
CO2
Fill
CO2
H2O
H2O
Drain
CO2
Drai n
H2O
Crude Oil
Fill
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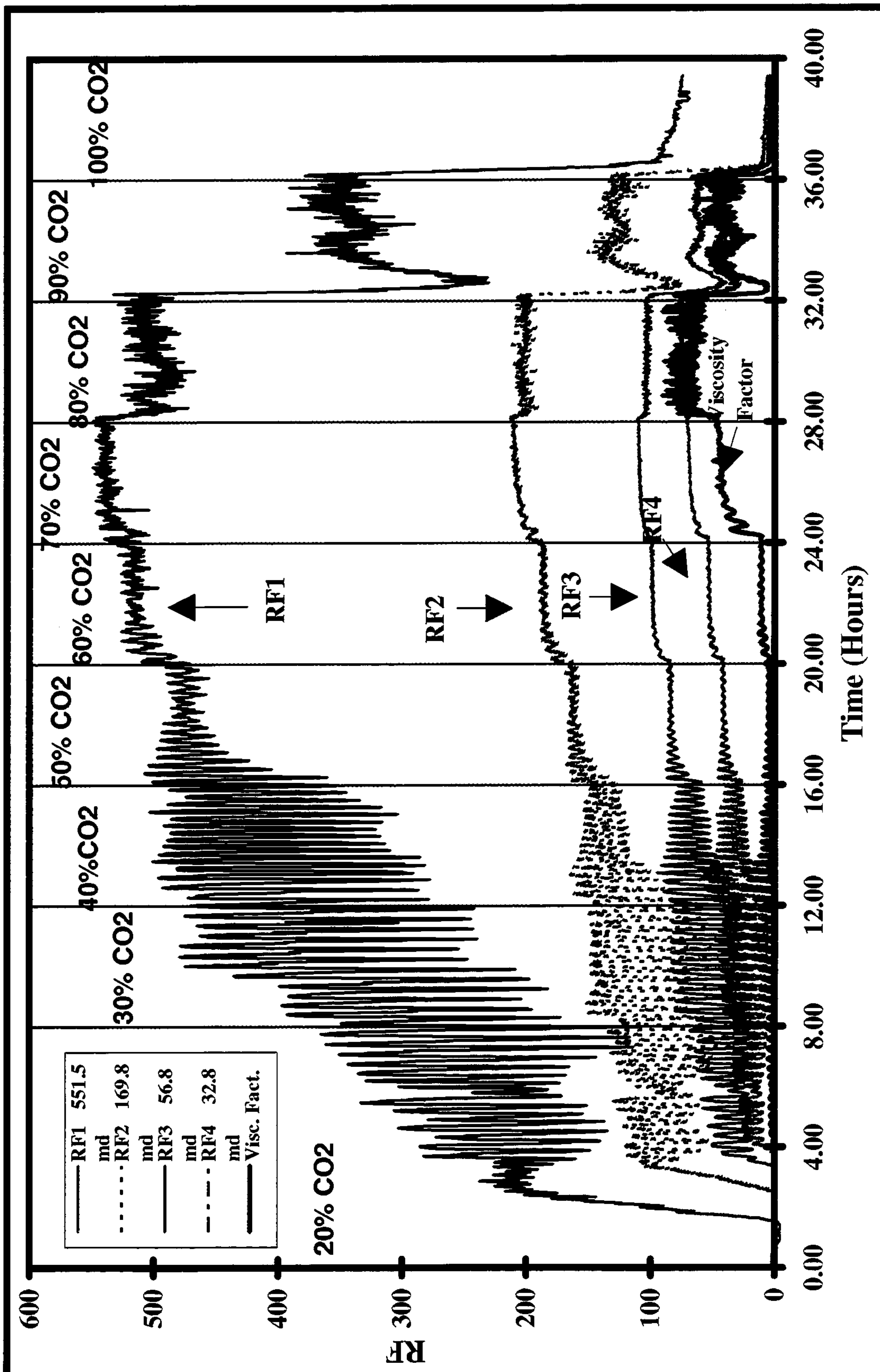
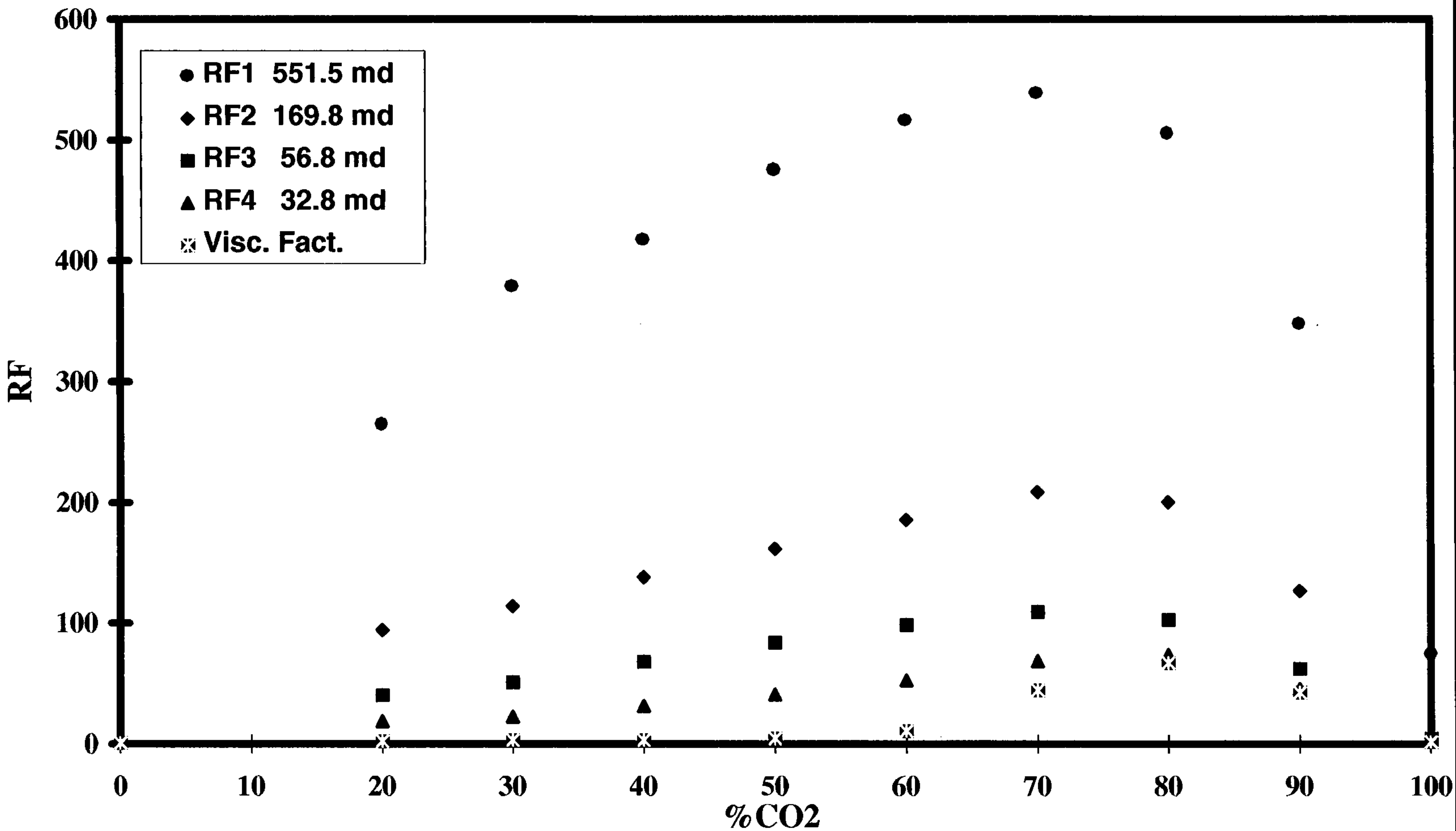
Drain
From Core
Motorized Ruska Withdrawal Pump
ISCO Pump
Withdrawal Mode

Figure 7



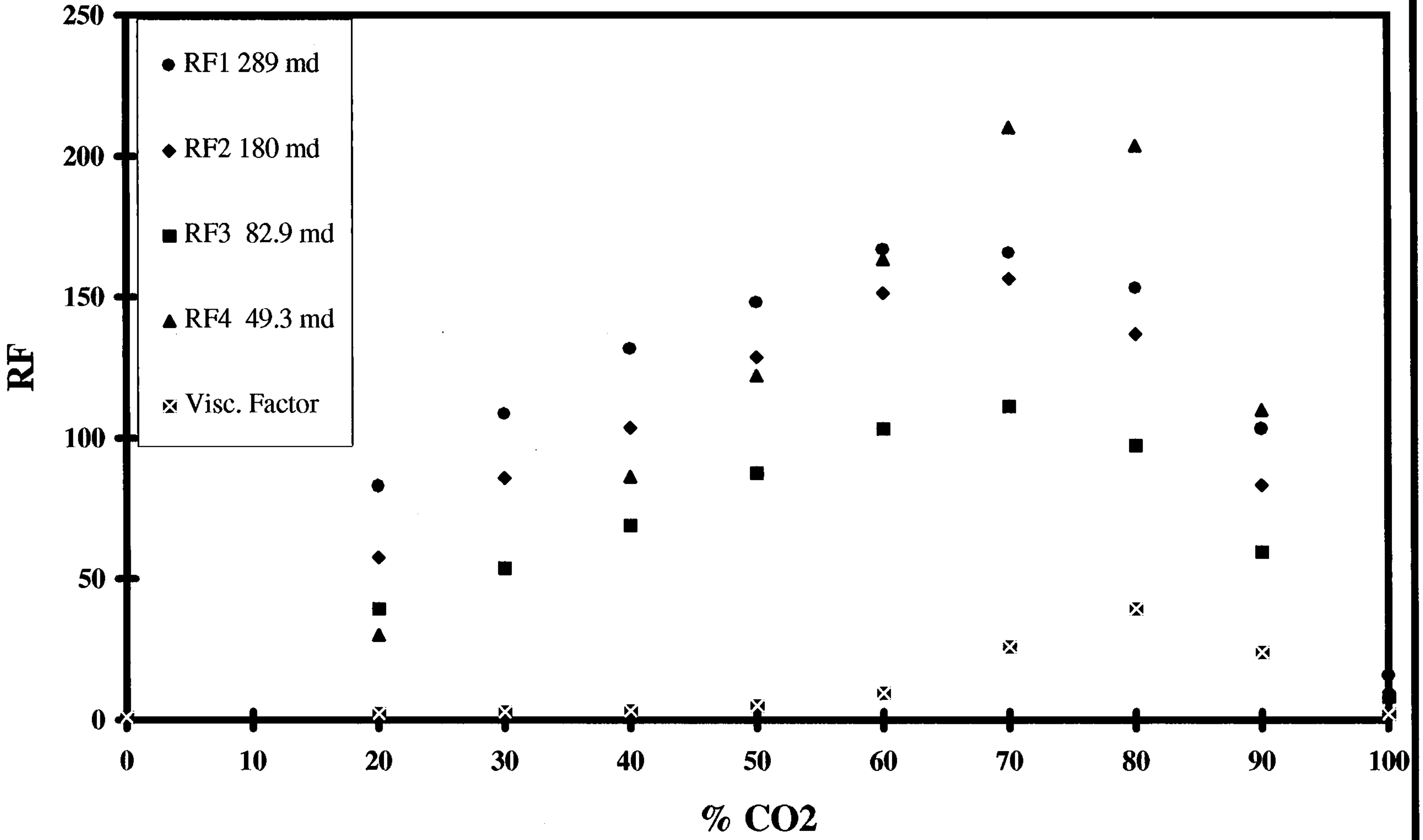
Performance of CO2-Foam Made with 2000 ppm Chaser CD-1050 in Synthetic South Cowden Brine (Test Core 12A, Pre-Foamer 10C).

Figure 8



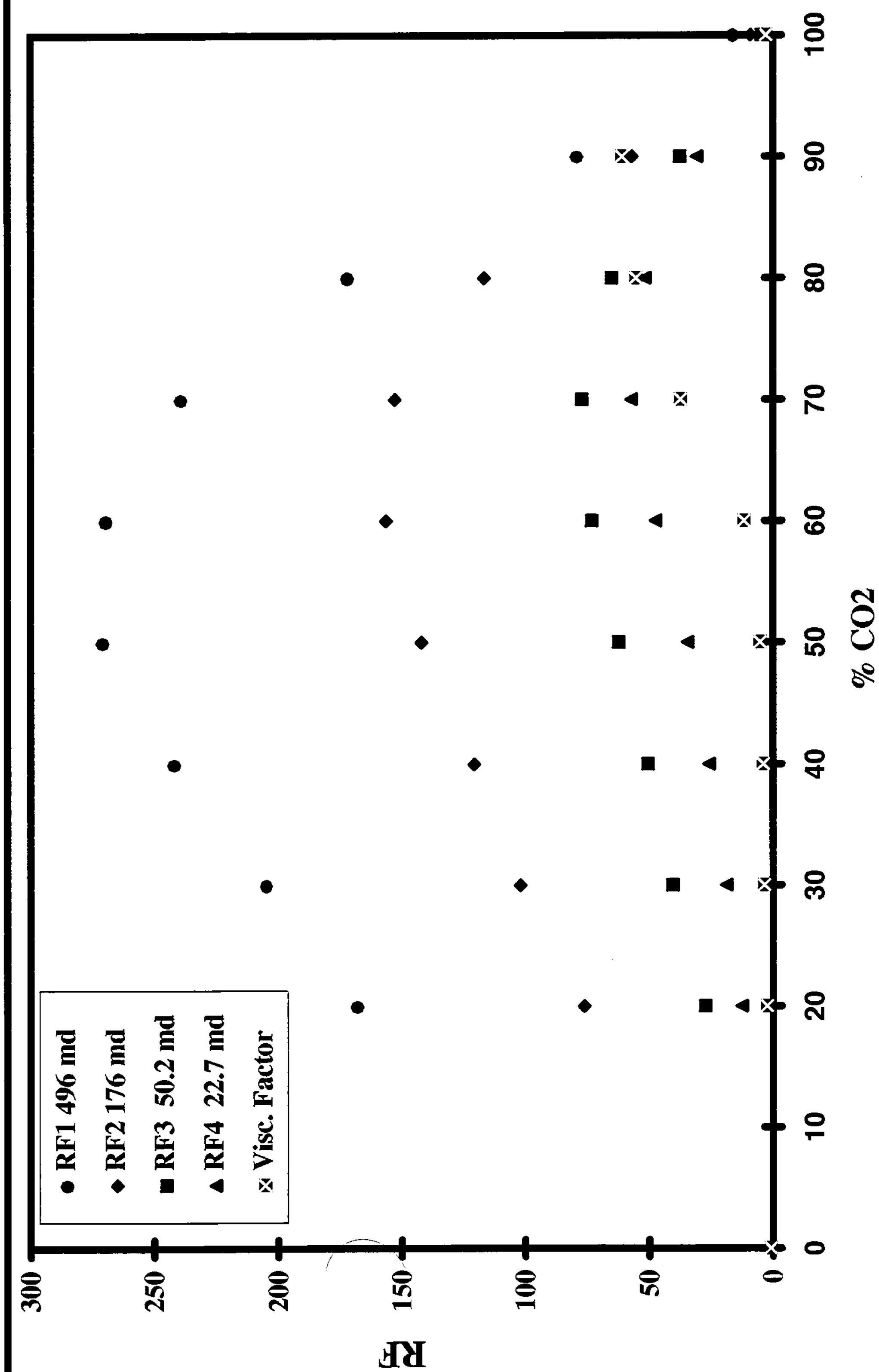
Performance of CO2-Foam Made with 2000 ppm Chaser CD-1050 in Synthetic South Cowden Brine as a Function of Foam Quality (Test Core 12A, Pre-Foamer 10C).

Figure 9



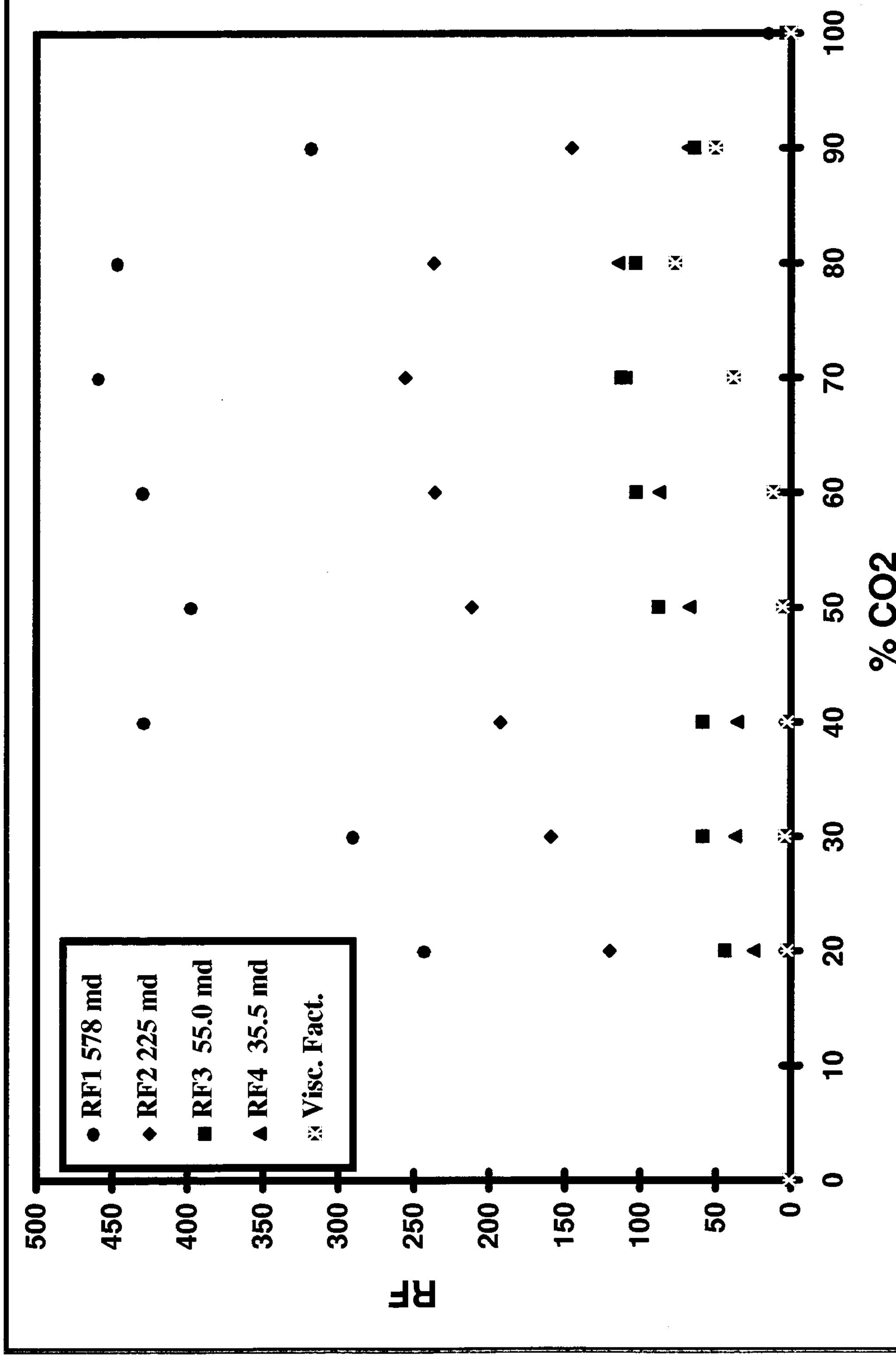
Performance of CO2-Foam Made with 2000 ppm Chaser CD-1045 in Synthetic South Cowden Brine as a Function of Foam Quality (Test Core 12A, Pre-Foamer 10C).

Figure 10



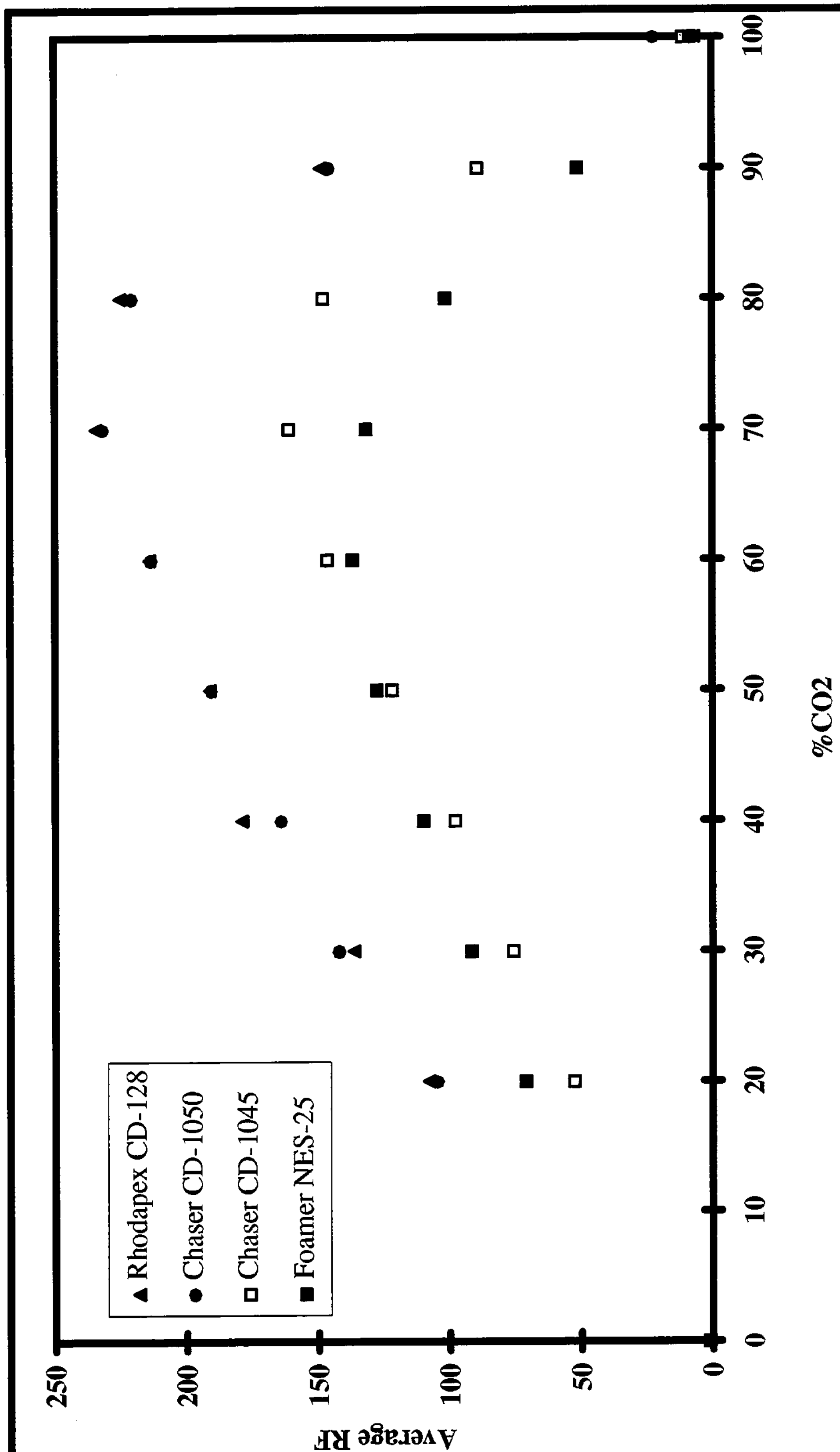
Performance of CO_2-Foam Made with 2000 ppm Foamer NES-25 in Synthetic South Cowden Brine as a Function of Foam Quality (Test Core 12A, Pre-Foamer 10C).

Figure 11



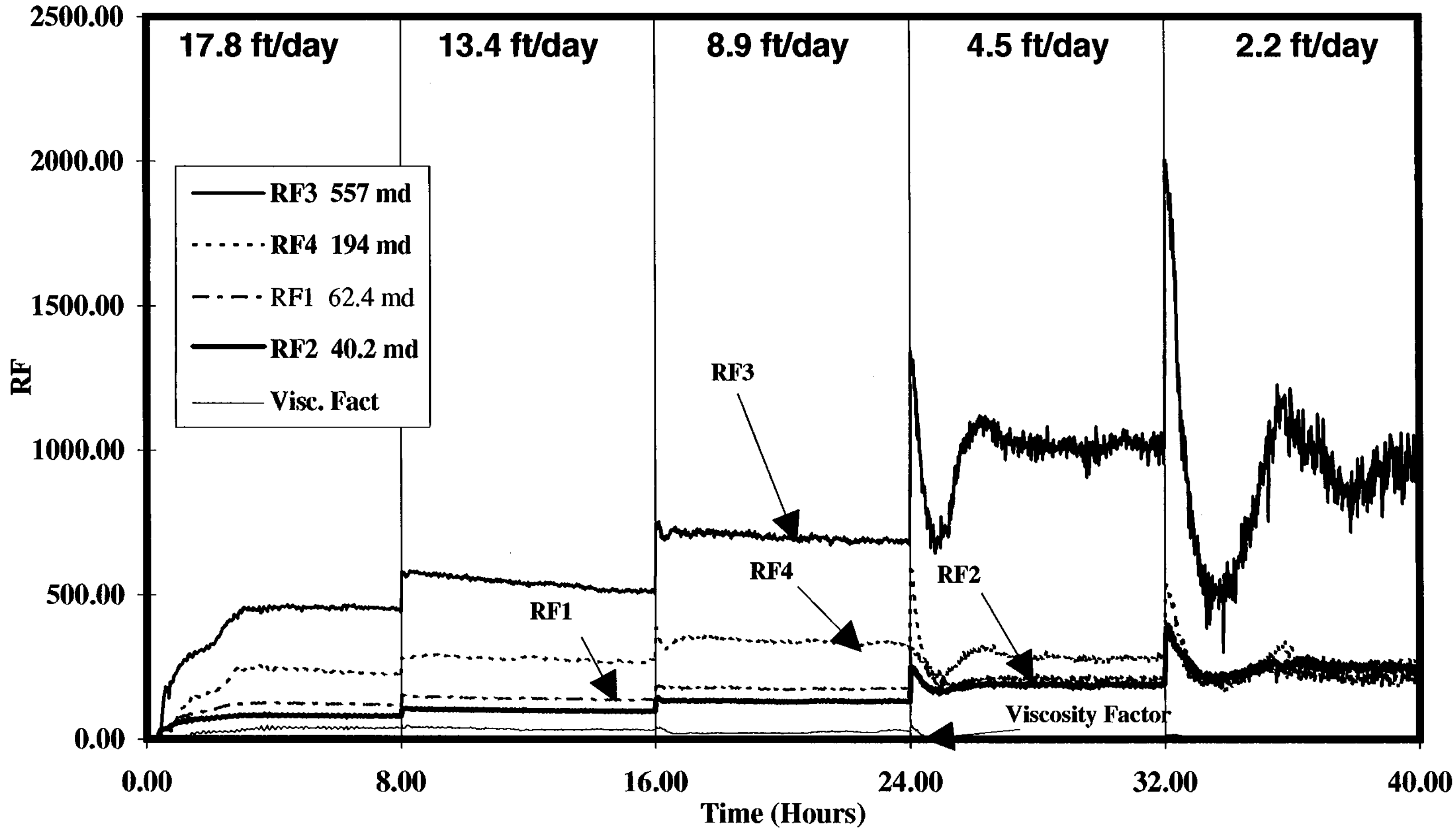
Performance of CO_2-Foam Made with 2000 ppm Rhodapex CD-128 in Synthetic South Cowden Brine as a Function of Foam Quality (Test Core 12A, Pre-Foamer 10C).

Figure 12



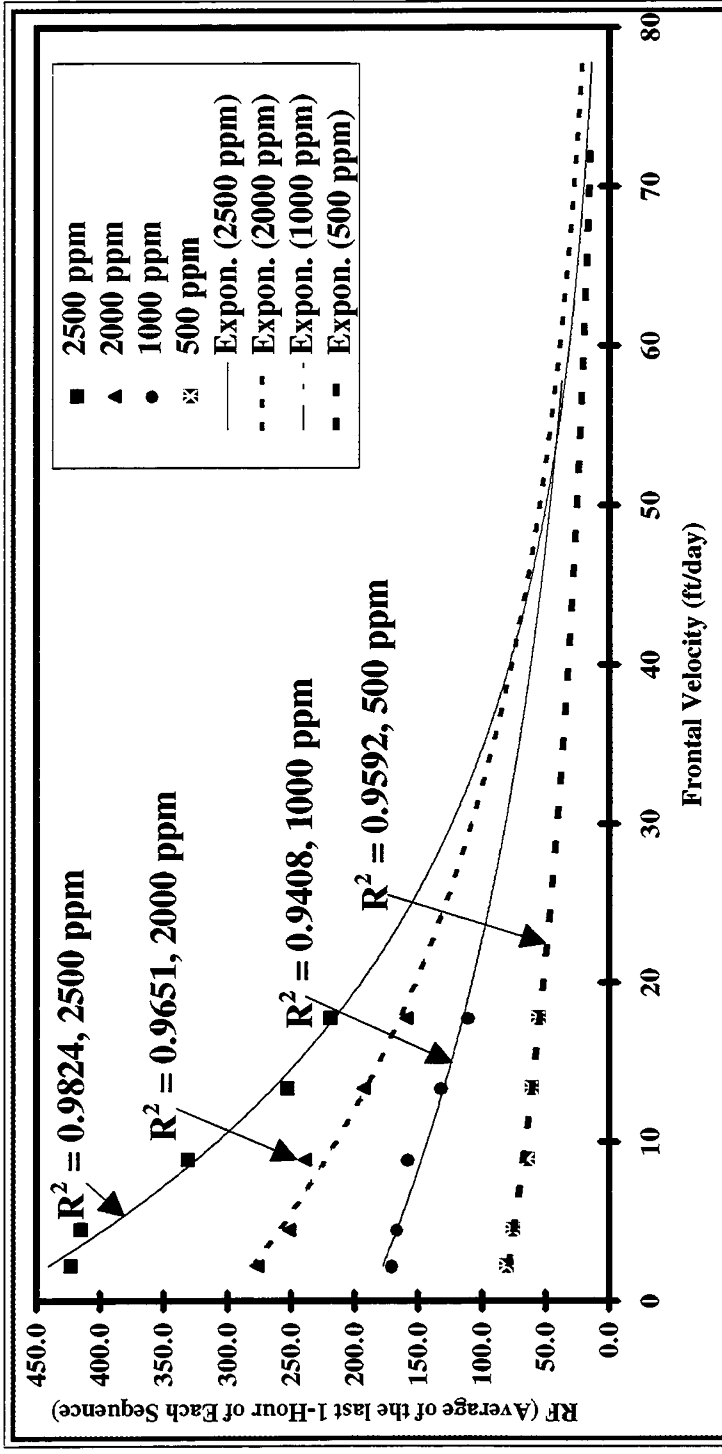
Comparison of CO2-Foams Made with 2000 ppm Each of Chaser CD-1045, Chaser CD-1050, Rhodapex CD-128 and Foamer NES-25 in Synthetic South Cowden Brine as a Function of Foam Quality (Test Core 12A, Pre-Foamer 10C).

Figure 13



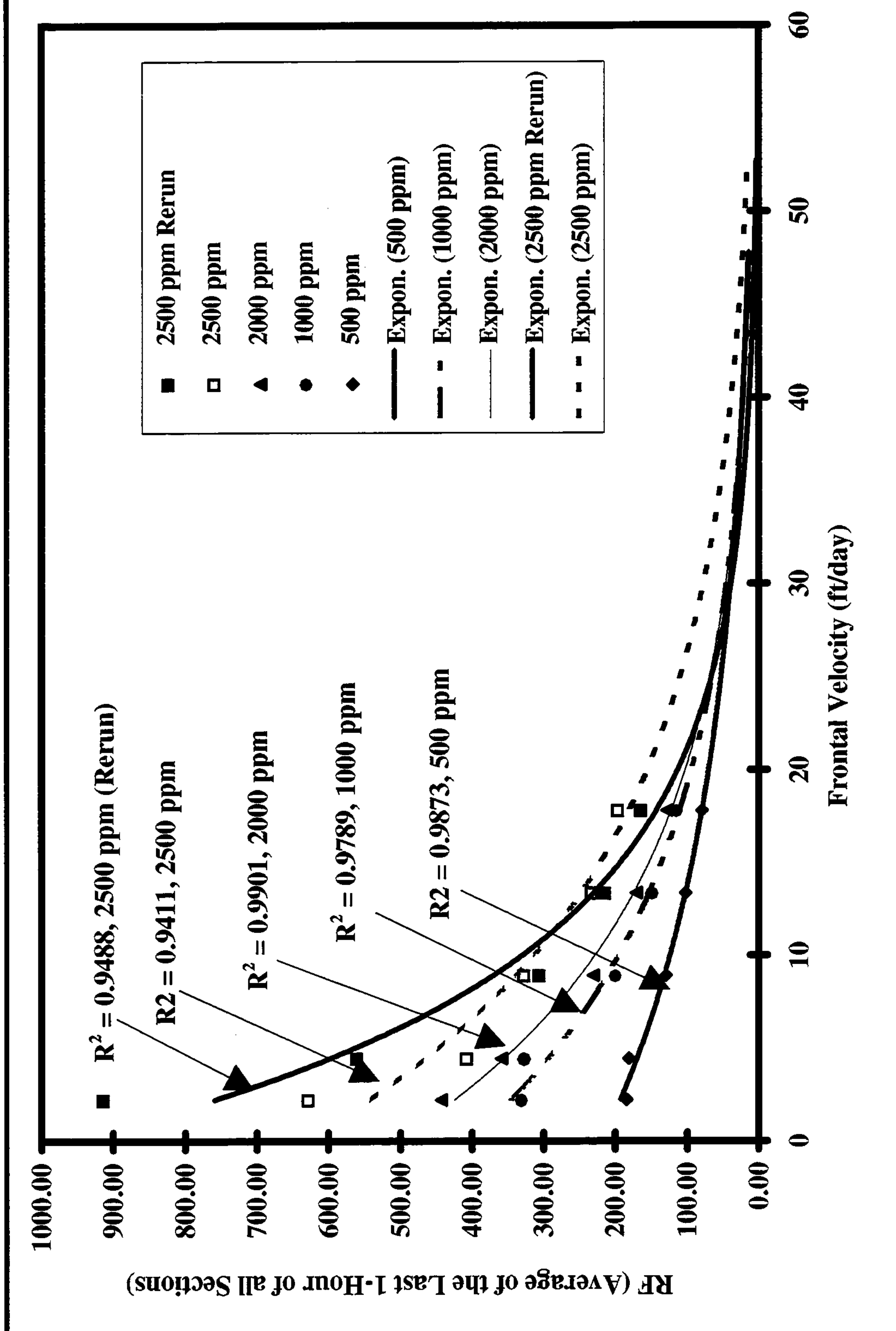
Effect of Frontal Velocity on RF for CO2-Foam (70% Quality) Made with 2500 ppm Rhodapex CD-128 in Synthetic South Cowden Unit Brine (Test Core 10B, Pre-Foamer 3C).

Figure 14



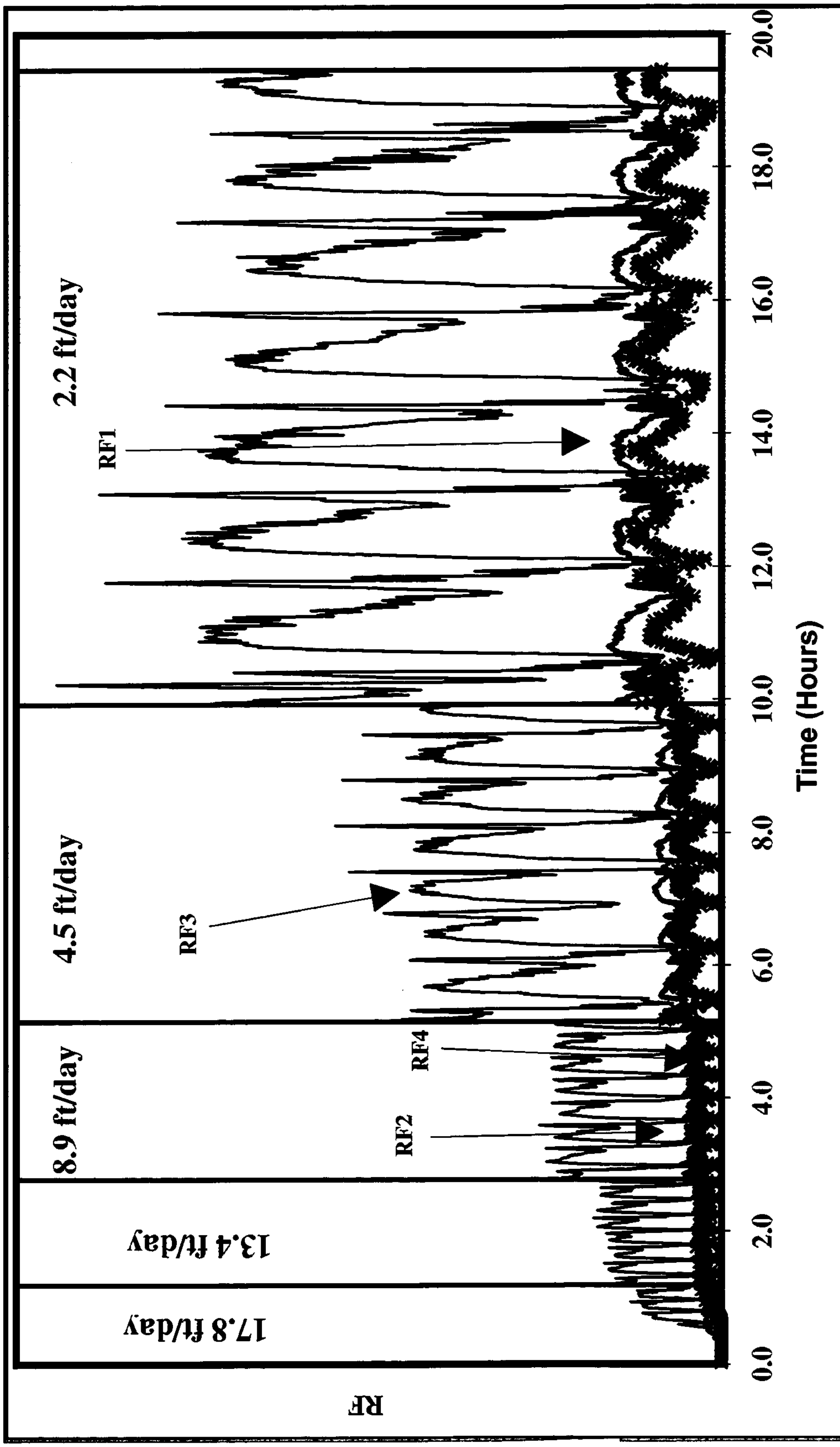
Effect of Frontal Velocity on Average RF for CO2-Foam (70% Quality) Made with Rhodapex CD-128 in Synthetic South Cowden Unit Brine at Various Concentrations (Test Core 10B, Pre-Foamer 3C).

Figure 15



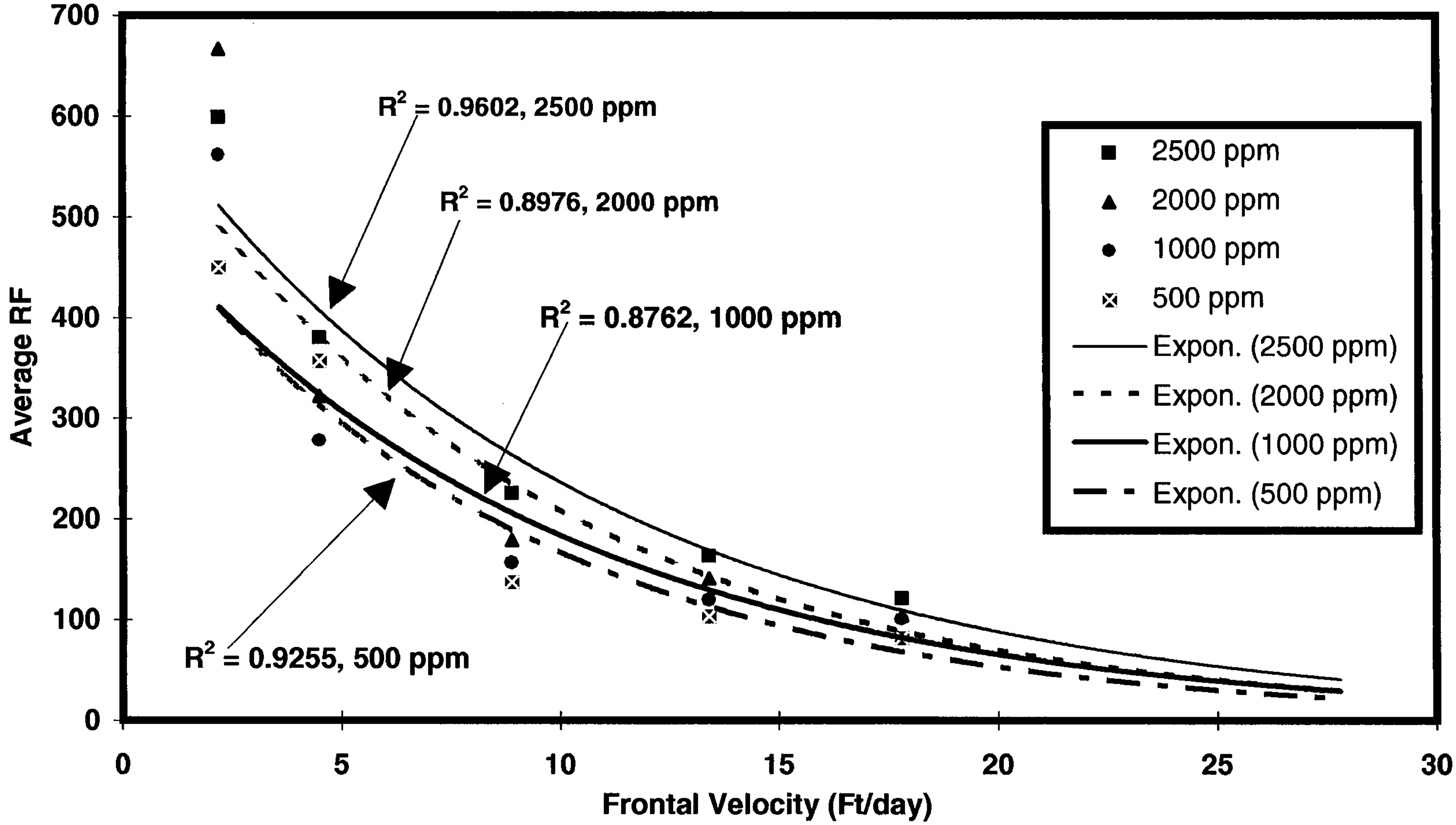
Effect of Frontal Velocity on Average RF for CO2-Foam (70% Quality) Made with Chaser CD-1045 in Synthetic South Cowden Unit Brine at Various Concentrations (Test Core 10B, Pre-Foamer 3C).

Figure 16

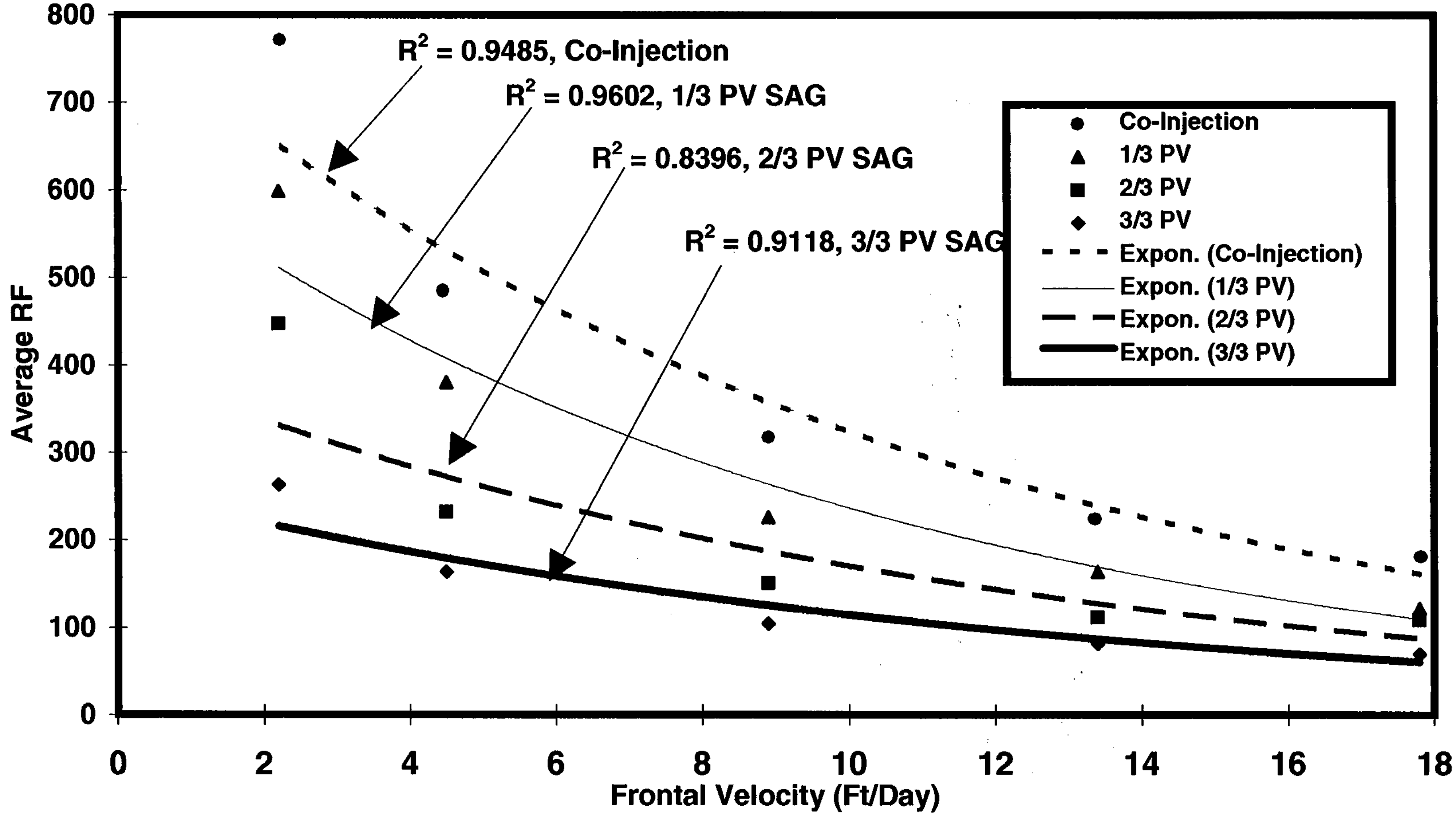


Effect of Frontal Velocity on Performance of the Foam Produced with 2500 ppm Chaser CD-1045 in a SAG Process (1/3 PV, 70% Foam Quality, Test Core 10B, Pre-Foamer 3C).

Figure 17

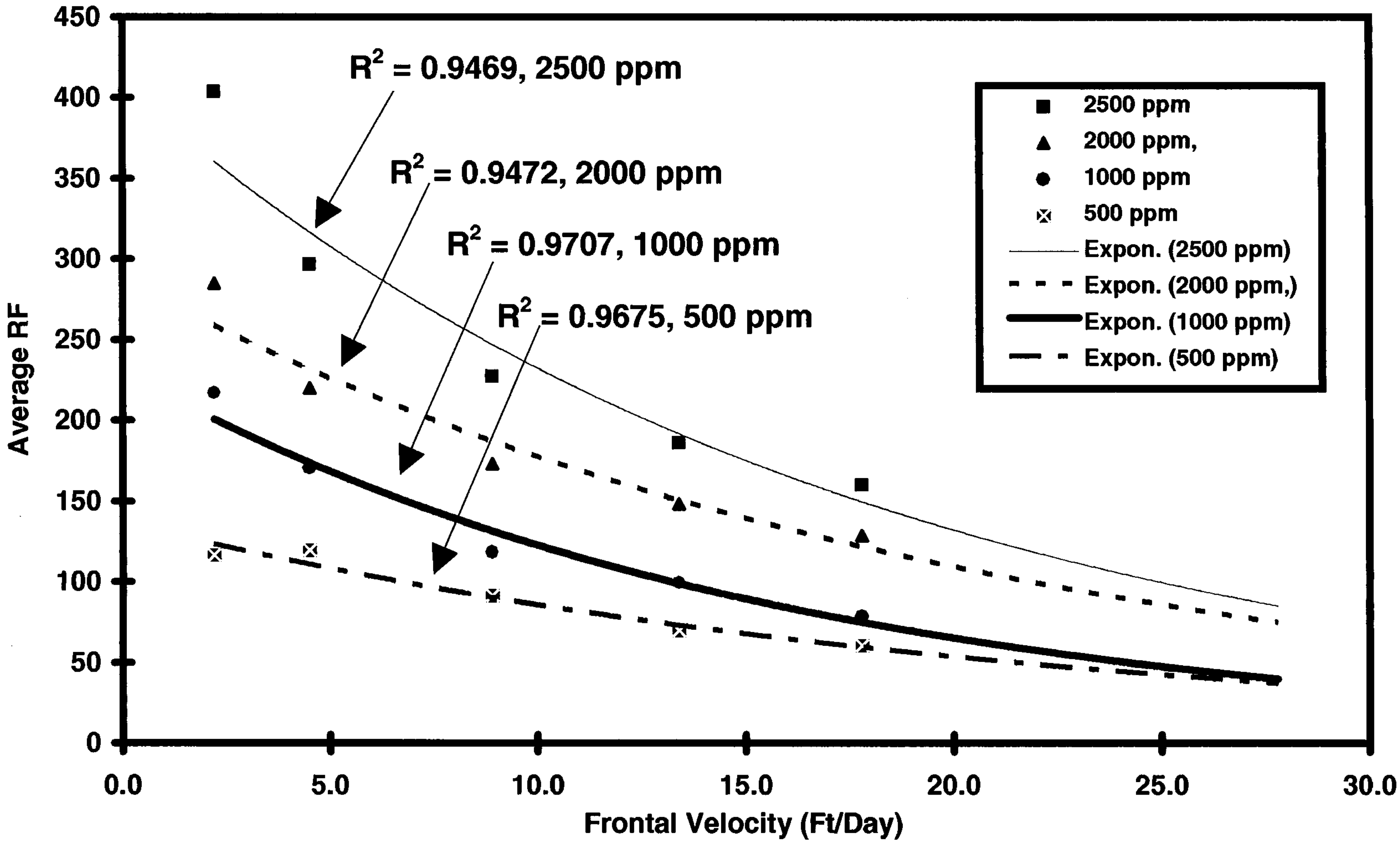


Effect of Frontal Velocity on Average Resistance Factor for the Foam Produced with Chaser CD-1045 at Various Concentration in a SAG Process (1/3 PV, 70% Foam Quality, Test Core 10B, Pre-Foamer 3C).



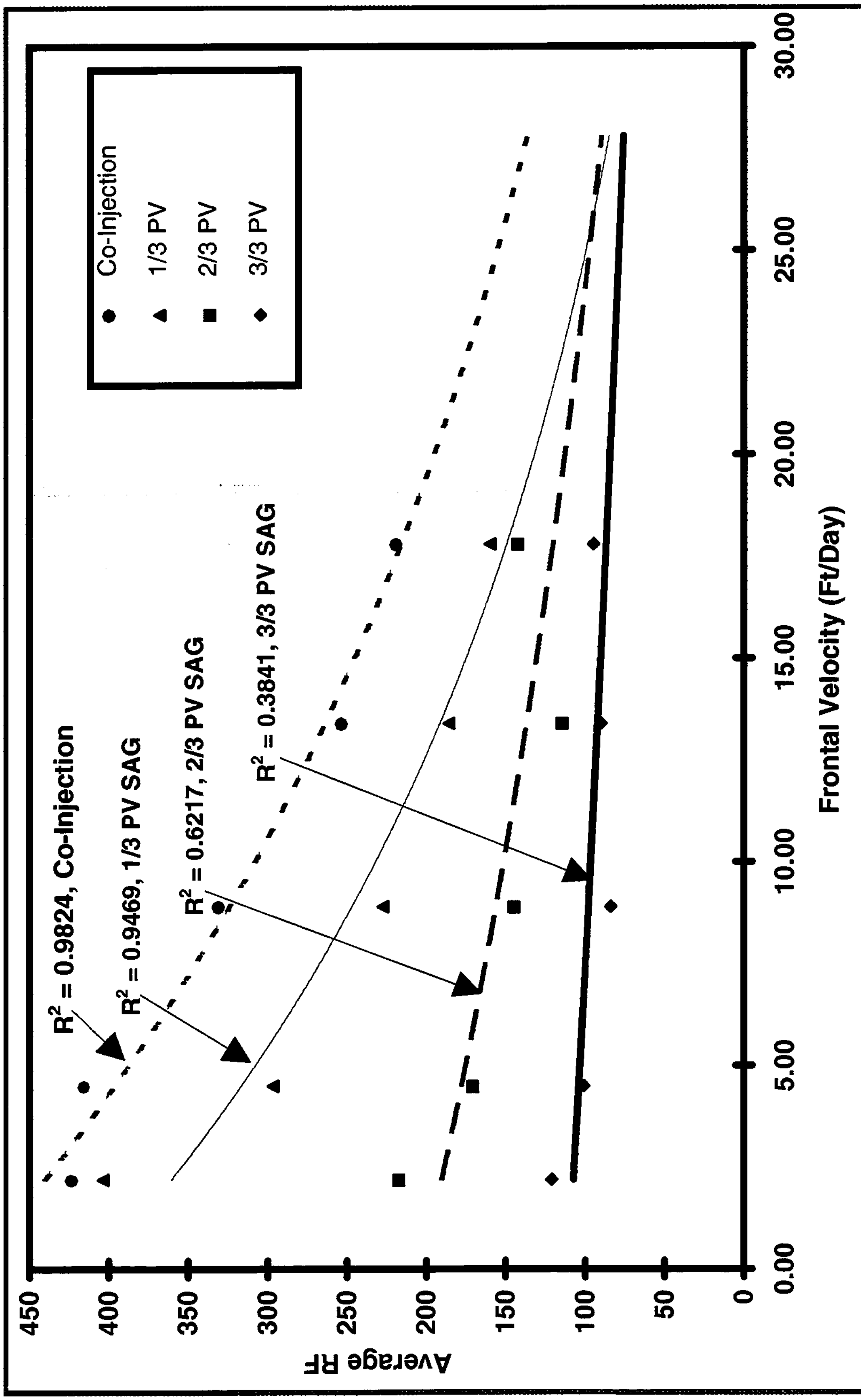
Comparison of the Co-Injection and SAG (Average of Last Cycle) Processes on the Performance of Foams Produced with 2500 ppm Chaser CD-1045 in South Cowden Brine (70% Foam Quality, Test Core 10B, Pre-Foamer 3C).

Figure 19



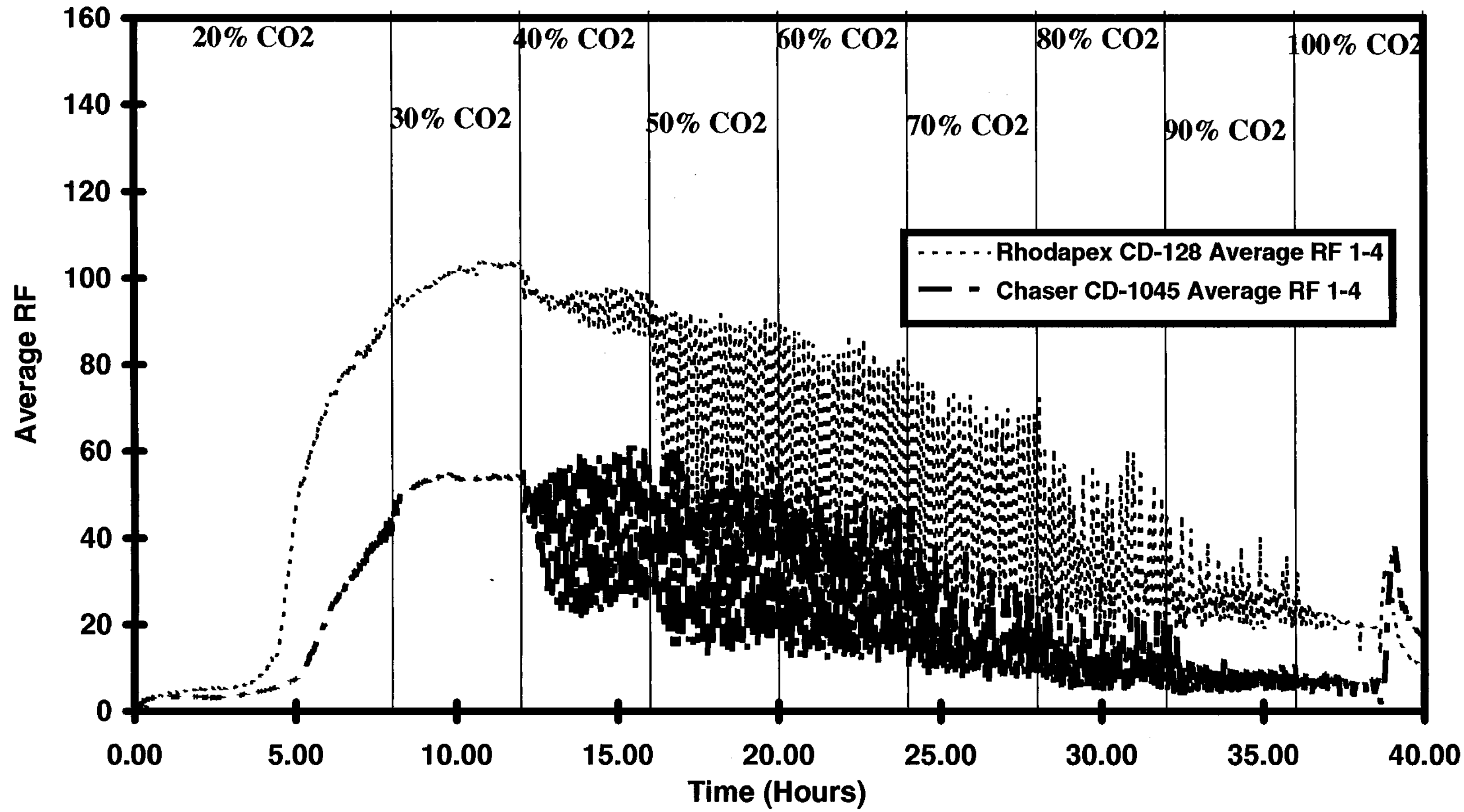
Effect of Frontal Velocity on Average Resistance Factor for the Foam Produced with Rhodapex CD-128 at Various Concentration in a SAG Process (1/3 PV, 70% Foam Quality, Test Core 10B, Pre-Foamer 3C).

Figure 20



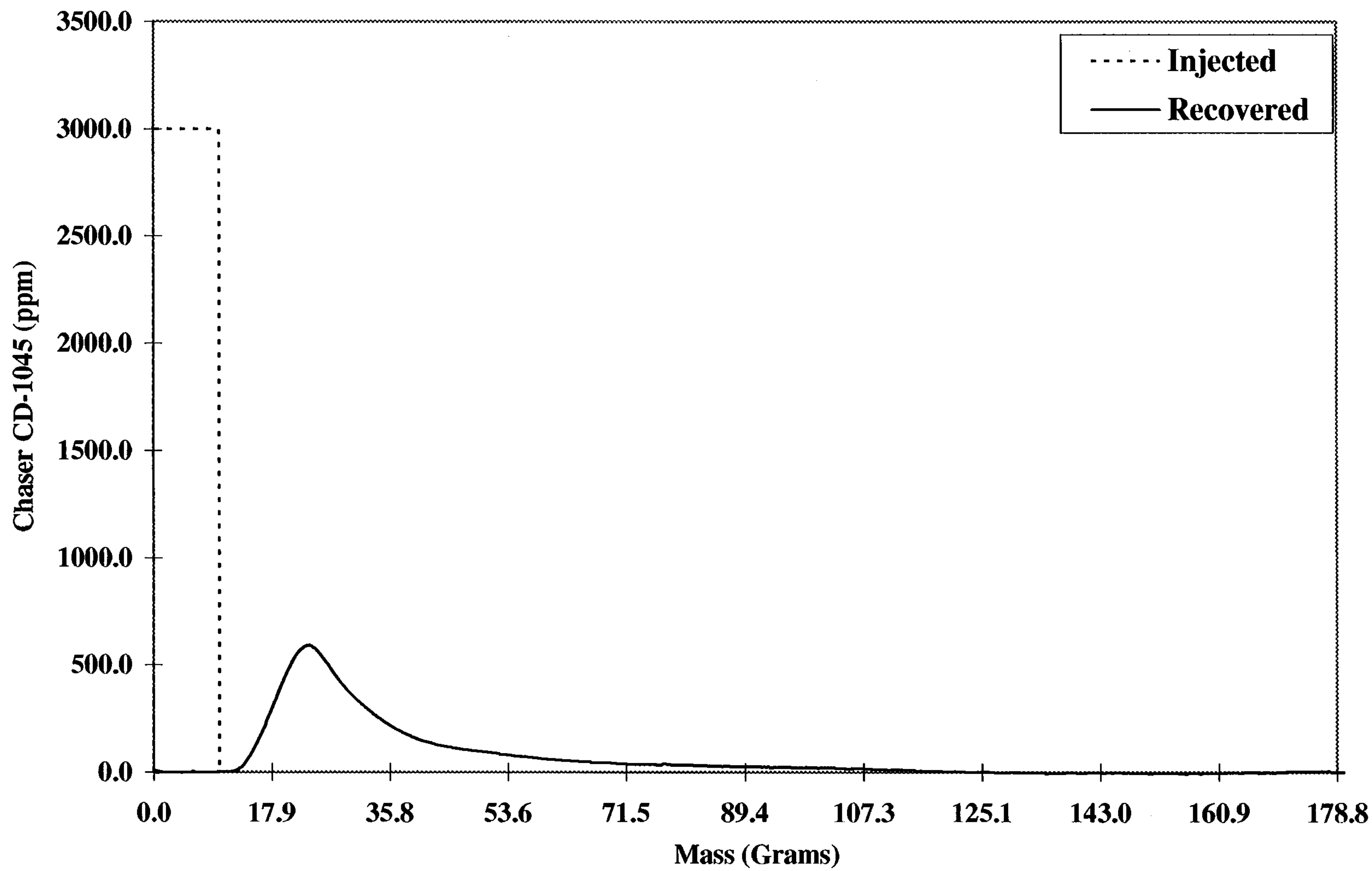
Comparison of the Co-Injection and SAG (Average of Last Cycle) Processes on the Performance of Foams Produced with 2500 ppm Rhodapex CD-128 in South Cowden Brine (70% Foam Quality, Test Core 10B, Pre-Foamer 3C).

Figure 21



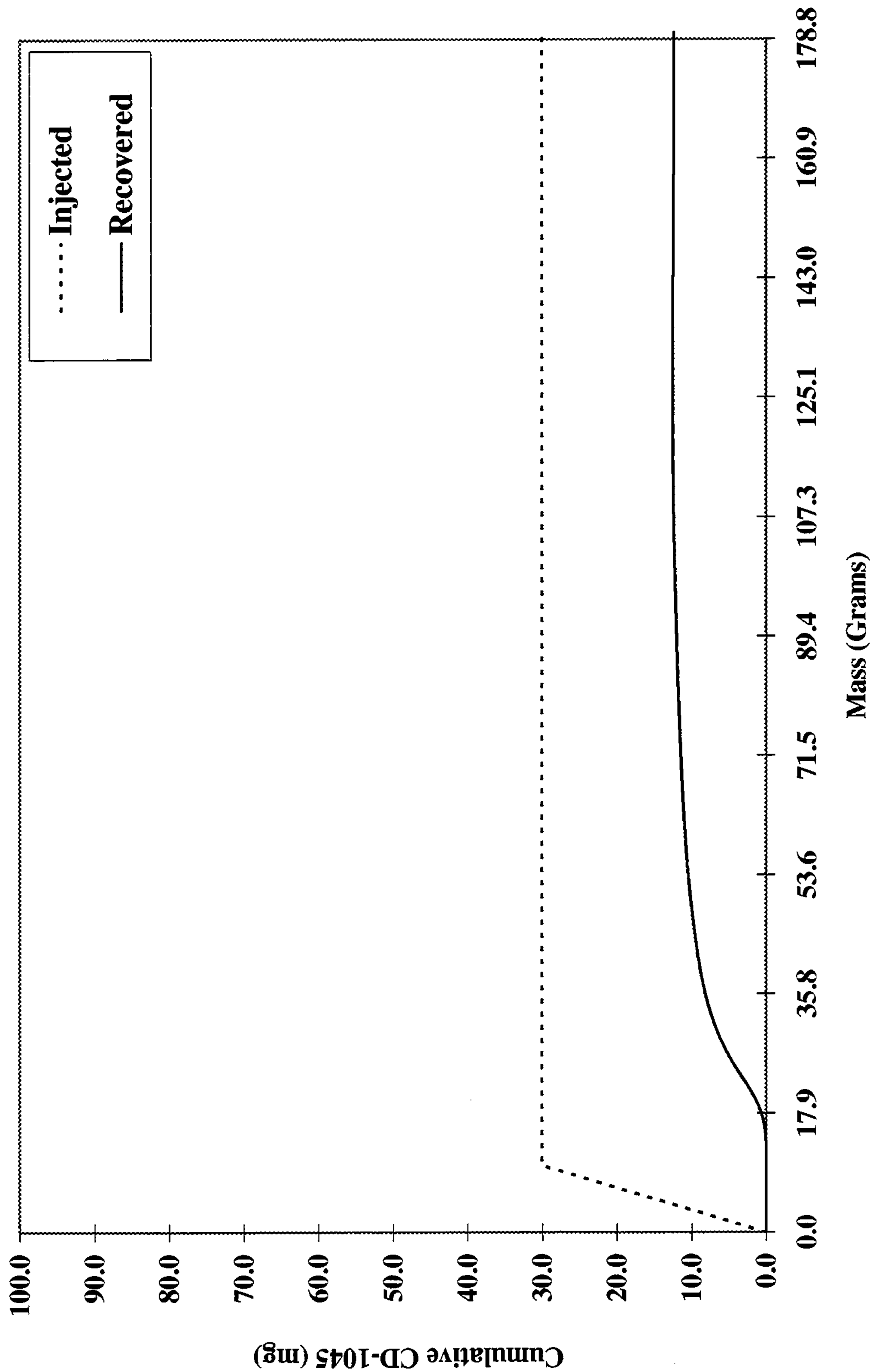
A Comparison for the Performance of CO_2-Foam Made with 2500 ppm Chaser CD-1045 or Rhodapex CD-128 in Synthetic South Cowden Brine as a Function of Foam Quality in A Field Core at Residual Oil Saturation (Test Core 12A, Pre-Foamer 10C).

Figure 22



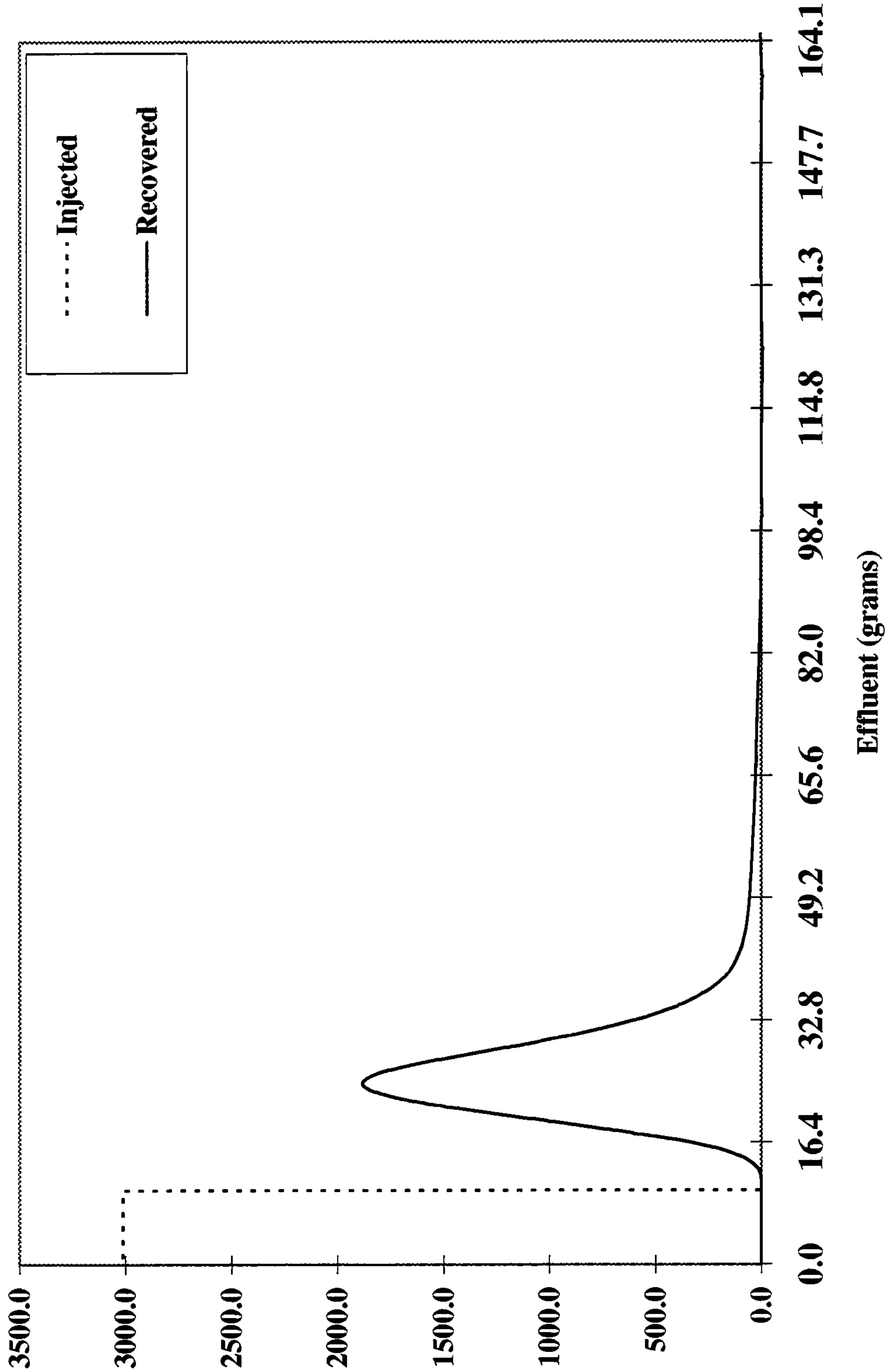
Adsorption Result (Refractometer Response) for the Injection of 10 Grams Chaser CD-1045 Solution (3000 ppm) in South Cowden Unit Brine in a Baker Dolomite Core.

Figure 23



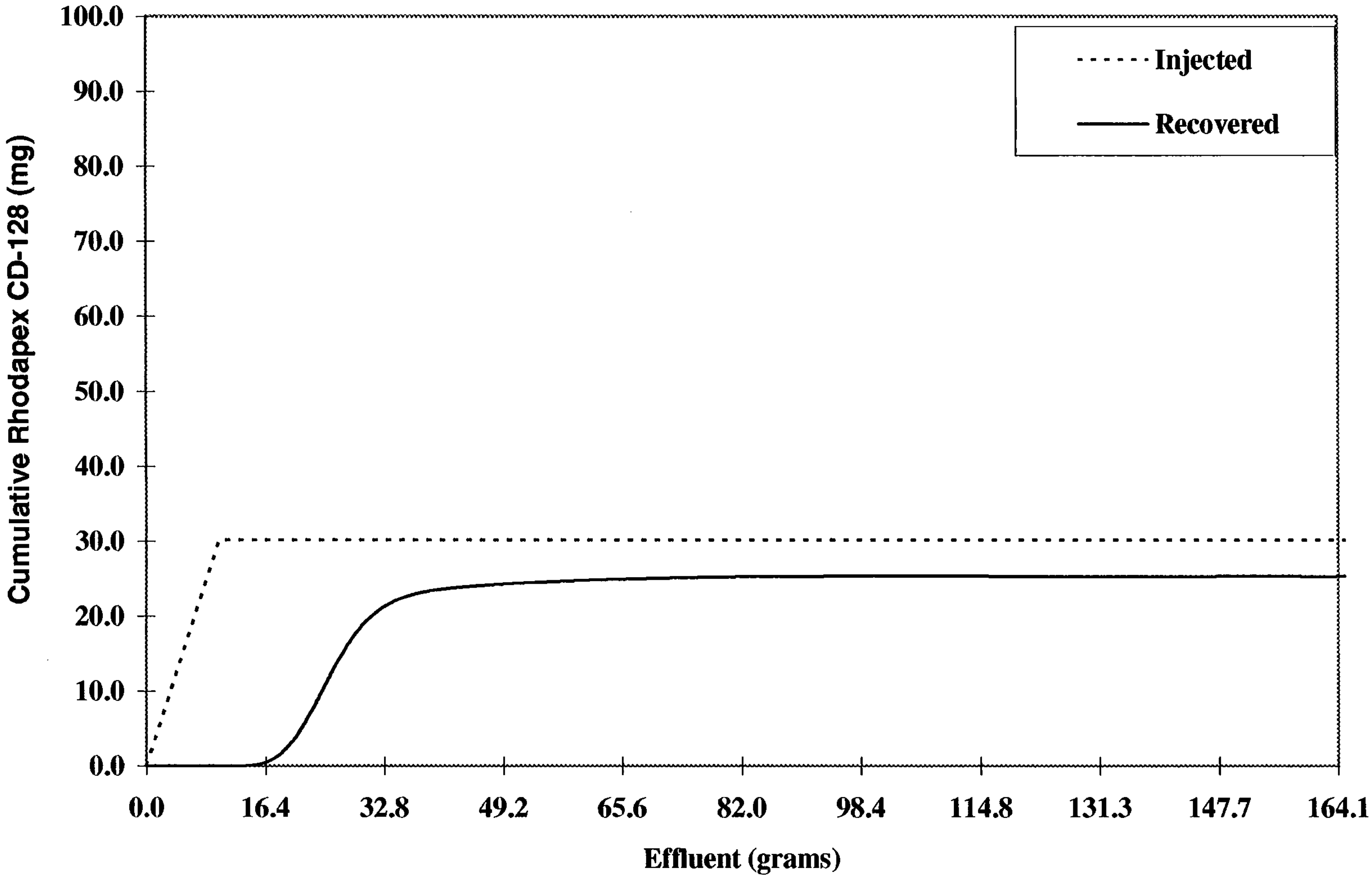
A Comparison of Cumulative Amounts of Recovered and Injected Chaser CD-1045 Solution in South Cowden Unit Brine in a Baker Dolomite Core (Refractometer Response).

Figure 24



Adsorption Result (Refractometer Response) for the Injection of 10 Grams Rhodapex CD-128 Solution (3011.3 ppm) in South Cowden Unit Brine in a Baker Dolomite Core.

Figure 25



A Comparison of Cumulative Amounts of Recovered and Injected Rhodapex CD-128 Solution in South Cowden Unit Brine in a Baker Dolomite Core (Refractometer Response).

Figure 26

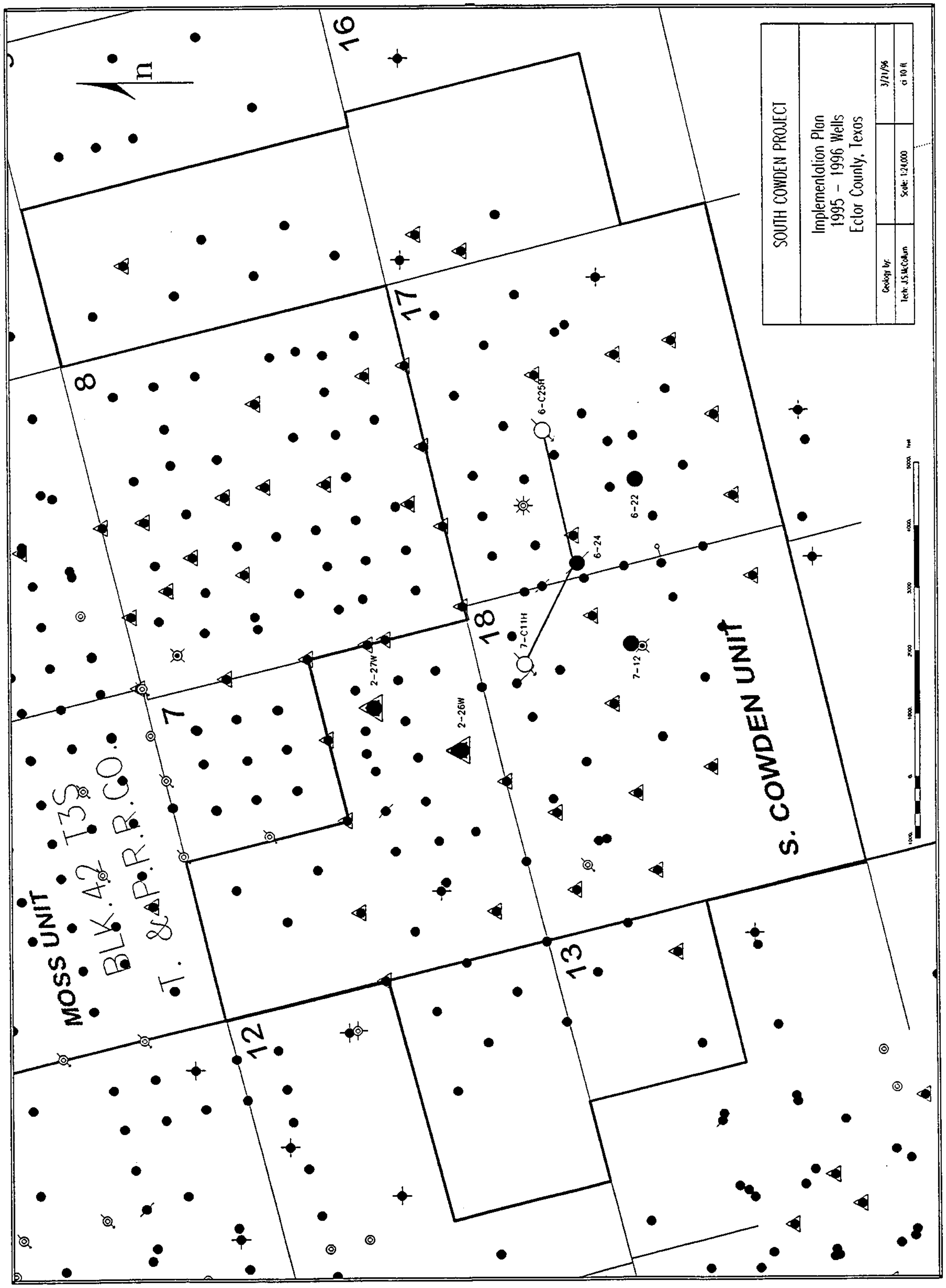

SOUTH COWDEN PROJECT
Implementation Plan
1995 - 1996 Wells
Ector County, Texas
Scale: 1:24,000
3/21/96
MOSS UNIT
S. COWDEN UNIT
BLK. 42 T3S
T. & P. R.R. CO.
16
17
8
18
7
12
13
6-C25R
6-22
6-24
7-C11H
7-12
2-27W
2-26W

Figure 27

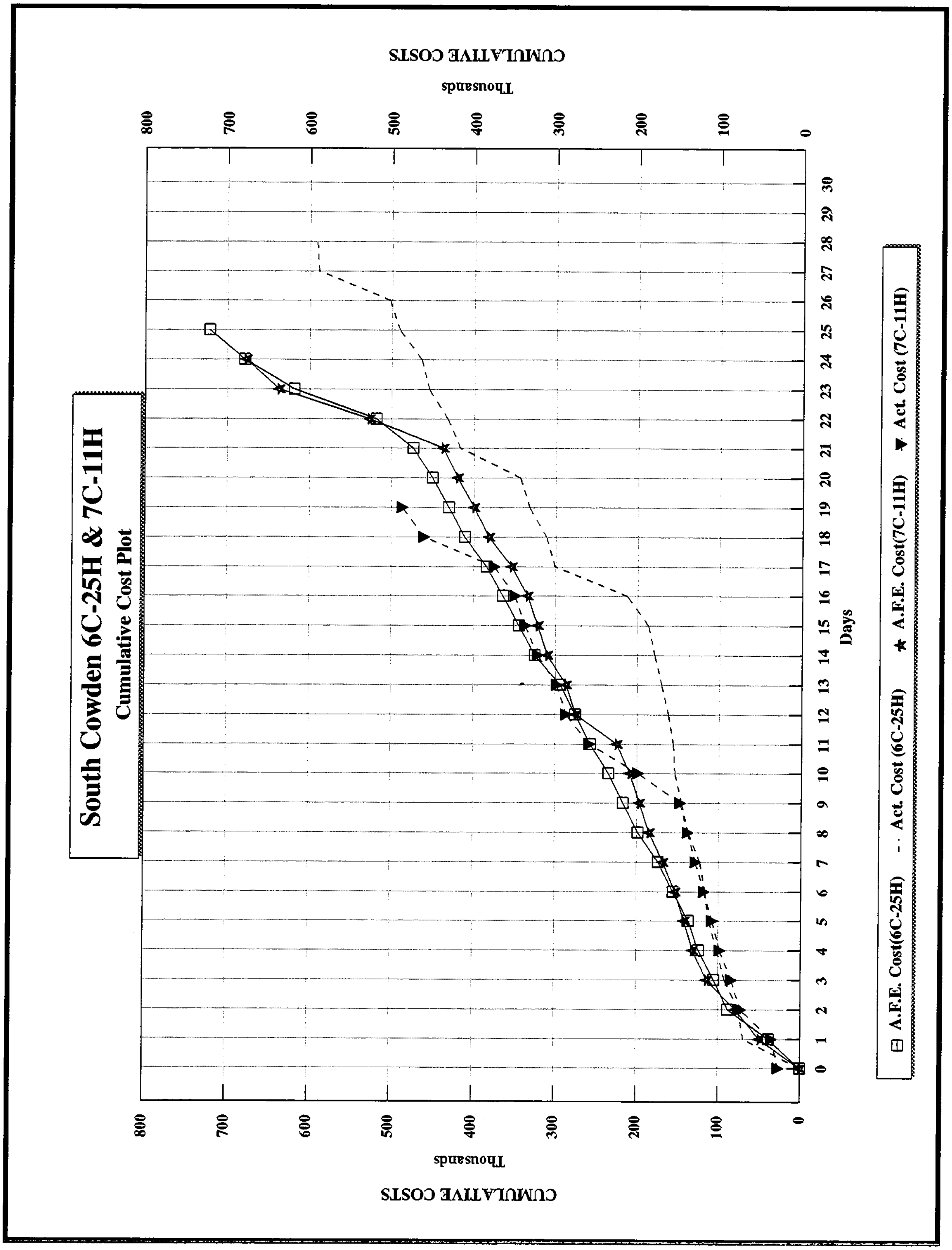

South Cowden 6C-25H & 7C-11H
Cumulative Cost Plot
CUMULATIVE COSTS
Thousands
Days
A.F.E. Cost(6C-25H)
Act. Cost (6C-25H)
A.F.E. Cost(7C-11H)
Act. Cost (7C-11H)

Figure 28

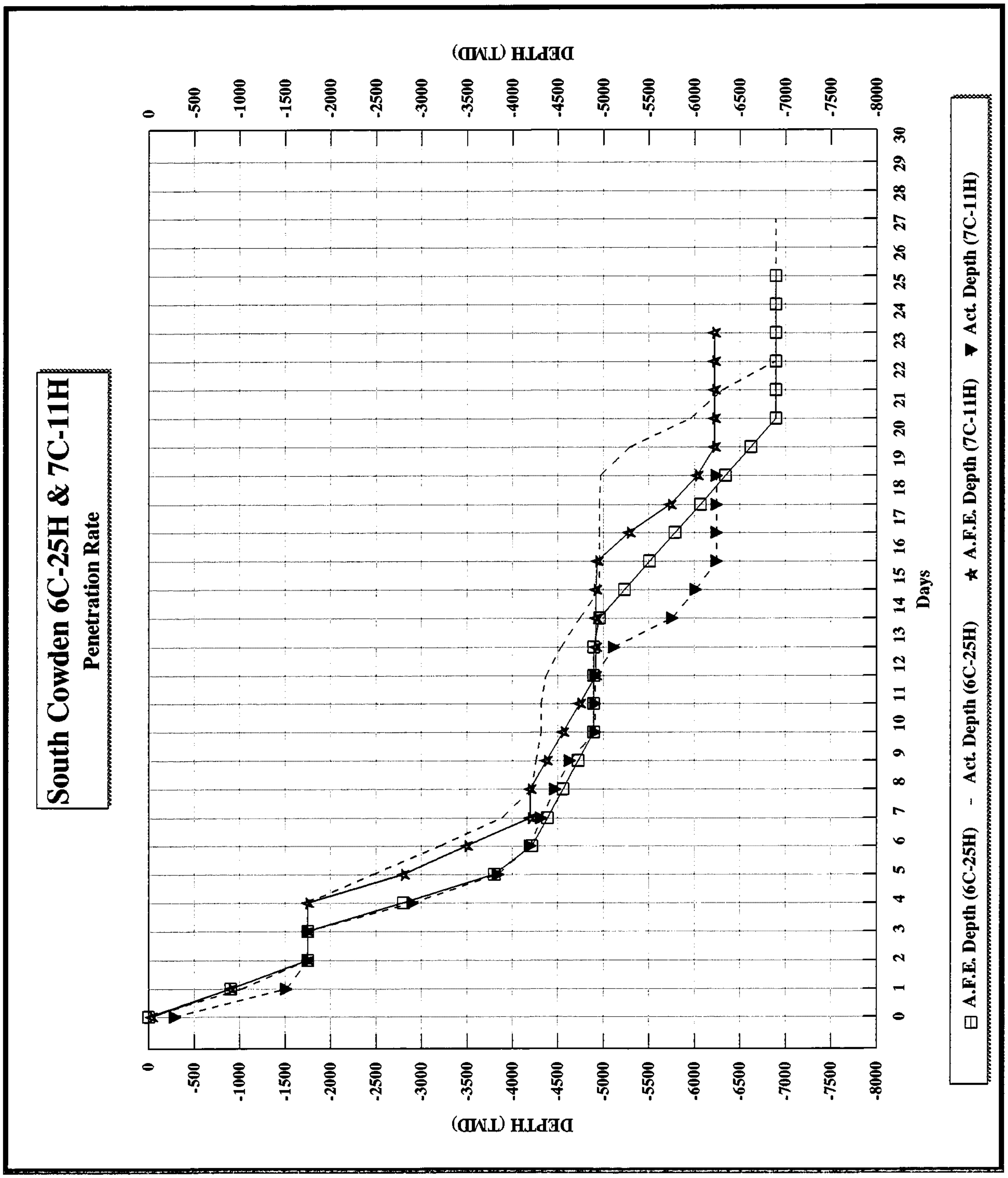
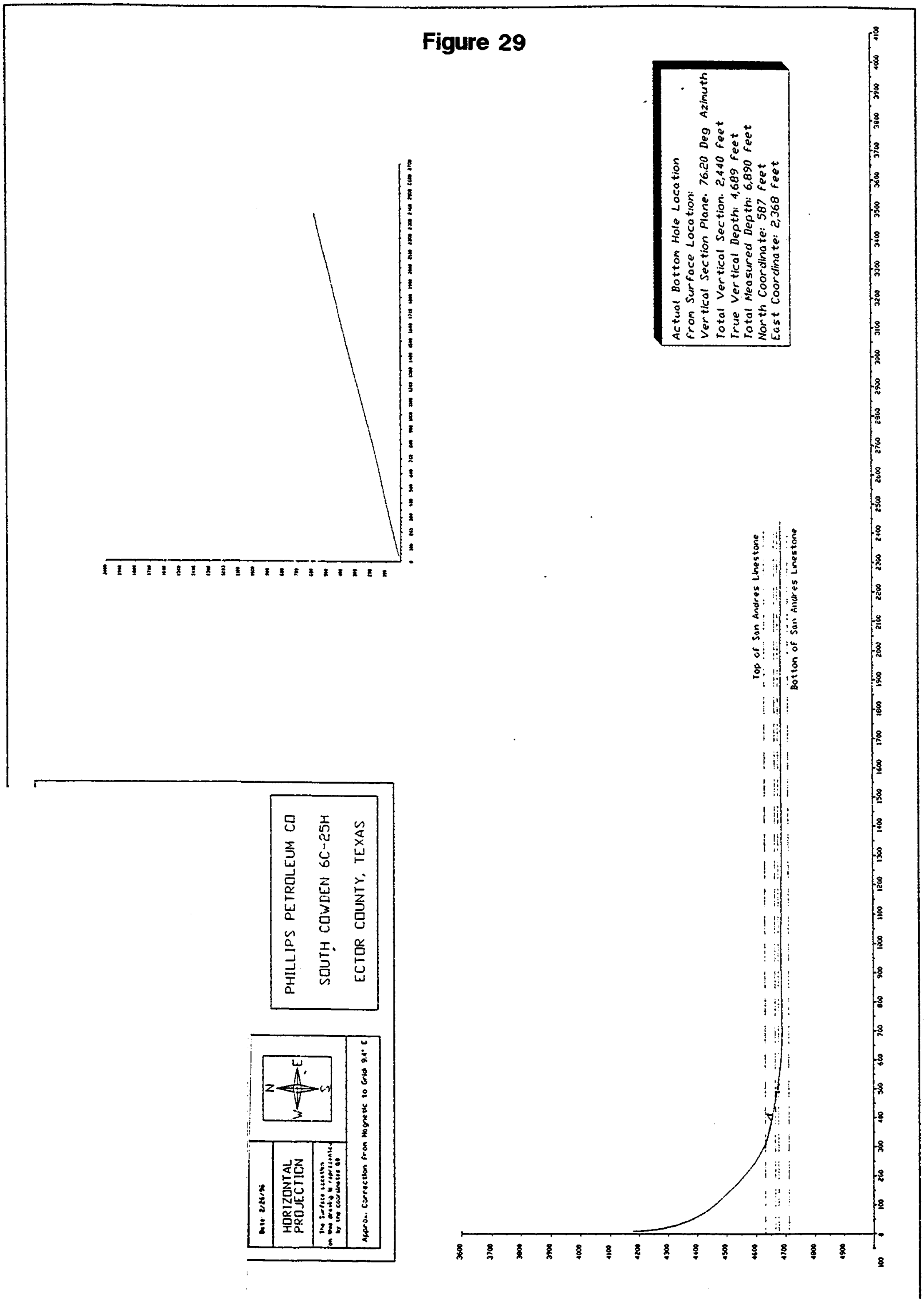
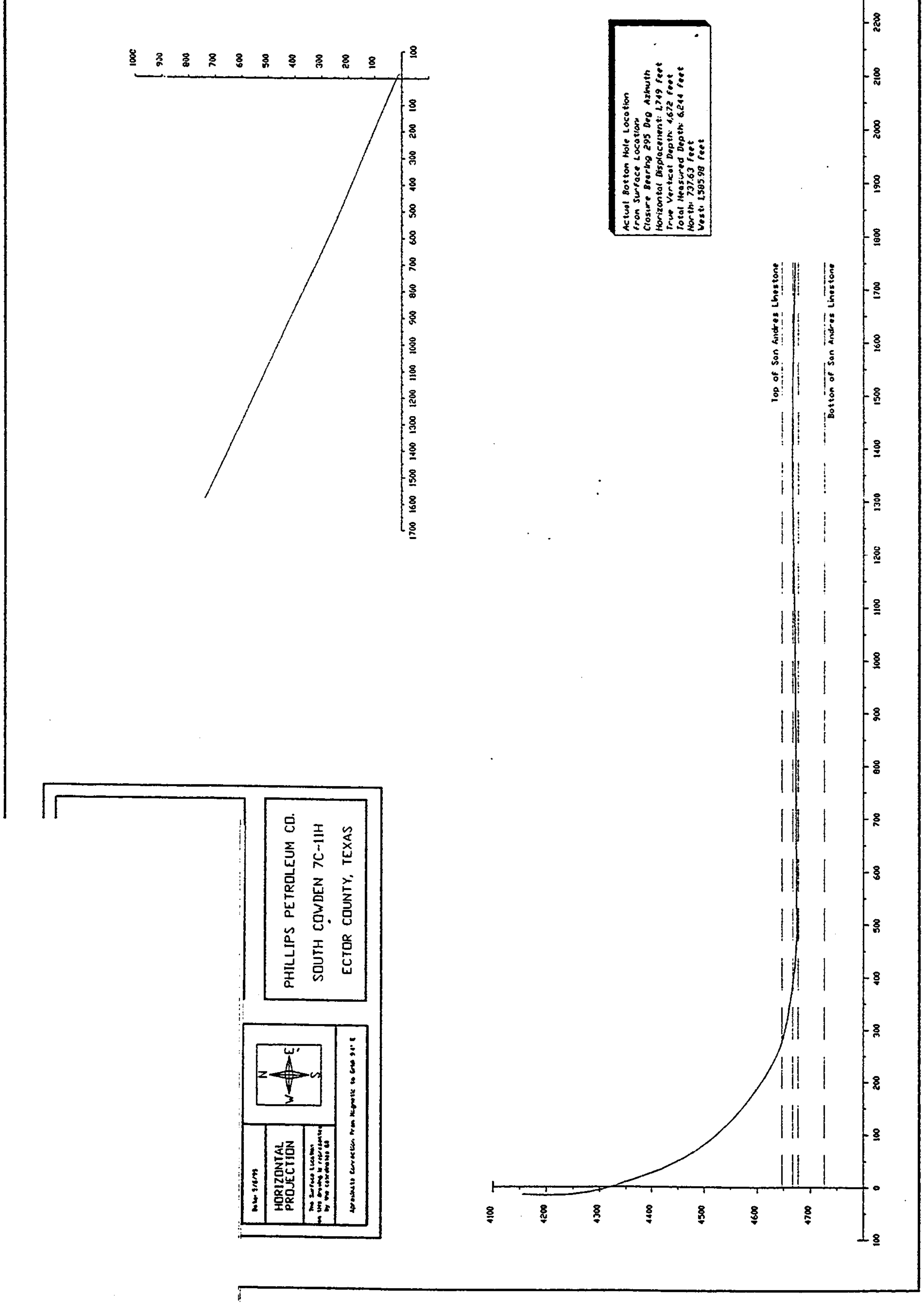

South Cowden 6C-25H & 7C-11H
Penetration Rate
DEPTH (TMD)
0
-500
-1000
-1500
-2000
-2500
-3000
-3500
-4000
-4500
-5000
-5500
-6000
-6500
-7000
-7500
-8000
Days
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
A.F.E. Depth (6C-25H)
Act. Depth (6C-25H)
A.F.E. Depth (7C-11H)
Act. Depth (7C-11H)

Figure 29



Actual Bottom Hole Location
From Surface Location:
Vertical Section Plane: 76.20 Deg Azimuth
Total Vertical Section: 2,440 feet
True Vertical Depth: 4,689 feet
Total Measured Depth: 6,890 feet
North Coordinate: 587 feet
East Coordinate: 2,368 feet
Top of San Andres Limestone
Bottom of San Andres Limestone
PHILLIPS PETROLEUM CO
SOUTH COWDEN 6C-25H
ECTOR COUNTY, TEXAS
HORIZONTAL PROJECTION
N
E
S
W

Figure 30

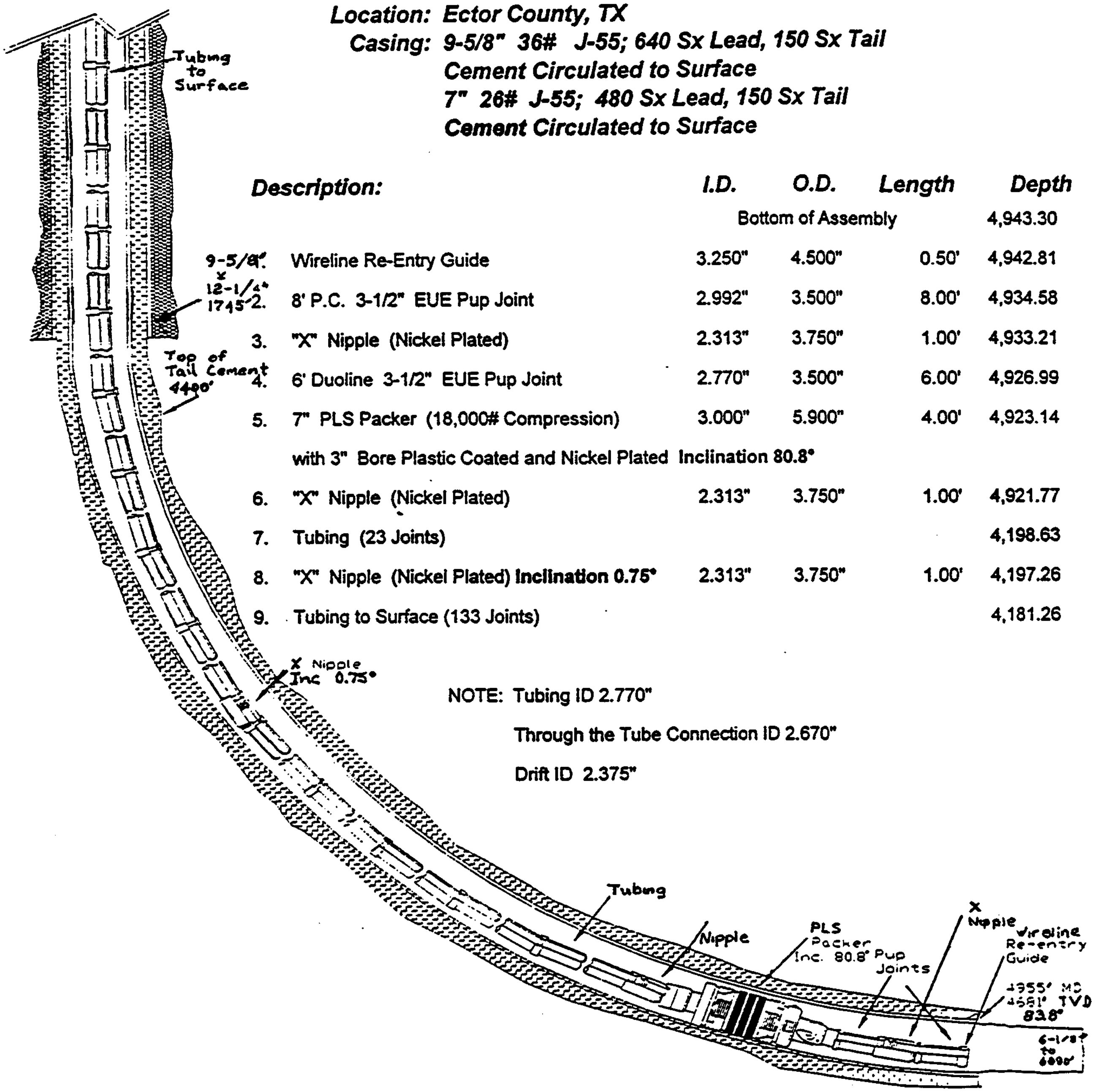


Actual Bottom Hole Location
from Surface Location
Closure Bearing 295 Deg Azimuth
Horizontal Displacement: 1,749 feet
True Vertical Depth: 4,672 feet
Total Measured Depth: 6,244 feet
North: 737.63 feet
West: 1,585.98 feet
Top of San Andres Limestone
Bottom of San Andres Limestone
PHILLIPS PETROLEUM CO.
SOUTH COWDEN 7C-11H
ECTOR COUNTY, TEXAS
HORIZONTAL PROJECTION
N
S
E
W

Figure 31

PHILLIPS

Well Name: ***South Cowden Unit #6-25H***
Location: ***Ector County, TX***
Casing: ***9-5/8" 36# J-55; 640 Sx Lead, 150 Sx Tail***
Cement Circulated to Surface
7" 26# J-55; 480 Sx Lead, 150 Sx Tail
Cement Circulated to Surface



	Description:	***I.D.***	***O.D.***	***Length***	***Depth***
		Bottom of Assembly			4,943.30
1.	Wireline Re-Entry Guide	3.250"	4.500"	0.50'	4,942.81
2.	8' P.C. 3-1/2" EUE Pup Joint	2.992"	3.500"	8.00'	4,934.58
3.	"X" Nipple (Nickel Plated)	2.313"	3.750"	1.00'	4,933.21
4.	6' Duoline 3-1/2" EUE Pup Joint	2.770"	3.500"	6.00'	4,926.99
5.	7" PLS Packer (18,000# Compression)	3.000"	5.900"	4.00'	4,923.14
	with 3" Bore Plastic Coated and Nickel Plated	**Inclination 80.8°**			
6.	"X" Nipple (Nickel Plated)	2.313"	3.750"	1.00'	4,921.77
7.	Tubing (23 Joints)				4,198.63
8.	"X" Nipple (Nickel Plated) **Inclination 0.75°**	2.313"	3.750"	1.00'	4,197.26
9.	Tubing to Surface (133 Joints)				4,181.26

NOTE: Tubing ID 2.770"

Through the Tube Connection ID 2.670"

Drift ID 2.375"

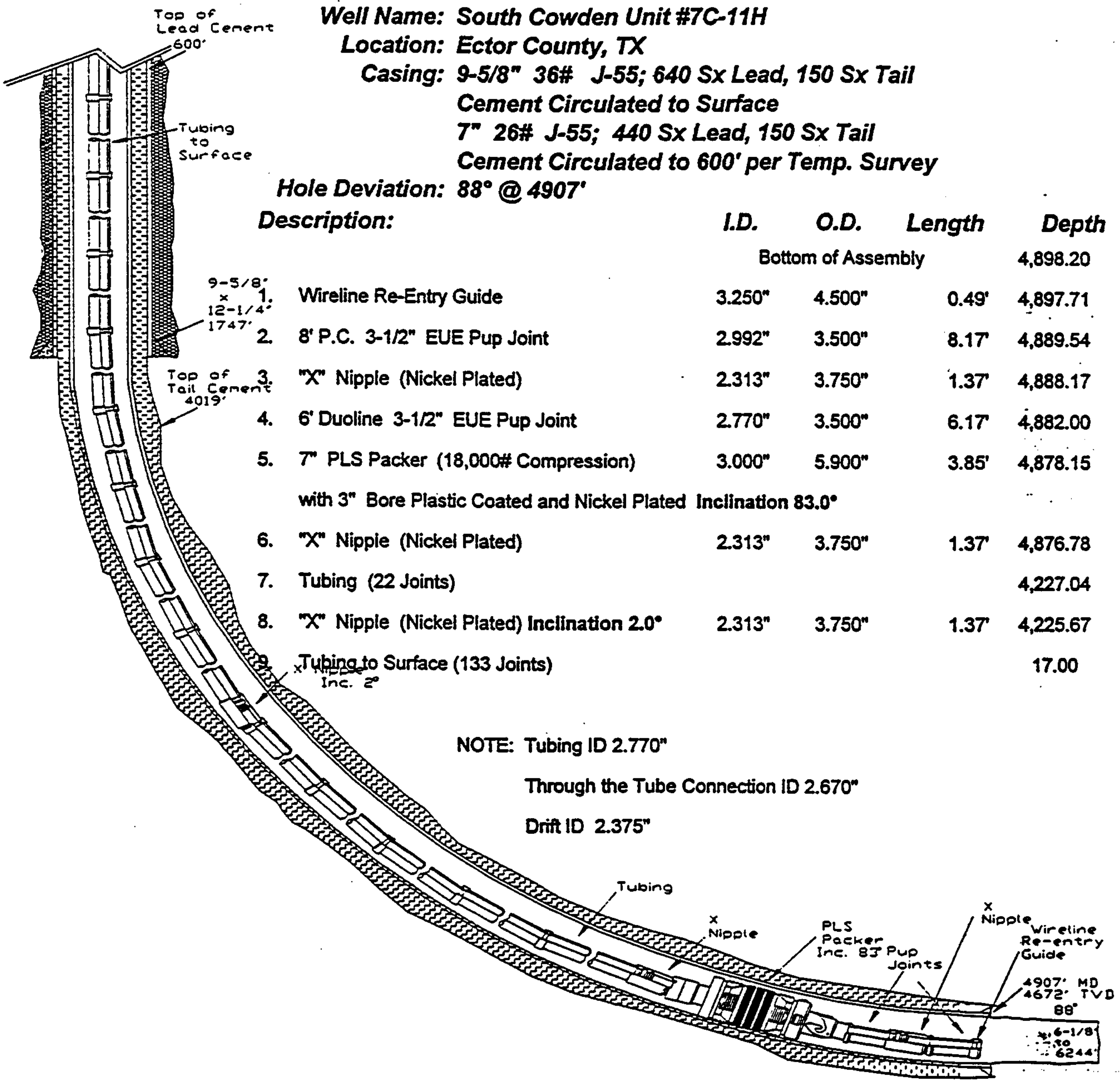
Figure 32

PHILLIPS

Well Name: ***South Cowden Unit #7C-11H***
Location: ***Ector County, TX***
Casing: ***9-5/8" 36# J-55; 640 Sx Lead, 150 Sx Tail***
Cement Circulated to Surface
7" 26# J-55; 440 Sx Lead, 150 Sx Tail
Cement Circulated to 600' per Temp. Survey
Hole Deviation: ***88° @ 4907'***

Description:		***I.D.***	***O.D.***	***Length***	***Depth***
		Bottom of Assembly			4,898.20
1.	Wireline Re-Entry Guide	3.250"	4.500"	0.49'	4,897.71
2.	8' P.C. 3-1/2" EUE Pup Joint	2.992"	3.500"	8.17'	4,889.54
3.	"X" Nipple (Nickel Plated)	2.313"	3.750"	1.37'	4,888.17
4.	6' Duoline 3-1/2" EUE Pup Joint	2.770"	3.500"	6.17'	4,882.00
5.	7" PLS Packer (18,000# Compression)	3.000"	5.900"	3.85'	4,878.15
	with 3" Bore Plastic Coated and Nickel Plated Inclination 83.0°				
6.	"X" Nipple (Nickel Plated)	2.313"	3.750"	1.37'	4,876.78
7.	Tubing (22 Joints)				4,227.04
8.	"X" Nipple (Nickel Plated) Inclination 2.0°	2.313"	3.750"	1.37'	4,225.67
9.	Tubing to Surface (133 Joints)				17.00

NOTE: Tubing ID 2.770"
Through the Tube Connection ID 2.670"
Drift ID 2.375"



LIST OF TABLES

TABLES

Table 1

SOUTH COWDEN UNIT PRODUCED BRINE ANALYSIS

CATION	CONC. (ppm)	ANION	CONC. (ppm)
Na	23933.0	Chloride	40600.0
K	445.0	Sulfate	3763.0
Ca	2547.0		
Ba	640.0		
Sr	55.0		
TDS	71870.0		

Table 2
Summary of Adsorption Tests in Baker Dolomite Cores

Run No.	Core No.	Residual Oil (y/n)	Sacrificial Agent	Surfactant Injected: Name	Conc. (ppm)	Solution Wt. (g)	Net Wt. (mg)	Amount Adsorbed Lbs/Acre-Ft: Refract.	TOC	Hyamine	Avg. Each Run	Overall Avg.	Comment No.
1	B-07	n	none	CD-128	1000.2	30.00	30.01	73.4	249.8	185.7	169.6		
2	B-06	n	none	CD-128	1991.5	15.00	29.87	-7.7	79.7	47.0	39.6		
3	B-05	n	none	CD-128	3011.3	10.00	30.11	132.9	112.1	25.0	90.0	99.8	1
4	B-09	n	none	CD-1045	1000.0	30.00	30.00	529.9	331.1	79.4	313.5		
5	B-08	n	none	CD-1045	1998.1	15.00	29.97	525.7	494.3	175.0	398.3		
6	B-03	n	none	CD-1045	2998.5	10.00	29.99	424.5	645.3	502.2	524.0		
7	B-12	n	none	CD-1045	2999.0	10.35	31.04	473.8	455.2	273.0	400.6		
8	B-04	n	none	CD-1045	3000.2	10.00	30.00	535.0	395.2	474.0	468.1	420.9	2
9	B-15	y	none	CD-1045	999.7	30.00	29.99	753.1	581.5	457.9	597.5		
10	B-14	y	none	CD-1045	2000.0	15.00	30.00	698.0	560.1	342.2	533.4		
11	B-13	y	none	CD-1045	2998.2	10.35	31.03	652.4	617.8	352.4	540.9	557.3	3
12	B-16	n	250 ppm HEC -25	CD-1045	2970.8	10.00	29.71	457.9	NM	435.3	446.6	446.6	4
13A	B-11	n	none	CD-128	2996.6	10.00	29.97	194.0	84.3	171.4	149.9	149.9	5
13B	B-11	n	none	CD-1045	2991.8	10.00	29.92	793.2	443.2	233.3	489.9	489.9	6

Comments

1. Average for Rhodapex CD-128 (no oil, no sacrificial agent)
2. Average for Chaser CD-1045 (no oil, no sacrificial agent)
3. Average for Chaser CD-1045 (residual oil, no sacrificial agent)
4. Average for Chaser CD-1045 (no oil, sacrificial agent is 250 ppm HEC-25)
5. Duplicate test for Run Number 2
6. Chaser CD-1045 following Rhodapex CD-128

TABLE 3

South Cowden Unit

Horizontal Injection Wells 6C-25H and 7C-11H

Design vs. Actual results

	6C-25H Design	6C-25H Actual	7C-11H Design	7C-11H Actual
DLS	12°/100'	10.96°/100' (AVG)	12°/100'	11.39°/100' (AVG)
Azimuth	76° East of True North	75.83° East of True North (AVG)	65° West of True North	65.27° West of True North (AVG)
KOP	4212'	4212'	4195'	4195'
Casing Placement	4684' TVD / 4889' TMD (81.2°)	4681' TVD / 4955' TMD (83°)	4671' TVD / 4915' TMD (86°)	4672' TVD / 4907' TMD (87°)
Csg Pt Deflection Length from Vertical	440'	462'	447'	476'
Curve Length	751'	743'	751'	775'
90° Lateral Depth	4706' TVD / 4963' TMD	4690.29' TVD / 5180' TMD	4672' TVD / 4945' TMD	4675' TVD / 4970' TMD
Lateral Length (measured from csg shoe)	2000'	1935'	1303'	1337'

NOTE: All depths are measured from the RKB height.
6C-25H surface elevation: 2934'
7C-11H surface elevation: 2935'
Surface locations were 70' apart

Table 4
South Cowden Unit Horizontal Injection wells
Bottom Hole Assemblies

Curve Section	Lateral Section
4 ½" premium drill pipe 16.6 #/ft (to surface)	3 ½" drill pipe S-135 13.3 #/ft (to surface)
X-over sub (3')	3 ½" "Hevi wate" drill pipe (1200')
4 ½" "Hevi wate" drill pipe 42 #/ft (900')	3 ½" drill pipe S-135 13.3 #/ft (3000')
X-over sub (3')	4 3/4" monel collar (32')
4 ½" Premium drill pipe 16.6 #/ft (1000')	4 3/4" monel collar (32')
6 ½" monel collar (30')	Float sub / orienter combo(4')
6 ½" monel collar (32')	4 3/4" Positive Displacement Pump 1.25° deflection (22') Designed for rotating and sliding
Float sub (3')	6 1/8" tungsten carbide 3 coned bit Modified for directional drilling (1')
6 3/4" Positive Displacement Pump 1.25° deflection (22')	
8 3/4" tungsten carbide 3 coned bit Modified for directional drilling (1')	

NOTE: Monel collars were utilized in the drillstring to eliminate MWD magnetic interference. The MWD system is set within the collars of the drillstring.

LIST OF ATTACHMENTS

Attachment	Description
I	Abstract submitted entitled "Laboratory Evaluation of Surfactants for CO_2-Foam Applications at South Cowden Unit".
II	Abstract submitted entitled "Incorporation Production and Petrophysical Data to Improve Predictivity History Matching for a CO_2 Flooding Project at South Cowden Unit, West Texas".

ATTACHMENTS

ATTACHMENT I

LABORATORY EVALUATION OF SURFACTANTS FOR CO_2-FOAM APPLICATIONS AT SOUTH COWDEN UNIT

Ahmad Moradi-Araghi, E. L. Johnson, D. R. Zornes and K. J. Harpole

An extensive laboratory study was conducted to evaluate foaming ability of four surfactants, Chaser ® CD-1045, CD-1050, Rhodapex ® CD-128 and Foamer ® NES-25 were tested in South Cowden Unit (SCU) cores. The objective of this study was to identify suitable surfactants to produce stable CO_2-foam for possible application at SCU for mobility control and diversion of CO_2 in horizontal injection wells. This study is part of a Department of Energy (DOE) Class II demonstration project, partly funded by DOE.

Several core tests were performed with foams produced by co-injection of surfactant solutions at various concentrations in a synthetic SCU brine, and CO_2 under about 2000 psi of pressure and 98^{N} F at 20-90% foam quality. All field cores (diameter: 1", length: 4-6") used in this study were highly inhomogeneous with significantly varying permeability in different sections of the core. A typical core which was equipped with three pressure taps along its length exhibited permeabilities of 10 to 600 md in its four sections. The resistance factors (RF) determined for flowing the foam in each section of the core appeared to vary with the permeability of that section. The foams exhibiting this behavior were referred to "smart foams" by J. P. Heller. Resistance factors measured for CO_2-foams produced in the same core with the four surfactants under identical conditions showed the best performance equally for Chaser CD-1050 and Rhodapex CD-128, followed by Chaser CD-1045 and Foamer NES-25 which were also comparable. However, Rhodapex CD-128 and Chaser CD-1045 were chosen for further studies based on availability and previous field experience. RF values measured for the foams produced with these surfactants at various concentrations maximized between 50% to 70% foam quality. The maximum, however, shifted to higher foam qualities with increased surfactant concentration.

The chosen surfactants were secondly evaluated each by co-injection as well as SAG (Surfactant Alternating with Gas) processes to investigate the effect of surfactant concentration and frontal velocity. The resulting foams exhibited a shear thinning behavior with resistance factors increasing with surfactant concentration. The performance of the foams produced by the SAG process with both surfactants in the same core at 70% foam quality diminished with slug size.

Both chosen surfactants evaluated for their CO_2-foam properties in a test core at residual oil saturation produced lower RF values than the tests performed in cores with practically no movable oil to CO_2 flow. These tests which were performed at varying frontal velocities and foam quality, also showed the shear-thinning property and dependency of RF values on foam quality. This data coupled with adsorption tests being carried out presently in our laboratory, should help in selecting Rhodapex ® CD-128 or Chaser ® CD-1045 as candidate surfactant.

ATTACHMENT II

INCORPORATING PRODUCTION AND PETROPHYSICAL DATA TO IMPROVE PREDICTIVE HISTORY MATCHING FOR A CO_2 FLOODING PROJECT AT SOUTH COWDEN UNIT, WEST TEXAS

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The South Cowden Unit is one of three mid-term demonstration projects being conducted under the DOE Class II Oil Program for shallow-shelf carbonate reservoirs. The South Cowden project is designed to demonstrate the technical and economic viability of horizontal CO_2 injectors to improve CO_2 project economics for small fields approaching abandonment.

Extremely heterogeneous permeability distributions make it difficult to match individual well performance in simulations of carbonate reservoirs. Yet individual well performance matching can be critical if the simulation model is to be used to optimize injection and production well placement in a CO_2 flood development plan. Detailed petrologic study of core often provides the best information on reservoir flow properties, but cores are rarely available in sufficient quantity to map permeability and porosity variations throughout an entire field. In South Cowden field, variations in permeability within the dominant rock type are too complex to be represented by a single permeability-porosity transform. This project saw an improvement in the reservoir description by integrating information from individual well production histories with the core and well log data.

Core data established a relationship between permeability and total fluid producing rate. Total fluid producing rate was mapped across the field, and used to compute permeability from the well log porosity. A 3-D model of permeability and porosity was interpolated from the well log data, which was then used to construct the reservoir simulation model. This approach resulted in a marked improvement in individual well matches of oil and water production rates. The simulation model was used with greater confidence to quantify CO_2 flood performance for a number of development schemes.