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DESIGN AND IMPLEMENTATION OF A CO_2 FLOOD UTILIZING ADVANCED RESERVOIR CHARACTERIZATION AND HORIZONTAL INJECTION WELLS IN A SHALLOW SHELF CARBONATE APPROACHING WATERFLOOD DEPLETION

Annual Report for the Period
June 3, 1994 to October 31, 1995

By
L. D. Hallenbeck
K. J. Harpole
M. G. Gerard

May 1996

Performed Under Contract No. DE-FC22-94BC14991

Phillips Petroleum Company
Odessa, Texas

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

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ABSTRACT

The work reported here covers Budget Phase I of the project. The principal tasks in Budget Phase I are the Reservoir Analysis and Characterization Task and the Advanced Technology Definition Task. Completion of these tasks have enabled an optimum carbon dioxide (CO_2) flood project to be designed and evaluated from an economic and risk analysis standpoint. Field implementation of the project has been recommended to the working interest owners of the South Cowden Unit (SCU) and approval has been obtained.

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 requirements, CO_2 purchase price tied to West Texas Intermediate (WTI) crude oil price) and gas recycle agreements (expensing cost as opposed to large capital investments for compression) were negotiated to further improve project economics.

A detailed reservoir characterization study was completed by an integrated team of geoscientists and engineers. The study consisted of detailed core description, integration of log response to core descriptions, mapping of the major flow units, evaluation of porosity and permeability relationships, geostatistical analysis of permeability trends, and direct integration of reservoir performance with the geological interpretation. The study methodology fostered iterative bidirectional feedback between the reservoir characterization team and the reservoir engineering/simulation team to allow simultaneous refinement and convergence of the geological interpretation with the reservoir model. The fundamental conclusion from the study is that South Cowden exhibits favorable enhanced oil recovery characteristics, particularly reservoir quality and continuity.

Detailed core descriptions were made of two full cores and several partial cores from the South Cowden Unit. Core information from the contiguous Emmons and Moss Units were also incorporated into the study. The core study concluded that reservoir quality in the South Cowden Unit is controlled primarily by the distribution of a bioturbated and diagenetically altered rock type with a distinctive "chaotic" texture. The "chaotic" modifier derives from the visual effect of pervasive, small-scale intermixing of tan oil-stained reservoir rock with tight gray non-reservoir rock.

The Grayburg-San Andres section is divided into multiple zones based on the core study and gamma ray markers that correlate wells across the unit. The type log for South Cowden Unit Well No. 8-19 is shown in Figure 8. Each zone is mapped as continuous across the field. 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.

Repeat Formation Tester (RTF) measurements indicate good vertical pressure communication between Zones D and E, fair communication with Zone F, and poor communication with Zone C. The lower part of Zone F is separated from Zone E by a thin silty dolomite layer, which may hinder efficient vertical sweep between the two zones. Zone C is effectively isolated from the zones above. Open-hole hydraulic fracture tests indicate a strong tendency for induced fractures to grow downward from the productive zones to Zone A, a high permeability, water bearing grainstone layer.

Understanding of reservoir rock distribution, identification of vertical pressure barriers within the reservoir (especially relative to the oil-water contact), and recognition of the nature of hydraulic fracture propagation in the reservoir were critical to the formulation of the CO_2 flood development plan. Horizontal water alternating gas (WAG) injection wells will be placed downstructure in Zones D and E, which are above the oil-water contact throughout the project area and which do not have internal vertical pressure barriers. Vertical WAG injection wells will be placed upstructure, where Zone C is above the oil-water contact, but isolated by a vertical pressure barrier from the CO_2 sweep in Zones D and E. Perforation of the lower part of Zone F in the vertical injectors will compensate for the potential inefficiency of vertical sweep across the weak pressure barrier between Zone F and Zone E. Injection pressures in both horizontal and vertical WAG injectors will be kept below the fracture gradient (0.58 psi/ft) to minimize CO_2 losses to deeper, nonproductive zones.

A full-field reservoir simulation model was 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 the SCU on the north. The model grid and layering were laid out to conform to the geological configuration of the reservoir. Porosity, permeability, and flow properties of the major reservoir facies identified by the reservoir characterization team were incorporated into the model. An iterative, "predictive" history matching approach was employed whereby the team was directly involved in making refinements to the model reservoir description until the model was able to accurately predict historical waterflood performance. This predictive approach provides added confidence in future performance forecasts.

Critical laboratory data on CO_2/oil phase behavior, minimum miscibility pressure, and oil recovery efficiency were matched and incorporated into the model. The model was then used to evaluate various alternative CO_2 project development scenarios, including the optimum use of horizontal CO_2 injection wells. The most attractive project development alternative incorporates both horizontal and vertical CO_2 injection wells to conform to the reservoir geology and maximize sweep effeciency and oil recovery. This configuration is presented as the Authority for Expenditure (AFE) Base Case development plan.

EXECUTIVE SUMMARY

In June of 1994 Phillips Petroleum Company received a financial assistance 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 in late October of 1995. 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 and evaluated, and an Authority for Expenditure (AFE) for project implementation to be generated and submitted to the working interest owners. Budget Phase II will consist of implementation and execution of the project in the field. Phase II will terminate in January of 2001.

At this writing the Reservoir Analysis and Characterization Task and the Advanced Technology Definition Task have been completed as intended. A project development plan has been generated. This plan along with the associated costs and production forecast have been utilized to evaluate the project economics and risk analysis. An AFE has been prepared and approved after review by the working interest owners. Field implementation of the project will be initiated in late October of 1995.

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 cost associated with the 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 open up CO_2 flooding as an economically viable recovery technology option for smaller SSC reservoirs and for independent operators.

Project Description

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

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

The general approach includes CO_2 flooding the South Cowden Unit with horizontal injection wells from a centralized area. Preliminary studies indicate that significant investment cost reduction can be obtained through lower overall drilling costs (less wells), significant cost reduction from reduced surface injection line requirements, and reduction in re-injection costs. Improved sweep efficiency from the horizontal injection wells are expected to result in increased 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 are also developed. Advanced reservoir characterization has been essential in optimizing the final project design. At the conclusion of the project, a complete methodology for economically tertiary flooding small SSC reservoirs will be established that will allow other operators to implement similar strategies for their own fields.

Summary of Progress

A CO_2 flood project for the SCU has been designed, evaluated, proposed to the working interest owners and approved for field implementation. Field implementation of the project development plan is scheduled to begin in late October of 1995.

Work on the project was initiated in June of 1994. The primary end result sought from the Reservoir Analysis and Characterization Task was development of a three dimensional (3-D) geologic reservoir description. Work on numerous subtasks had to be completed or largely completed to develop this reservoir description. These subtasks are listed in the Table of Contents. An adequate reservoir description was assembled in early 1995 to initiate simulation studies for project design and performance forecasting.

The second task which had to be accomplished in order to propose the project was the Advanced Technology Definition Task. Reservoir simulation studies for project design and performance forecasting were initiated upon generation of a workable 3-D geologic reservoir description. The reservoir description and special laboratory studies were key input data required for the simulation model. Following verification of the simulation model through history matching work, simulator runs were used to select the design of the horizontal well scheme and generate the optimum well location and injection scheme for the project development plan. A premise team then generated investment and operating costs along with an implementation schedule for the development plan. The production and cost forecasts were then utilized to generate an economic and risk analysis evaluation of the project. An Authority for Expenditure (AFE) was generated and presented to the working interest owners in September of 1995. This AFE has been approved and field implementation of the project is scheduled to begin in late October of 1995.

DISCUSSION

Reservoir Analysis and Characterization

The project Statement of Work (SOW) contains nine primary subtasks in the Reservoir Analysis and Characterization task. Progress on these nine subtasks is discussed on the following pages in the order given in the SOW.

Process and Interpret 3-D Seismic Data

The South Cowden Unit (SCU) three dimensional (3-D) seismic survey was processed internally by Phillips Petroleum. The digital data was sent to Phillips Odessa office and was loaded onto an interpretation workstation. Several sonic logs were also loaded onto the workstation so that synthetic seismograms could be generated. The synthetics were used to tie the well log tops with the seismic data. Based on the synthetic ties, four seismic horizons that correspond to major formation tops were interpreted: Yates, Queen, Grayburg, and San Andres. Seismic time structure maps were generated for each horizon and were compared to the geologic contour maps (based on the well tops for all available wells under the 3-D data). In each case, agreement between the geophysical and geologic maps was quite good.

Seismic trace data culled from the 3-D survey was plotted at normal well log scale and displayed next to a gamma log to give a measure of seismic resolution. Although this was a high resolution seismic survey, the resolution at the San Andres level is on the order of 150 to 200 feet.

Further work on seismic modeling is covered later in this report in the section on Advanced Geostatistical Studies. The end result of this work is that stochastic data integration techniques are not considered in this instance a viable option in generating a 3-D porosity model for this reservoir unit. The low signal-to-noise ratio of the relative amplitude seismic sections at the reservoir unit also preclude the use of seismic inversion in this case which can yield the impedance variation and subsequently, the porosity variation in the reservoir unit on the 15 foot to 20 foot resolution scale.

Injection Well Condition Database

All injection well surveys were reviewed and tabulated for percentage injection into each stratigraphic layer and any losses above or below the defined layers. There are 75 surveys among 24 injectors. Results from this work are given in Table I. In the project area, the injection into the chaotic interval correlated well with the reservoir simulation results. Because of the large number of historical surveys the decision was made to not proceed with additional surveys as had been originally planned.

Drill, Test, and Complete Two Reservoir Characterization Wells

SCU Well 6-23

This well was spudded July 13, 1994 and drilled to a total depth (TD) of 4900 feet. The interval 4548-4785' was cored, recovering 237 feet of core. At TD, the well was logged with compensated density and neutron logs, dual focused resistivity logs, sonic, gamma-ray, and dielectric logs. Eight formation pressure measurements were made using a wireline formation test tool. A microfracture test was conducted which determined the formation parting pressure to be 2608 psi, equivalent to 0.55 psi/ft. fracture gradient. An acoustic borehole imaging log showed the top of the fracture at 4680', within the basal 20 feet of the reservoir interval (D zone), and continuing downward to the base of the well. The fracture appeared to initiate in the oolitic grainstone in zone A, at 4790 feet.

The well was completed by perforating the interval 4603-4652', in zones E and F (Fig. 1). The well was stimulated with 2000 gal. 20% hydrochloric acid (HCl) without observing a pressure break during treatment. This zone was placed on production at a rate of 3 barrels of oil per day (BOPD) and 186 barrels of water per day (BWPD) pumping.

SCU Well 6-21

This well was spudded July 26, 1994 and drilled to a total depth of 4900 feet. The interval 4600-4776' was cored, but only 102 feet were recovered, and much of the core was broken up. A microfracture test was conducted with the well at 4776 feet, before penetrating the grainstone in zone A. The fracture initiation pressure in this test was 2717 psi, a fracture gradient of 0.58 psi/ft. The acoustic imaging log was not logged below 4735' because of an obstruction in the wellbore, but showed the fracture to extend from 4699' down below the base of the logging run. Following the microfracture test drilling was resumed to TD. Open hole logs were run, consisting of compensated density and neutron logs, dual focused resistivity logs, spectral gamma ray, sonic, and dielectric logs.

The well was completed by perforating the interval 4665-4698', in zone F (Fig. 2). The well was stimulated with 1500 gal. 20% HCl acid. This zone produced 4 BOPD and 452 BWPD on pump, and was temporarily abandoned. The intervals 4558-4572' and 4624-4632' were perforated and treated with 3000 gal. 20% HCl acid. This zone was placed on production at a rate of 20 BOPD and 13 BWPD.

Conventional Core Results

Conventional core analysis has been completed for the two new wells. In SCU Well 6-21 a total of 176 feet of core was cut and 102 feet recovered. A total of 102 analyses were completed for this well, including 35 plug analyses of broken core. In SCU Well 6-23 a total of 237.5 feet were cut with 100% recovery. A total of 238 analyses were completed; 8 of these were plug analyses and the remainder whole core analyses. The laboratory analyses included measurements of porosity, two horizontal and one vertical permeability, grain density, and fluid saturations using a Dean-Stark method. The cores were photographed in ultraviolet (UV) light prior to analysis, and slabbed and photographed in white light following analysis.

Evaluation of Unit Production History and Waterflood Response

Prior to analysis of the waterflood performance the completion intervals and methods were verified for the majority of wells in an extended project area (1 - 2 wells outside the identified project area). A total of 66 wells have been reviewed in detail. This consisted of reviewing each individual well file and noting any pertinent data such as drill date, depth of shows, completion depth and method, initial production (IP) and pressures. An IP map (Fig. 3) was generated as a first attempt to distinguish relative better portions of the Unit.

Information was similarly collected for each workover job sequentially performed on the well noting job size and treating rates and pressures. Workover date and job were identified on an oil/gas/water production plot to assist in evaluation of the job effectiveness. Each sequential addition to the completion interval(s) was so noted on a log copy to assist in zone correlation and cross sections. In summary the following information (if available) was combined during the well review:

- sequential summary of workover events
- production plot with workover notations
- log copy with sequential completion intervals marked
- wellbore sketch

The purpose of reviewing the well files was to verify the wells were similarly completed and thus, rule out at least one possible reason for any waterflood performance discrepancies. The waterflood performance itself was analyzed using a computer software package, **Production Analyst (PA)**, designed for this purpose and loaded with the individual well production data. This database consisted of month-by-month oil/gas/water production and water injection volumes for each SCU well since unitization. **PA** allows both manipulation and visualization of the data. For SCU, the most useful information came from analyzing 1) the first three years of the waterflood during which the injection was relatively constant and 2) the cumulative oil production map. From the first three years it is apparent which wells responded quickest to water injection, the injectors responsible for this response (Fig. 4), which producers had minimal water injection response and which producers had water breakthrough first. This was secondary insight to the better portions of the Unit and the first view of the well-to-well interconnections in the reservoir. This performance was later re-evaluated because the increased unit production in 1996-1968 reflected changing production well allowables and not waterflood response as previously interpreted. First waterflood response occurred in 1970-1974 after waterflood fill-up. Re-evaluation of this time period showed similar results to the prior analysis (Fig. 4 and 5). In short, the best area of the unit contained both the better producing wells (i.e., those still rate constrained when the waterflood started) and those which responded first to water injection.

The cumulative oil production during the waterflood years was mapped (Fig. 6). This again provided insight as to the "sweet" and "dead" spots of the Unit. Experience has shown that a CO_2 flood has less chance of success in areas that were not successfully waterflooded.

Core Description and Petrographic Studies

Work on this subtask focused on the macroscopic and microscopic description of four, South Cowden Unit Grayburg cores and one Moss Unit Grayburg core. Macroscopic description of core from the SCU 8-19 (470'), 7-10 (249'), and 8-11 (170') is complete. Additionally, the reservoir intervals in the SCU 6-23 and Moss Unit 16-14 were described macroscopically.

Thin section (t.s.) samples from the SCU 8-19 (97 t.s.), 7-10 (63 t.s.), 6-23 (15 t.s.), and 8-11 (12 t.s.) and the Moss Unit 16-14 (11 t.s.) were described and point counted. Thin section description and point counting provide mineral and porosity percentages and information about depositional texture, diagenesis, and pore types. Mineral content also was determined by x-ray diffraction (XRD) analysis. Twenty-four, twenty, and thirteen samples from the SCU 8-19, 7-10, and 8-11 respectively, were analyzed using XRD.

Eleven rock types, defined from core studies, were grouped into five major lithofacies:

(1) Fusulinid-peloid dolopackstone (open-marine outer ramp),
(2) Ooid-peloid dolograinstone (high-energy offshore shoals),
(3) Mottled peloid dolopackstone (shallow outer to inner ramp),
(4) Sandy dolopackstone (shallow inner ramp), and
(5) Fenestral dolopackstone (tidal flat).

These lithofacies are predominantly dolomite. The first three lithofacies listed above have trace to minor amounts of anhydrite, and rocks of the Fenestral Dolopackstone Lithofacies commonly contain greater than 25% anhydrite. Sandy dolopackstones are 10 to 40% very fine- to fine-grained detrital quartz and feldspar.

The cored Grayburg Formation and lower part of the overlying Queen Formation form a thick regressive sequence composed of several, smaller scale transgressive/regressive cycles. Fusulinid-peloid dolopackstone typically forms the lower part of these cycles and records outer ramp deposition. The upper part of the cycles is commonly inner ramp sandy dolopackstone. Some sandy dolomites may record reworking of mixed siliciclastic/carbonate sediments during the initial stages of the following marine transgression.

The SCU reservoir interval is composed of rocks of the Mottled Peloid Dolopackstone

Lithofacies. These rocks display a distinctive gray/tan color mottling due to variations in oil staining. Tan oil-stained areas are bioturbated. These areas are commonly 2 to 8+ cm. across and equant to vertically elongate with long dimensions up to a few tens of centimeters. Gray, lower porosity interburrow areas lack oil staining and are generally slightly smaller than the associated tan areas. Core plugs were taken from the tan and gray areas to determine the petrophysical properties of these dolomites. Twenty-one plugs were taken from the 8-19 core. Seventeen, twenty-seven, and fourteen plugs were taken from the 7-10, 6-23 and 8-11 cores, respectively.

Gray dolomite samples (dolowackestones and dolopackstones) generally have 2 to 9% porosity and 0.002 to 2 md permeability. Porosity is moldic and intercrystalline. Core plugs of the tan oil-stained dolomite typically have porosities ranging from 10 to 32% and permeabilities ranging from 2 to 400 md. Tan areas are dolopackstone, washed dolopackstone, and dolograinstone. Porosity in the tan areas is intergranular, moldic and intercrystalline. The open fabric of some tan areas suggests possible anhydrite dissolution.

SCU reservoir porosity is a function, at least in part, of the relative amounts of tan and gray dolomite. The amount of intergranular and intercrystalline anhydrite cement also has a significant effect on reservoir porosity in some wells. Decreased porosity in the northwestern part of SCU may be related to increased anhydrite cementation. The observed increase in anhydrite and corresponding decrease in porosity in the SCU 8-11 and Moss Unit 16-14 samples support this idea.

The original depositional texture and fabric of the mottled peloid dolopackstone markedly affect permeability. Despite similar porosities, the very finely crystalline tan dolomite of the 7-10 has markedly lower permeability (av. 10 md) than the medium crystalline tan dolomite of the 8-19 (av. 175 md) or 6-23 (av. 90 md). Very finely crystalline tan dolomites which characterize the SCU 7-10 appear to have formed from the dolomitization of muddier sediments than the sediments composing the tan dolomites of the 8-19 or 6-23.

Thin, laterally continuous sandy dolopackstone layers are used to divide the reservoir interval at SCU into four zones (C-F). The sandy dolopackstone layers at the base of Zone F and the base of Zone D have relatively low permeabilities and may partially restrict CO_2 movement between Zones F and E and D and C, respectively. By contrast, low-porosity layers in the reservoir interval dominated by the gray dolomite are generally 20 to 30% porous tan dolomite and should not markedly restrict the vertical movement of CO_2 through the reservoir interval.

Pore Geometry Measurements

There is a strong correlation between laboratory measurements of pore geometry and other indicators of reservoir quality such as permeability. The variation in pore geometry properties for selected samples taken from three wells in the South Cowden field also is strongly linked with lithofacies descriptions such that the major lithofacies groupings have distinctive pore geometry properties.

Pore size distributions are generated from Nuclear Magnetic Resonance (NMR) relaxation time measurements on 100% water-saturated core plugs. The resultant distribution of relaxation times is directly scaled into pore dimensions, where fast relaxation times correspond to small pores and slower relaxation times are associated with larger pores. The relaxation time/pore size distributions are statistically evaluated for comparison with other properties. Mercury porosimetry intrusion or drainage curves provide information about the distribution of pore throats or the connectors between larger pore bodies.

The pore size and throat size distributions for many of the samples selected from wells 8-19, and Emmons 146 and 135 tend to be broad with a wide range of sizes, often with the distribution slighly skewed towards the larger pores and throats. The higher quality reservoir lithofacies, washed dolograinstones and dolopackstones, have smaller sorting indices and more log normal distributions of pore body and throat sizes. The smaller sorting index indicates a narrower range of pore sizes, often what is absent is the largest pore sizes that are contributed by moldic porosity. For all samples there are strong correlations between average relaxation time, or pore radius, and sample permeability. There is also good correlations between pore throat radius and permeability. These measurements of pore body size provide the basis for a good permeability estimator that is better than generally obtained for carbonate reservoirs.

Geological-Petrophysical Interpretation of Stratigraphic Framework

Regional Geology

In an effort to learn more about the overall geologic structure of the South Cowden Field, and to relate it to the regional geology of the Central Basin Platform, several sources of data have been utilized. A geologic structure map of a middle Grayburg marker was generated using Geologic Data Service (GDS) well log picks. The logs were correlated by GDS geologists, and the resulting picks have been made available to the industry. The structure map (generated by Phillips geologists) covers acreage located beyond the boundaries of the 3-D seismic survey, particularly to the north of the survey in Unocal's Moss Unit, and to the Southwest in a field operated by Conoco. This map confirms that the South Cowden structure is located just to the east of the Central Basin Platform, and that the structural high is located along the leaseline between the South Cowden and Emmons Units. Since the GDS structure map was generated using different picks than those established for this reservoir characterization study, the map should only be used to show general structural trends (Figure 7).

Phillips personnel attended the Bureau of Economic Geology's (BEG) annual meeting to review the final results of their South Cowden Field Study. The BEG study provided a regional geologic setting for much of the eastern margin of the Central Basin Platform. Several cross sections along the eastern side of the platform were constructed using cored wells so that log and core data could be used to develop their sequence stratigraphic framework. These sections were discussed at the meeting, and copies were given to companies participating in the consortium.

Synthetic seismograms were generated for several wells in the area and were used to tie regional two dimensional (2-D) seismic data to geologic well tops. The seismic data and the well logs were used simultaneously to generate a regional geologic interpretation. The San Andres/Grayburg reservoir appears to be draped over a Glorieta age sediment high. The Texas Bureau of Economic Geology (BEG) believes that the Glorieta sediments were deposited as a submarine fan complex to the east of the Glorieta margin.

Stratigraphic Framework

The stratigraphy of the San Andres has been divided into eight layers, labelled A through H (Fig. 8). These layers were chosen based on the gamma ray (GR) log for the SCU 8-19 well. The top of each layer is represented by a "kick" on the GR log that appears to be correlatable across the South Cowden, Emmons, and Moss Units. These "kicks" appear to be induced by changes in lithology. Based on what was seen in the 8-19 core, the GR log is deflected when there is an increase in quartz sand. These thin sandy beds may be chromostratigraphic markers, but this is not certain. These layers differ somewhat from the rock types since the rock types are based on foot by foot core descriptions. The core revealed minor changes in the rock that cannot be detected by the log or at least are not consistent from log to log. In order to define the stratigraphy of the South Cowden Field, consistent GR log picks are absolutely necessary. Some comments on the key layers are given below:

Layer Comment

- H The base of this layer, known as the Cowden Sand, marks the top of the San Andres.
- G The layer is a tight interval that provides the seal for the reservoir.
- F The top of the layer marks the top of the "chaotic" zone. Porosity improves with depth.
- E This is the main reservoir interval and the rock type is "chaotic".
- D The lower two thirds of the layer are tight and separate the layer from underlying porous rocks.

Well Log Correlation

The eight stratigraphic markers that subdivide the reservoir interval have been correlated on all available well logs located within the boundaries of the South Cowden 3-D survey -- over 225 wells (Fig. 9). Computer contoured geologic structure maps and gross isopach maps have been made for each of the subunits to check data quality (QC) the log picks. Since log correlation errors are expressed as striking contour anomalies on these maps, identification of wells for recorrelation was rather simple. After recorrelation, new contour maps were generated to insure that the correlation problems had been solved.

Two cross sections (one north-south and one east-west) were made through the Moss Unit to study how the porosity of the reservoir interval changes in relation to changes in structure. The same eight markers were correlated for nearly 30 Moss Unit well logs. It was hoped that this study would provide greater understanding of porosity changes within the South Cowden Unit. Although the study showed that porosity decreases to the north, it did not fully explain the porosity changes within the project area.

Permeability-Porosity Correlation for Rock Types

The numeric codes for the rock types in the core description for the SCU 8-19 well were loaded and merged with the well log data and the core porosity and permeability data. Most of the core analysis for this well was conducted on plugs rather than whole core. The resulting scattered data did not adequately represent the relationship between porosity and permeability, particularly for the Chaotic rock facies of the major productive zones.

Statistical distributions of core permeability and porosity for 20 wells were analyzed for each of the major stratigraphic zones in the reservoir, and confirmed that each zone could have a different porosity or permeability cutoff, representing the varying reservoir quality in each zone. Areal variations in rock quality were also confirmed, which would contribute to the range of cumulative production recorded for individual wells.

Re-Normalization of Old Neutron Logs

Digital data for 57 wells with modern logs and 92 wells with older neutron or sonic logs from the South Cowden, Emmons, and Moss Units were loaded on a UNIX computer for log interpretation. The 80 wells with single-detector count-rate neutron logs were originally normalized to modern compensated neutron log porosity measurements using a strictly statistical technique. Such normalization is most reliable when a thick stratigraphic section of consistent lithology and porosity is available for normalization. The 200 foot section above the Cowden Sand would meet these criteria. However, the older wells were completed by setting casing at depths ranging from 100 feet above the Cowden Sand to 30 feet below the Cowden Sand, then drilling through the pay zone and leaving an open hole completion, which was sometimes shot with nitroglycerine. Steel casing with a cement annulus causes a sharp deflection of the uncompensated neutron log, so cased and uncased intervals of the well would have different statistical measurements, and would need to be normalized separately. Therefore, the open-hole reservoir interval posed a particular problem for normalization, because average porosity and the thickness penetrated varies from well to well.

The simulation efforts using the first set of net pay and average porosity maps revealed some discrepancies between the distribution of hydrocarbon pore volume and the actual production from the wells. Although much of the discrepancy is attributed to permeability variations, the normalization of the old neutron logs was re-examined. Maps of the statistical mean, maximum, and minimum neutron reading within the reservoir interval were useful to identify the most obvious data problems (Fig. 10, 11, and 12). Some of these were related to large washouts in wells shot with nitroglycerine; these data intervals were excluded from the input data to the 3-D model. Every well was reviewed individually, comparing the maximum and minimum porosity readings in the reservoir interval with offset wells. Normalization shifts of the neutron curves were performed on 37 wells or about 50% of the wells with old neutron logs.

Porosity Computations

A multi-mineral porosity computation was performed for the 63 wells that had a modern well log suite, consisting of compensated density and neutron logs, sometimes augmented with a sonic log or a photoelectric curve. Based on petrologic work, the major mineral constituents of the reservoir interval are dolomite, anhydrite and sand (a mixture of quartz and feldspar). Effective log measurements of the mineral endpoints were chosen to match the core porosity measurements in SCU wells 8-19, 7-10, 8-11, 6-21 and 6-23. A correlation crossplot is shown in Figure 13, and the log interpretation parameters are listed in Table II. These parameters were used to compute porosity for each of the wells with modern logs, and show good agreement with other core porosities available for some of the wells.

The remaining 90 wells had limited porosity data consisting of normalized gamma-neutron logs, sonic logs, or sidewall neutron logs. Regression equations were developed for each of these logs vs. core porosity measurements (Fig. 14, 15, and 16). Porosity for the reservoir interval was computed for each well using the appropriate transform equation. A separate set of transform equations were developed for the non-reservoir interval above the Cowden Sand, using computed porosity from the modern logs as the standard because little core data was available for this interval. Shale corrections were not made, because the petrologic studies showed no true shale beds in the reservoir.

Permeability

Petrologic work identified the "chaotic" rock type as the dominant reservoir facies in the field. The oolitic grainstone facies was the only other petrologic facies to have significant permeability. For convenience, several other rock facies were lumped together as "low permeability" rock types. These three groupings of petrologic facies were the basis of permeability-porosity correlations for the field. It was observed that the chaotic and grainstone facies were restricted to stratigraphic horizons in the South Cowden Unit, so the stratigraphic markers were utilized in building the correlation equations.

For the 20 wells with core porosity data, conventional porosity-permeability regression equations were derived for the three rock groups. These equations were used directly to compute permeability for the cored wells. Permeability correlations for the grainstone and low-permeability rock groups were also developed on a field-wide basis for use with the remaining wells.

Evaluation of waterflood performance, reservoir simulation, and core study demonstrated that a single correlation equation for the chaotic facies would not adequately describe the permeability distribution of the field. Correlation equations for nine wells show more than an order of magnitude difference in permeability between the best and worst wells in the field (Fig. 17). Permeability measurements from plugs cut specifically within the gray or tan portions of the core show that permeability is restricted to the tan subfacies (Fig. 18). In addition to porosity and the abundance of tan relative to gray rock in the chaotic facies, dolomite crystal size and abundance of anhydrite cement also influence permeability. Work is in progress to use well performance data to improve the permeability prediction.

Preparatory/Conceptual Reservoir Simulation Studies for Reservoir Characterization

Equation-of State (EOS) Fluid Characterization

A recombined separator fluid sample was taken from the South Cowden reservoir. The recombined reservoir fluid composition is given in Table III. A Peng-Robinson equation with a sixteen component fluid description was chosen to initially characterize the South Cowden reservoir fluid. Five pseudo components were chosen to characterize the C_{7+} fraction of the oil. The EOS was tuned to match laboratory fluid analysis data with volume translation used to improve the fluid density match.

The experimental data set used for tuning the EOS included differential liberation data; pure component injection gas density, viscosity, and Z-factor data; and vapor-liquid equilibrium data from CO_2/reservoir oil swelling tests at 15, 30, 41, and 68 mole percent injection gas. A satisfactory match to all experimental data was obtained with the sixteen component fluid description given in Table IV. The quality of the match obtained between experimental and EOS predicted fluid properties is shown graphically in Figures 19 to 29.

The pressure vs. composition diagram for this fluid description is shown in Figure 30. Emphasis was placed on matching vapor and liquid phase properties and compositions in both the low pressure (634 psia flash of 41 mol% injection gas) and high pressure (2514 psia flash of 68 mol% injection gas) regions of the pressure-composition space investigated by the experimental data. A comparison of experimental vs. EOS predicted phase relative volumes, compositions, and intensive properties is presented in Table V and Figures 31 and 32. Measured saturation pressures were matched to within about 150 psi at the lower CO_2 concentrations.

After the sixteen component EOS had been tuned to obtain a satisfactory match of the experimental data, the number of components was reduced using a stepwise regression procedure to generate a more tractable fluid characterization for use in compositional reservoir simulation. A comparable match with the experimental data (maximum deviation in any property vs. 16-component characterization about 7%) was obtained after reduction to an eight component fluid description. The eight component EOS fluid characterization is shown in Table VI.

Compositional Simulation of Laboratory Slim Tube Displacements

The final EOS fluid characterizations (both the sixteen component and eight component fluid descriptions) were incorporated into a one-dimensional compositional simulation model to predict laboratory slim tube displacement behavior. A satisfactory match of laboratory slim tube oil recovery and gas-oil ratio behavior was obtained using both fluid characterizations (Figures 33 and 34). Further prediction runs were made to characterize the recovery efficiency vs pressure for CO_2 with the South Cowden crude (Fig. 35). The minimum miscibility pressure (MMP, defined as the pressure where oil recovery efficiency exceeds 90% OOIP at 1.2 PV injection) was determined to be approximately 1200 psia. This compares favorably with slim tube displacement experiments conducted in the early 1980's using South Cowden stock tank oil which indicated MMP to be approximately 1140 psig. Current reservoir pressure at the South Cowden Unit is above 2000 psi and substantially above the required MMP.

Identification of Important Reservoir Description Parameters

Key geologic reservoir description parameters controlling performance of a CO_2 flood in the South Cowden reservoir were identified based on preliminary simulation runs and geologic description of cores from the project area. A program of conceptual simulation runs was outlined to investigate the sensitivity of CO_2 flood performance to these key parameters: (1) the number of layers, permeability heterogeneity, and Kv/Kh ratio within the chaotic facies in the primary reservoir interval (Zone E); (2) the degree of vertical communication between Zone E and adjacent Zones D and F; (3) the placement of the horizontal injection well within the vertical reservoir section; (4) the impact of completion efficiency of the horizontal injection well, including mechanical skin, Kv/Kh ratio, permeability of the completion layer, and the effective contributing length of lateral section.

Results of these early simulations were used to help focus the geological reservoir characterization efforts toward those parameters which had the greatest impact on project performance. Most significantly, this work prompted additional examination of geologic controls on permeability distribution and effective Kv/Kh within the main chaotic reservoir facies.

Modeling Approach

Both fully compositional and modified black-oil mixing parameter simulation are used in the South Cowden study. Compositional simulators have the advantage of allowing a more rigorous and realistic treatment of phase behavior and mass transfer effects during the multi-contact CO_2/oil displacement process. However, they require much more computational effort and computing time particularly when simulating complex phase behavior. These factors can be major limitations when very large, full-field simulations are needed to model effects of heterogeneity and sweep efficiency in cases where irregular well patterns or horizontal wells are used, such as in the South Cowden project.

Modified black-oil, mixing parameter simulators have the advantage of requiring less computational effort and computing time because they assume a simplified first-contact miscible phase behavior, adjusted or modified with empirical mixing rules to describe effective transport and displacement characteristics. However, these empirical parameters must be correctly specified either by history-matching of field performance or by matching the CO_2 flood process performance of a compositional simulator. This approach allows practical simulation of large problems and/or incorporation of more heterogeneity into the reservoir model. In many cases, correct representation of reservoir heterogeneity has a larger impact on CO_2 flood performance than does the degree of rigor used in representing the phase behavior.

A five-spot pattern model with reservoir properties representative of the "sweet spot" in the proposed South Cowden project area was set up and run on both the compositional and mixing parameter simulators. Empirical parameters in the mixing parameter model were adjusted until its performance matched that obtained with the fully compositional simulator using a 16-component EOS to represent fluid phase behavior. Parallel runs were made on the two simulators during reservoir characterization sensitivity studies to assess the response to changes in layering, Kv/Kh, grid size, etc. and ensure that comparable performance was obtained with the mixing parameter model under a wide range of displacement conditions.

The mixing parameter model initially produced optimistic results compared with the compositional simulations. Several factors were identified as contributing to this difference. First, unadjusted CO_2 injectivity was higher in the mixing parameter model. Apparently compositional phase behavior effects resulted in a lower CO_2-rich phase mobility. Code changes were made in the mixing parameter simulator to allow adjustments to the solvent phase relative permeability to better match both experimental data and compositional model injectivity. Second, additional code changes were made to incorporate CO_2 solubility in the aqueous phase in the mixing parameter simulator. Correctly modeling this effect reduced incremental CO_2 flood oil recovery by 8-10%, depending on WAG strategy, and resulted in increased gas production during the later project life. Third, the compositional model produced a significant fraction (7-8%) of the total incremental hydrocarbons as NGL's in the separator gas stream. This compositional behavior could not be simulated with the simplified phase behavior used in the mixing parameter model. Oil recovery predictions from the mixing parameter simulations were adjusted to account for this effect. Finally, areal and vertical sweep efficiency comparisons showed the displacement to be slightly less efficient in the compositional simulations than in the mixing parameter simulations. The value of the mixing parameter (omega) was adjusted until the mixing parameter model performance matched the compositional model results. With these adjustments to the empirical parameters in the mixing parameter model, comparable performance forecasts were obtained from the two simulation models over a wide range of conditions of heterogeneity and WAG strategy.

Grid Size Sensitivity Studies

Grid size sensitivity studies were conducted to aid in selecting a full-field model grid. The five-spot pattern model was used for these studies. The sensitivity of waterflood response to areal grid size and numerical dispersion is shown in Figure 36. Too coarse an areal grid resulted in early water breakthrough and lower waterflood oil recovery. The compositional and mixing parameter models produced comparable primary depletion and waterflood forecasts. Cumulative oil production vs. time for the two models is shown in Figure 37. Areal sweep and displacement characteristics were also similar, as shown by the saturation profiles at the end of waterflood (Fig. 38).

Incremental CO_2 flood oil recovery was also affected by numerical effects due to areal grid size. Figure 39 shows the effect of areal model grid cell size on incremental oil recovery for both the compositional and mixing parameter models. The two models converge to the same value as grid cell size is reduced and numerical effects are eliminated. Incremental recovery appears to be more sensitive to grid size effects in the mixing parameter model than in the compositional model in this case.

Grid size sensitivities were also run to look at the impact of vertical grid resolution, or number of layers, on CO_2 flood performance. Figures 40 and 41 show some sensitivity of performance to layer thickness (number of layers). Incremental oil recovery was reduced about 5% as layer thickness was reduced from 20 feet to 2 feet (from 3 layers to 30 layers used to represent the main reservoir interval). Gas production response was more sensitive to vertical grid resolution; gas production increase approximately 12% as layer thickness was decreased. These results show that using too great a layer thickness in the model will tend to underestimate gravity override effects.

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

A first version model was created in STRATAMODEL using the stratigraphic framework defined by the structure maps for the Grayburg top and the G, E, D, C, B and A markers. Computed porosity curves and normalized gamma ray logs from the well logs were uploaded and used to interpolate 3-D porosity and gamma ray attributes. This process has revealed additional wells with anomalous porosity values which need to be reviewed. Interpolation algorithms and vertical resolution of the model are being assessed. The initial assumption of conformable depositional geometry within the reservoir sequence appears to be reasonable, because no great unconformities have been revealed in the porosity or gamma ray log attributes. The E interval appears to have some internal layering.

ADVANCED TECHNOLOGY DEFINITION

The project SOW contains seven primary subtasks in the Advanced Technology Definition task. Progress on these seven subtasks is discussed on the following pages in the SOW subtask order.

Special Laboratory Studies

Magnetic Resonance Image (MRI) Screening of Core Plugs

Magnetic Resonance images were made for 52 core plugs from South Cowden Unit Well 8-19. These images provided porosity distributions inside each plug which helped in the selection of the best plugs for flooding studies.

Magnetic Resonance Imaging (MRI) measures the fluids in the pores, not the rock, thus the images show the location and amount of fluids inside the rock. The images consist of 256 x 256 pixels with the intensity of each pixel proportional to the amount of fluid at that location in the rock. MRI images can be used to measure saturation, however, these core plugs were 100% saturated with water, so the signal intensity was proportional to porosity.

Two imaging orientations were measured, the first, along the length of the core, produced rectangular images while the second, across the core, produced circular images. Using two orientations helps do a better job of detecting porosity heterogeneities because these are often more visible in one orientation than another. Multiple slices, approximately 4mm thick, provided 3-D information about the location of heterogeneities. Most of these cores were easy to image and gave sharp pictures.

The images of these 52 plugs showed many dramatic variations in porosity within small distances, mm's. The sharp demarcations between significantly different porosity regions suggested mixed lithology in these plugs. The MRI images appeared to correlate well with surface texture, again suggesting lithological changes. Those plugs with significant porosity variations also probably have significant permeability variations.

Most of the plugs contained mm to cm sized heterogeneities but a few were of nearly uniform porosity. The plugs chosen for flooding experiments were either uniform or mostly uniform with a continuous uniform porosity path from one end to the other.

An example of one plug which was not chosen for experimentation is shown in Figure 42. This core plug had a significant porosity variation along the major axis. The porosity distribution along the long axis is displayed rather than the image because the images do not reproduce well with the standard office copy machines. Standard core measurements gave a porosity of 20.6% for this plug. The image, and the porosity distribution in the Figure, showed that one end of the plug was about 8% porosity while the other was as high as 45%

porosity. If a flooding experiment had been performed on this plug, without the MRI information, it would have been assumed that the porosity was 20.6%, but the response would have represented that from a low porosity plug and a high porosity plug flooded in series. Although it would be very interesting to image the flooding in the more heterogeneous core plugs, the interpretation of the data would be very complex. In fact, data from a core with unknown porosity heterogeneities could be worse than no data, since it could provide misleading information.

CO_2 Miscible WAG Trapped Gas Experiments

Introduction

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 measure these parameters to provide data for use in making predictions of WAG performance in the South Cowden Reservoir, an associated coreflood experiments was conducted. South Cowden live oil, synthetic live brines, along with Magnetic Resonance Imaging (MRI) screened native state carbonate cores from the subject reservoir were used in conducting the flood, which was performed at South Cowden reservoir conditions of 98° F and 1800 psig.

Materials

The live oil used in the study was prepared from filtered South Cowden stock tank oil. The filtered oil was enriched with C5's and C6's and recombined with a C4- gas to a bubble point of approximately 625 psia at 98° F.

Fifteen core plugs, from SCU Well 6-23, were selected from the group of 76 native state core plugs which were subjected to Magnetic Resonance Imaging. These plugs were further screened by measuring their permeability to brine. Based upon both MRI and permeability screening, two plugs were selected for subsequent use in a CO_2 Miscible WAG Trapped Gas Experiment. The selected cores were used in forming a composite core.

Synthetic brines were used in this study. The composition of the brine was patterned after an analysis of SCU formation water dated February, 1995. The total dissolved solids content of the brine was approximately 72,000 ppm. The synthetic brine used during the initial water injection step was saturated with methane at 98° F and 1800 psig so that no significant gas would be taken from that which was soluble in the live oil. The synthetic brine used during the second water injection step was saturated with CO_2 at 98° F and 1800 psig so that no significant CO_2 would be taken from that which was otherwise trapped in the core.

Apparatus

Schematics of the apparatus used in this experimental program are provided in Figures 43 and 44. In Figure 43, the oven containing the core holder along with some of the more important external pieces of equipment are shown. One of the more notable of the external pieces of equipment is the Boyle's Law apparatus which was used in determining the trapped gas saturation.

The oven in Figure 44 was largely devoted to containment of the pressurized supply fluids which included brine, stock tank oil (STO), live oil, and CO_2. One vessel permitted CO_2 to be bubbled into live oil and thus allowed a gradient live oil/CO_2 front to be passed through the core to simulate a miscible front.

Procedures

As mentioned above, the core used in this experiment had been brine flooded as part of the selection process. Restoration was completed by first flooding the core with STO to drive them down to an irreducible water saturation (S_{wi}). This was followed by live oil floods to displace the dead oil. The live oil floods were conducted on consecutive days. After displacing the STO, the composite core was shut-in overnight and allowed to equilibrate with the brine in the core. Additional live oil was injected on the following day to better insure that the GOR of the live oil was similar to that in the live oil supply vessel. This second live oil flood essentially completed the restoration process.

Data was obtained, during the latter stages of the second live oil flood, from which the oil permeability (k_o) at S_{wi} could be calculated. This permeability measurement served as the reference permeability in the subsequent relative permeability calculations (k_{rw} at S_{orw}, k_{rco2} at S_{orm}, and k_{rw} at S_{gtrap}).

For reasons mentioned above, methane saturated brine, at 98° F and 1800 psig, was injected during the initial water injection step. In this coreflood, approximately 0.8 pore volumes of brine were injected. While oil production had not absolutely stopped, it was approaching levels that were difficult to measure. A plot of the injectivity of this phase of the study (to be presented in the Results and Discussion section) indicates that the permeability had essentially lined-out after less than 0.5 pore volumes of injection.

The CO_2 flood step was somewhat more involved than simply injecting dry CO_2 after the initial brine flood. To initiate the CO_2 flood step, the lines were first flushed up to the core inlet (at the top of the core) with live reservoir fluid. CO_2 was then injected into the bottom of a mixing accumulator (containing live oil) 10 cc/hr. The CO_2 mixes and dissolves in the live oil, swelling it. Effluent from the accumulator, after passing through a filter, is the injectant for the core flood. Initially the core will see reservoir fluid. The displacing phase "gradates" to CO_2 as the CO_2 content of the mixing cylinder increases. In this manner the CO_2 coreflood is stabilized. This process creates a CO_2/oil viscosity-graded zone that should help reduce viscous fingering.

CO_2 saturated brine was injected during the post-CO_2 waterflood. The measured viscosity of this fluid was determined to be 0.847 cp. The total water volume input during this step of the WAG injection process is not to exceed 1.2 pore volumes.

The post WAG analyses was comprised of numerous steps. The primary focus of these steps was to determine the trapped gas saturation in the composite core which existed after the second brine flood.

Subsequent to the second brine flood, the core was shut-in and allowed to cool to room temperature while maintaining a constant confining pressure. The core was then de-pressurized through a multi-stage separator. Produced gas and liquid (dead oil and brine) volumes were recorded. The void volume created in the core during the de-pressurization process was then measured using a Boyle's Law of Expansion process. The determined void volume should be larger than the actual trapped gas volume due to the loss of some liquid saturation during blow down and to shrinkage of the liquid saturation during blow down.

After de-pressurization (or blow down) of the composite core, the remaining water in the core was removed via vacuum distillation at elevated temperature (core still under confining pressure). The water was captured in a cold trap and gravimetrically measured. An adjustment was made to convert water volume produced to brine volume. Any residual oil produced during this step was to be volumetrically estimated. At the end of the vacuum distillation step, the core was again allowed to cool to room temperature and the void volume was again measured via Boyle's Law of Expansion.

While the core was still mounted in the core holder and under confining pressure, the residual oil and salt were removed from the core via pumping toluene and methanol through the core until the effluent was colorless (ion analysis can be used if necessary to monitor salt removal by the methanol). The core was then vacuum dried to remove the toluene and methanol. After drying, the total pore volume of the core was measured via Boyle's Law of Expansion.

After the vacuum distillation and toluene/methanol cleaning procedures were completed, the cores were subjected to.Dean Stark cleaning and/or analysis. Grain, bulk, and pore volumes along with grain density and N_2 permeabilities were subsequently measured via routine core analysis methods.

Calculation of CO2 Trapped Gas Saturation

Before discussing the results, it is considered worthwhile to point-out how the CO_2 trapped gas volume, used in obtaining the CO_2 trapped gas saturation, is determined using data obtained from conducting the above procedures. (The trapped gas should be envisioned to be a gas which is rich in CO_2 and not pure CO_2.) In verbal form, the equation to calculate the trapped gas volume should read as follows:

Volume of CO_2-Rich Phase Trapped at 98° F and 1800 psig =

Void Volume from Boyle's Law Measurement at Lab Conditions -

Volume of Water Expelled during Blow Down Adjusted for Shrinkage -

Shrinkage of Water Left in Core after Blow Down -

Shrinkage of Residual Oil Volume Left after Blow Down.

In symbolic form, the equation could be written as:

$$V_{CO2} = V_{BL} - (V_{WBD} * FVF_W) - (V_{WR} * FVF_W - V_{WR}) - (V_{OR} * FVF_O - V_{OR}). \quad (1)$$

Results and Discussion

A summary of this South Cowden CO_2 Miscible WAG Trapped Gas Experiment is provided in Table VII. In addition to the trapped gas data, key data of interest include k_{rw} at S_{orw} (see above comments in Brine Flood 1 subsection), k_{rco2} at S_{orm}, S_{orm}, and k_{rw} at S_{gtrap}. The influence of the trapped gas is evident when the water relative permeabilities at the end of the two waterfloods are compared. The relative permeability of water at S_{gtrap} (0.118) is shown to be approximately 27 percent lower than the relative permeability of water at S_{orw} (0.162).

High, low, and average estimates (where the average is simply the average of the high and low determinations) of the trapped gas saturation are provided in Table VII. The following error analysis data were applied to equation (1) in determining the high and low estimates of the trapped gas saturation:

Boyle's Law after Blowdown (cc)	± 0.1
Calculated Volume Water Collected (cc)	± 0.25

Brine FVF w/CO2 at 98° F and 1800 psig	± 0.0065
Total Water Collected during Vacuum Dist. (cc)	± 0.5
Estimated Sorm (cc)	± 0.026
Residual Oil FVF w/CO2 prior to Blow Down (rb/stb)	± 0.05
Total Pore Volume of Individual Core Plugs (%)	± 1.0

The ease with which fluids could be injected into the South Cowden composite core, from the beginning of the live oil flood to the end of the second brine flood, is indicated in the Injectivity (cc/hr/psi) versus Pore Volumes Throughput plot which is presented in Figure 45. As indicated by the relative permeability data in Table VII, the injectivity of brine after the CO_2 flood is somewhat less that prior to the CO_2 flood.

Conduct Laboratory Corefloods To Identify Potential Foaming Surfactants For CO_2 Mobility Control

The primary objective of this subtask was aimed at identifying specific foaming surfactants which may be needed for CO_2 mobility control in the South Cowden project through a five part laboratory program.This subtask began with determination of surfactant adsorption in the South Cowden Unit Field cores. Figure 46 shows a schematic diagram of the adsorption setup. A Waters Model 410 refractomer was used to monitor the surfactant concentration in the effluent. About one liter of synthetic Free Water Knock Out (FWKO) brine (TDS=7.84%) was circulated through the core while monitoring the effluents on the refractomer. This was done to obtain an equilibrated brine avoiding changes in refractive index due to dissolution of core material during the surfactant adsorption test. An overnight circulation at 60 cc/hr was sufficient to achieve equilibration of the brine. This brine was used to prepare the surfactant solutions used in adsorption test. The "Calibration Sample Loop" shown in Figure 46 was filled with about 9 ml aliquot of the surfactant solution at a given concentration. This solution was then pushed through the sample side of the refractometer while recording its response. This process was repeated for at least four surfactant concentrations. A plot of the refractometer's response vs. known surfactant concentration was used to calculate the surfactant concentration in core effluents during the adsorption test.

Seven adsorption experiments in cleaned South Cowden Unit field cores were performed. Cores were selected for use after evaluation by MRI to avoid severe fractures, obstructions, etc. before they were coated (epoxy) and equipped with end plates. Each core was then placed in a core holder and pressurized to a confining pressure of 2000 psi. An aliquot of the equilibrated brine was used to prepare a 0.5 wt % surfactant solution. About 0.3 to 1.2 PV of 0.5% surfactant solution was injected into the core at a flow rate of 9 cc/hr (~6-12 ft/day) using the "Injection Sample Loop" shown in Figure 46. The core was then flushed with several pore volumes (PV) of equilibrated brine while monitoring the effluent concentration on the refractometer. Figure 47 shows a plot of surfactant concentration in the core effluent for Chaser™ CD-1045 in a clean South Cowden Unit field core at 98° F. Each tick mark on the x axis represents one pore volume of effluent. In this experiment 60.0 mg of surfactant was injected into the core, recovering 18.4 mg of surfactant in 5 PV of the effluent which translates to 2127 lbs/acre-ft surfactant adsorption. While refractive index data indicate a slow surfactant desorption even after 10 PV of core effluent, surfactant adsorption was calculated at 5 and 10 PV of effluent. A value of 1593 lbs/acre-ft was calculated for 10 PV of the effluent.

Figure 48 shows a plot of adsorption versus rock porosity for Chaser™ CD-1045, Chaser™ CD-1050, Rhodapex CD-128 and Foamer NES-25 calculated from seven tests performed in South Cowden cores. While the data points at 15.1% porosity (Foamer NES-25) might be anomalies, the adsorption data for the 5- and 10-PV effluent appear to have a maximum around 20% porosity. It is evident from this Figure that the adsorption values measured at 10-PV core effluent are smaller than those measured at 5-PV. Figure 48 also indicates that surfactant adsorption has a higher dependency on core porosity (surface area) than surfactant type.

Screening Studies to Identify Suitable Gelled Polymers for Profile Modification

Introduction

Gels produced by an *in situ* cross-linking reaction of water-soluble polymers are used to block water intrusion into producing wells[1-2]. These are also effective in injection profile modification, i.e., redirecting the injection fluid flow to a less permeable zone containing oil by placing gels in high permeable streaks or fractures near the injection wells[2-6].

A gel is a three-dimensional polymer network, produced by cross-linking of polymer chains, swollen with a solvent. It typically possesses mechanical properties similar to those of natural rubber, with high deformability and nearly complete recoverability. Gels used in oil recovery applications are hydrogels, i.e., the polymer networks that possess the ability to swell in water and retain a significant fraction of water within their structures, but these will not dissolve in water. These gels typically consist of about 0.5-3% of cross linked water-soluble polymers that hold 99.5-97% water in an equilibrium state. Exposure of the gel to forces such as temperature, pressure, pH, etc. that might alter the nature or the degree of cross linking can disrupt this equilibrium which usually results in shrinkage with expulsion of water from the gel[7]. This phenomenon is called syneresis and is often observed in many oilfield gel systems. For instance, when polyacrylamide gel is exposed to hard brine at elevated temperatures for an extended period of time, the gel shrinks to small particles which are brittle. Thus, there is no single polymer gel system for every reservoir application.

The purpose of this subtask is, therefore, to identify one or more suitable polymer systems for possible use at the SCU for fluid diversion as well as for water shut-off applications. The gels should be stable and effective under anticipated CO_2 injection conditions.

Experimental

Polymer Solution: The polymers used for this screening study are emulsion as well as solid materials. The emulsion polymer, OFXC®1163, was received at 30% active concentration from American Cyanamid. Approximately 6100 ppm polymer stock solution was prepared by inverting 6.58 g of emulsion in 300 ml produced brine containing 0.276 ml of Activator 478® (American Cyanamid) in a blender (Osterizer) running at high speed for 30 seconds. The polymer stock solution was allowed to stand at room temperature until all air bubbles disappeared. The test solutions were prepared using the homogeneous stock solution.

The polymer stock solution using solid material was prepared by adding a measured quantity of a solid polymer to the vortex which was produced by stirring a measured amount of solvent with a magnetic stirrer bar. The stirring was continued until the polymer particles were completely dissolved which usually varied from 8 to 24 hours.

The aqueous cross-linker solutions were also diluted to a convenient concentration level with distilled water before using in the preparation of test solutions. The test solutions were prepared by adding an aliquot for the desired concentration of cross-linker to the measured aliquot of polymer stock solution. Any necessary makeups for obtaining desired concentrations of polymer and cross-linker were done with produced brine. The test solutions were shaken well before placing them into the oven for aging at reservoir temperature.

Gel Evaluation: About 20 ml aliquot of gelling mixture are placed in a series of glass ampules (OD=2.2 cm, Length= 22.5 cm) and sealed. The ampules are then placed vertically in a metal container and aged in the oven at the desired temperature. For the first 12 to 24 hours of aging the ampules are checked frequently for gelation by placing the ampule horizontally behind a shield. Then the gelling mixture is allowed to flow to equilibrium and its tongue length (TL) is measured. This tongue length usually decreases with aging times. The percent gel strength (%GS) is then calculated from Equation 1 and is determined as a function of time.

$$\%GS = (22.5 - TL)x100/22.5 \qquad (1)$$

Percent gel strength as defined by Equation 1 is based on an ampule length of 22.5 cm.

A high pressure apparatus was designed and fabricated for evaluation of gel stability under

2000 psi of CO_2 pressure to simulate field use in a CO_2 pilot. The schematic of the apparatus is shown in Figure 49. Two high pressure stainless steel vessels were equipped with a pressure gauge and a rupture disk safety relief valve. These vessels were connected to an LDC Bio pump and a booster pump to pressurize the vessels. A programmable ISCO syringe pump was used to depressurize the test vessels at a uniform rate. The pressurized vessels were housed in a thermostatted chamber. A series of preformed full strength gels in glass ampules was placed vertically inside the vessels. The vessels contained just enough produced brine to hold the samples without floating in it. The ampules were opened and about 10 ml produced brine was added on top of each gel sample. Then the lids were tightly screwed and the vessels were pressurized at 2000 psi with CO_2. The vessels with contents were aged for three weeks at the reservoir temperature of 98° F. Then, the ISCO syringe pump was programmed to release the pressure at a rate to depressurize the system over the period of six days to avoid creating a strong pressure turbulence which might shatter the gels.

Results and Discussion

The Phillips files on the past polymer work at the SCU were reviewed first. The previous laboratory work was conducted using simulated brines. Two different simulated brine compositions were found. Total dissolved solid (TDS) contents in these two formulations differed by 2 wt%. Thus, it was decided to analyze SCU produced water. Since this formation water is high in H_2S content, it was felt that simulated brine might have to be used for polymer/gel screening studies. Three samples of produced water collected from different points in the unit were analyzed, (see Table VIII). These samples were not significantly different from each other and the TDS was about 7.8 wt%. An aerated sample of produced water did not differ with respect to Na^+, K^+, Ca^{++}, Mg^{++}, and Cl^- ions from the original sample. However, sulfate ions in the aerated sample were found to be about 1000 ppm higher than that of the original sample. The aerated sample was again analyzed twice for sulfate and the sulfate content was found to be about 3700 ppm both times which was within 100 ppm compared to one of the original samples. The previous large discrepancy was perhaps due to an instrumental error. The aerated produced brine did not have any significant odor. Therefore, polymer gel work was conducted in aerated SCU produced water instead of a simulated brine.

Table IX lists the polymers and crosslinkers that were studied. Two commercially available acrylamide polymers and three cross-linkers were studied. The first system studied was with a high molecular weight ($10\text{-}15 \times 10^6$) anionic (5-7 mole%) polyacrylamide (in emulsion), OFXC ®1163 (American Cyanamid) and a low toxicity zirconium cross-linker, Zirtech® LA110 from Benchmark R&T Inc.. Since the pH of a carbon dioxide flood is in the range of 3.9 to 4.2 and the gelled polymer will be also used for diverting the fluid of a planned carbon dioxide flood in SCU the system was studied in SCU produced water at an adjusted pH of 4.2. The pH of aerated sample of SCU produced water measured about 6.5. The results of the studies are given in Tables X and XI. The progress of gelation was monitored by measuring the tongue length[8] of the gelling mixture. The tongue length develops when the gelling solution begins to form a crosslinked three dimensional structure strong enough to hold fluids within its structure. The tongue length decreases as the gel strength increases. Thus, the tongue length gives a measure of gel quality. As can be seen from Tables X and XI the gelation rate is slightly faster at an adjusted pH of 4.2 in all crosslinker concentrations studied. It is also noticeable that the gelation rate decreases with increasing crosslinker concentration and developed significantly weaker gel beyond 750 ppm zirconium concentration. This observation is consistent with previous studies in other brines. Since the system of OFXC®1163 and Zirtech® LA110 were recently successfully field-tested at the North Burbank Unit (NBU) in Oklahoma and at the C. B. Long Unit in Texas, the gels produced with 500 ppm Zr in SCU water are compared with those produced in NBU or in C. B. Long produced waters as shown in Table XII. Although the gelation rate in SCU produced water was slightly slower compared to the other two produced waters, the system developed acceptable gels at SCU reservoir conditions.

The second system consisted of a low molecular weight ($3\text{-}5 \times 10^5$) solid anionic (5 or < 5 mole%) polyacrylamide, Alcoflood® 254S (Allied Colloids) and Zirtech® LA110. This system was studied at the adjusted pH of 4.2 only. The results are shown in Tables XIII and XIV. This system produced acceptable strong bulk gels at much higher concentrations of 20,000-30,000 ppm polymer and 500 ppm Zr level. However, the gelation rate of this system is significantly slower making the system suitable for near well bulk gel treatment. The gels produced by both polymer systems are found stable after prolonged aging for more than 200 days.

The polymer/gel screening studies described above were conducted at 120° F temperature. However, the reservoir temperature of the SCU it is said to vary from 98° to 120° F, therefore, the bulk gel tests using both polymers with zirconium crosslinker were repeated in pH adjusted (3.9-4.2) SCU produced water at 98° F. In addition to these screening tests both polymers were also tested with widely used MARCIT® chrome acetate as well as another low toxicity titanium crosslinking system in SCU produced water (pH adjusted) at both temperatures. All these screening test results are summarized in Figure 50.

Both polymers with Zr crosslinker developed acceptable gels at 98° F. There is no significant difference in the gelation rate for high molecular weight polymer (OFXC® 1163) at both temperatures. However, in the case of low molecular weight polymer (Alcoflood® 254S), the gelation rate is significantly slower at 98° F and the system utilizes higher polymer and crosslinker concentrations. The OFXC® 1163 with chromium acetate crosslinking system developed gels at a much slower rate than the zirconium system. For example, the system containing 5000 ppm OFXC® 1163 and 250 ppm Cr developed only 68% gel strength at 120 ° F or 0% gel strength at 98° F after 3.12 hr aging. These compare to the percent gel strengths of 81% and 80% at 120° F and 98° F, respectively developed by Zr containing system at the same concentration levels after only 2.5 hours of aging. However, although chromium acetate resulted in strong gels at 120° F the gels at both temperatures are loosening up by expelling water from the gels after 42 days of aging whereas no separated water in zirconium gels after 206 days of aging at the similar conditions. On the other hand, the low molecular weight polymer (Alcoflood® 254S) with chromium system developed gels at a faster but more uniform rate than that with zirconium system and the gels are stable with no sign of separated water after 115 days of aging.

The third low toxicity titanium crosslinker with OFXC® 1163 developed gels at a slower rate with no sign of gel forming characteristics until after 6 hours and measurable gel strength after 23 hours of aging at 98° F. The system developed about 85% gel strength after 5 days of aging and after 57 days of aging the gel strength is increased to about 95% indicating a long term gel stability. This system utilizes low concentrations of polymer and crosslinker making the system economically attractive.

The next phase of bulk gel work involved gel stability tests under 2000 psi CO_2 pressure to simulate field use in a CO_2 pilot. Two systems, the low toxicity OFXC® 1163 with Zirtech® LA110 system and Alcoflood® 254S with MARCIT® chrome acetate system were tested. The testing gels were prepared first using 1% OFXC® 1163 with 250-1500 ppm Zr in pH unadjusted SCU produced water and 2% Alcoflood® 254S with 250-1500 ppm Cr in pH adjusted (4.2) produced water. It is interesting to note that Alcoflood® 254S even at 4% concentration level did not produce gels with Cr in pH unadjusted produced water. The preformed gels were then exposed to 2000 psi pressure of CO_2 (See Experimental) and aged at 98° F for three weeks. The results are given in Table XV. The gels of both systems are stable with no sign of deterioration or water phase separation. However, since the MARCIT® chrome acetate gels are produced in pH adjusted water, these gels may not withstand the CO_2 pressure for a very long time due to the possibility of over cross-linking which will cause syneresis.

Conclusions

1) The system of high molecular weight (10-15x10^6) anionic (5-7 mole%) polyacrylamide, OFXC®1163 and low toxicity zirconium cross-linker, Zirtech® LA110 makes strong gels in SCU produced water and gels are stable at the reservoir temperature under anticipated CO_2 injection conditions.

2) The low molecular weight (3-5x10^5) anionic (5 or < 5 mole%) polyacrylamide, Alcoflood® 254S and low toxicity zirconium cross-linker, Zirtech® LA110 system also makes strong and stable gels. This system is attractive particularly for its significantly slow gelation rate. However, the system utilizes much higher polymer and cross-linker concentrations making it a somewhat expensive system.

3) The high molecular weight polymer, OFXC®1163 with another low toxicity titanium

cross-linker, RIX:98 develops acceptable gels at much slower rate than the OFXC®1163/Zirconium system. It is also important to note that this system utilizes lower cross-linker concentration.

4) Although MARCIT® chrome acetate with Alcoflood® 254S produces strong gels at the desired rate, the system utilizes much higher concentrations of polymer and cross-linker. The system also produces gels only at a lower pH so that the gels may not withstand CO_2 pressure for a very long time.

Advanced Geostatistical Studies

Geostatistical Studies

Two types of geostatistical methods were initially proposed for generating the 3-D porosity model of the South Cowden Unit, i.e. a deterministic method and a stochastic data integration method. The former utilizes the spatial information in form of the variogram model of well porosity (hard data or more accurate data) and ordinary 3-D kriging to generate the least bias estimate of the variation in the interwell porosity. The latter data integration method uses in addition the statistical distribution of the seismic attribute (soft data or less accurate data) that correlates with the well porosity distribution as prior conditional distribution information to generate a new posterior distribution at each common midpoint (CMP) location in the seismic data. Consequently, when hard and soft correlated data information are available, which was not the case in this instance due to the unique impedance structure of this reservoir unit, this method provides increased resolution on the scale of the seismic data CMP spacing. In addition, this method is capable of generating N equally probable models of the spatial continuity of a reservoir which allows for assessment of risk and the measurement of the degree of uncertainty in the porosity model from these multiple model realizations. The remainder of the section will outline the analysis on the acoustic impedance (AI) structure and 3-D seismic data from this reservoir unit that prevented the use of geostatistical data integration techniques, and the results of the ordinary 3-D kriging of the reservoir porosity for three different vertical grid cell sizes (i.e., 2 ft, 5 ft and 10 ft) and horizontal grid cell size of 100 ft x 100 ft .

Analysis of Seismic-Reservoir Acoustic Impedance Correlations

The reservoir unit modeled for its seismic response and correlation with porosity ranged from the base of the Cowden Sand to the top of the D zone with the interval between the top of the E and top of the D zone the principle unit of investigation for the CO_2 flood. While 132 wells were used in the 3-D kriging of the reservoir porosity, only 18 wells had both sonic and density information needed to generate the synthetic seismogram responses for this interval of the reservoir. These logs covered the Emmons, Moss and Phillips units and were located in Sections 7, 8, 17 and 18 of the proposed CO_2 flood area. Modeling of the seismic response was typically performed over a depth range of 700 feet to 800 feet with the average overburden and underburden thickness around the reservoir unit varying between 400 feet and 500 feet and 100 feet and 300 feet, respectively. A 30 Hz zero phase shift Ricker wavelet provided a good match to the 3-D seismic data at the well locations and was used in the generation of all the synthetic seismograms.

Figure 51A and 51B show two processed versions of an east-west seismic time section (line 80 from trace 26 to 122; CMP spacing 110 feet) out of the 3-D dataset which goes across the southern end of the Emmons Unit and crosses near the Emmons well 215 (trace 88). At trace 74, which is located in the middle of the section, the base of the Cowden Sand marker is defined approximately by a seismic trough and occurs at a two way time of 754 msec. The relative amplitude section, which is nearly a true amplitude section and used in reservoir characterization, is quite noisy down at the reservoir interval as indicated by the 3 x 3 trace mixed weighted section also shown in the figure and used for structural interpretation.

Figures 52 through 56 show the results of the porosity-acoustic impedance correlation at well log (0.5 foot log spacing, series A figures) and seismic (15 feet for 40,000 AI units to 21 feet at 60,000 AI units; series B figures) resolutions and the correlation between the time integrated acoustic impedance structure at seismic resolution and the synthetic seismogram traces (series C figures) for a random section of five of these wells. Here, the time integrated impedance and porosity logs and synthetic traces are shown in depth. In time, they equate to a constant time sample rate of 2 msec. It is pointed out here that the reflectivity series is the ratio of two adjacent impedances and the reflectivity increases as the impedance contrast increases between two intervals.

The C series figures show the depths for the three vertical line markers in the B and C series figures that correlate with (1) the base of the Cowden Sand (shallowest marker), (2) the top of the E zone and (3) the top of the D zone (deepest marker). It is seen for this interval, and from these porosity-impedance data in general, that the porosity is inversely related to the acoustic impedance with the porosity increasing as the impedance decreases. From the C series figures, it is found that the seismic trough does not always correlate with the base of the Cowden Sand and the E zone interval (marked by the tops of the E and D units) can fall within this seismic trough and almost into the next seismic peak. Moreover, these data indicate that both variations in overburden impedances above the base of the Cowden Sand and the rate of decrease in the impedance in the transition zone between the base of the Cowden Sand and the top of the E unit have a pronounced affect on generation of the reflection amplitude characteristics associated with this interval. The variations observed in reflection signal over these markers are caused by complex constructive and destructive interference reflection patterns that are not solely associated with either the base of the Cowden Sand or the top of the E zone. No definite seismic markers, e.g. magnitudes of trough amplitude, peak amplitude or trough-peak time isochron values, appear to exist that can be uniquely correlated with porosity changes within the interval. Consequently, stochastic data integration techniques was not considered in this instance a viable option in generating the 3-D porosity model for this reservoir unit. The low signal-to-noise ratio of the relative amplitude seismic sections at the reservoir unit also precluded the use of seismic inversion in this case which can yield the impedance variation and subsequently, the porosity variation in the reservoir unit on the 15 foot to 20 foot resolution scale.

Ordinary 3-D Kriging for the Porosity Modeling

Well log porosity information from the base of the Cowden Sand to slightly below the top of the D zone (dependent of available log data) were obtained from 132 wells and used in the generation of the 3-D porosity model. While the analysis was performed on three zones, i.e. base of the Cowden Sand to top of F zone, top of F zone to top of E zone and the top of E zone to the top of D zone, only the results of the E zone interval which has the highest porosity and EOR potential is reported here. The basemap of the well locations used in the study are shown in Figure 57 along the highlighted model area which has an east-west distance of 18,000 feet and a north-south distance of 12,000 feet. Each block in the figure is 2000 feet x 2000 feet.

The kriging for a 3-D porosity modeling was performed using a horizontal grid cell size of 100 feet x 100 feet and three vertical grid cell sizes, i.e. 2 ft, 5 ft and 10 ft. There were 120 grid cells in the north-south direction and 180 cells along the east-west direction. The spatial information on the variability of the porosity both vertically (z axis) and horizontally (x-y axis) were obtained from vertical and horizontal variograms generated on the well porosity in the E zone from 132 wells. Variogram modeling was also performed on the top of the E and D layers for these wells and provided the stratigraphic trend surface boundaries for the 3-D kriging model.

The variogram which is defined as one-half of the variance of the argument, $\{V(x,y)-V(x+n\Delta x,y+m\Delta y)\}$, measures the spatial disimilarity or correlation range of a variable, V over n and m lag distances. Its value is zero when $V(x,y)$ and $V(x+n\Delta x,y+m\Delta y)$ are equal. Its value is a maximum, reaching a sill as the lag distances between variables increases, when this difference argument approaches the variance of the data. At this distance, specified by a range, the values of the variable are no longer considered to be spatially correlated. Thus, the variogram model with its range and sill provides a means of capturing spatial variability and range of heterogeneity of a variable away from a well.

Figures 58A and 58B show the vertical and horizontal variograms and their model fits calculated for the E zone. The well log porosity data were sampled ever 0.5 feet and the vertical variogram was obtained using a 2 foot lag distance and 35 lag steps. It is seen that a sill is reached at approximately 20 feet indicating that the well log porosity values are no longer correlated past this distance. It also suggests that the vertical grid cell size needs to be kept less than this distance to accurately capture the changes in the vertical heterogeneity. While this variogram was calculated from all the wells, additional studies on different square mile sections over the field yielded similar ranges. The variogram model on core porosity are shown in Figure 58C for six wells and indicate a cyclic behavior in the core porosity values for some of the wells and a smaller correlation range of less than 10 feet. Consequently, vertical grid cell sizes were kept at or less than 10 feet for the 3-D porosity modeling.

The horizontal variogram and variogram model used in the generation of the 3-D porosity model are shown in Figure 58B. Here the lag distance was taken at 1980 foot intervals with well data used over +/- 990 foot range. In this instance, the scale of the horizontal heterogeneity is limited by the distance between wells and the correlation range is approximately less than that 6000 foot.

Figure 59A, 59B and 59C shows for cell 90 in the north-south direction the 3-D kriged north-south cross-section of the E zone porosity variation for the vertical cell sizes of 2 ft, 5 ft and 10 ft. The porosity scale ranges from 2.5% to 25% with the horizontal relief varying by almost 250 feet over the 12,000 foot model distance. It is seen that the vertical heterogeneity is fairly accurately captured with the 10 foot cell size with the 5 foot cell size still perserving most of the fine scale heterogeneity seen at the 2 foot cell size. Figure 60 shows two more north-south cross-sections of the porosity variation at cell 60 and 120 in the east-west direction while Figure 61 shows two east-west cross sections of the porosity zone for cells 40 and 80 in the north-south direction for the 5 foot vertical cell size. Surface views of the porosity variation in the E zone are also shown at depths of 25 feet and 50 feet below the top of the E unit in Figure 62. These cross-sections and surface views indicate that the highest porosity potential in the E zone exists east of cell 40 in the east-west direction and north of cell 30 in the north-south direction. In summary, the variograms and variability in the 3-D porosity model suggest that the vertical cell size in a flow simulator may need to be around 10 feet to perserve the vertical heterogeneity seen in the porosity data for the E zone.

Reservoir Simulation for Project Design and Performance Forecasting

Full-field Simulation Model for the South Cowden Unit

A three-dimensional simulation model of the South Cowden Unit was built using a 54 x 54 areal grid with six layers to describe the CO_2 flood target interval covering Zones C, D, E, and F described in the reservoir characterization work. This simulation model grid contains 17,500 active cells and covers a 7.5 square mile area incorporating approximately 170 wells. Greater areal grid definition was used in the "sweet spot" of the reservoir identified as the most attractive potential project area within the Unit. The vertical grid was refined within the main reservoir interval (Zone E). This provided the ability to incorporate the details of reservoir heterogeneity within the E Zone, to allow simulation of vertical movement of fluids due to gravity segregation, to evaluate alternative placement of horizontal injection wells within the reservoir section, and to make sensitivity runs to evaluate variations in permeability stratification and effective Kv/Kh ratio.

PVT data for the model were derived from the reservoir fluid characterization work. Relative permeability and rock property data were based on special core analysis (SCAL) data from five wells in the South Cowden field; these included conventional, oil-base native state, and sponge cores. Data were available for 21 water-oil relative permeability tests (both steady-state and unsteady-state tests were run); 32 water-oil relative permeability endpoint tests; 15 gas-oil relative permeability tests; and 8 CO_2/oil coreflood tests. Four of the CO_2/oil corefloods were special tests designed to measure CO_2 trapped gas saturation, residual oil to CO_2 displacement, and endpoint CO_2 and water relative permeabilities in a WAG process. Magnetic resonance imaging was used to screen many of the core plugs prior to testing to ensure that no "hidden" internal heterogeneities were present in the plugs to add scatter to the data. These data were all normalized and correlated by geologic lithofacies and by reservoir zone. This resulted in three major rock types being identified for use in field-wide simulation modeling work.

Individual layer structure, isopach, and porosity maps were digitized and incorporated into the reservoir simulation model. Porosity vs. permeability relationships, capillary pressure and initial water saturation distribution functions, and relative permeability data were input based on the distribution of the three major rock types identified in the reservoir characterization work. Initial water saturations varied from approximately 10% PV in the best reservoir quality rock in the project area to almost 30% PV in the poor reservoir quality areas on the western margin of the Unit. The original oil-in-place for the Unit was calculated to be 117 MMSTB.

Vertical permeability measurements were available on a foot-by-foot basis for whole core analyses from three wells in the project area. The measured vertical permeabilities were generally greater than the measured horizontal permeabilities in the E Zone in these three wells. Initial Kv/Kh ratios in the model were estimated by using harmonic averages for the vertical permeability and using geometric means for the areal permeability. This resulted in an average Kv/Kh ratio of 0.21 for the E Zone. In addition, the vertical transmissibility was further restricted across several layer boundaries which had been identified in the geologic studies as depositional sequence boundaries extending over much of the field area.

History Match of Primary and Waterflood Performance

An interactive, "predictive" history matching approach was used to match field performance. In this approach, wells are not "forced" to produce or inject at their historical oil production or water injection rates. Rather, actual well constraints (operational, facility, and regulatory) are applied to each well along with the well's completion and stimulation history, and the wells are allowed to produce or inject as much fluid as these constraints and the model reservoir description will allow. For example, constraints applied to the SCU producing wells include the individual well completion and stimulation history, artificial lift constraints governing liquid lifting capacity and producing bottomhole pressure, and any regulatory allowable limits which were in effect during early field life. Injection well constraints included the completion and stimulation history, and the wellhead injection pressure vs. time.

During history matching, the model reservoir description was adjusted until a satisfactory prediction of both primary depletion and waterflood performance was obtained with the model. Prior to major history match iterations, several sensitivity cases were often run in which key parameters (e.g. porosity, permeability, Kv/Kh, completion efficiency, etc.) were varied in order to demonstrate the magnitude of influence of each parameter at this point in the matching process. This approach allowed the entire reservoir characterization team to be involved in making decisions as to which model parameters were best candidates to adjust to obtain the desired performance and still keep the model consistent with all reservoir characterization data. Successful prediction of oil production rate vs. time was the primary criterion chosen to determine that a satisfactory history match had been obtained. The key parameters which had to be adjusted to match historical performance were the aquifer influx during early producing life, the effective Kv/Kh ratio, and the permeability vs. porosity transforms used to estimate the three-dimensional permeability distribution.

The resulting final prediction of oil recovery vs. time for the historical production period is shown in Figure 63. Note that at least some of the wells were constrained by regulatory allowable limits until about 1970; after that time all wells were producing at capacity. The corresponding prediction of water injection rate vs. time is shown in Figure 64. The predicted water injection matches actual performance very well during the period 1965-1976 when the reservoir is filling up and being repressured. After the Unit reaches peak oil production rates in the mid-1970's, measured water injection exceeds the simulator predictions by about 25 percent. A review of injection profile surveys run in the mid-1980's and available on all but two injectors shows an average of about 30% out-of-zone injection. Microfracturing tests run in the two reservoir characterization wells drilled in 1994 indicated that fractures in this reservoir tend to initiate in the lower part of the section and grow downward toward a high permeability grainstone interval below the oil-water contact. Further evidence of substantial out-of-zone injection comes from a single-zone production test of the grainstone interval in the SCU 8-19 well in 1992. The grainstone interval had sufficient pressure to flow 100% water to the surface.

Over the past two years, wellhead injection pressures have been decreased and in November of 1994, a number of injectors with poor injection profiles were shut-in. Over this period (1993-1995), the actual water injection rate has approached the predicted rate and the two curves match very well after the shut-in of several problem wells in November, 1994 (Figure 64). Figure 65 compares simulator predictions of watercut performance vs. measured field data. The model predictions show a reasonably good overall match with historical field performance, however during the period from 1989-1994, the predicted watercuts were 90-92% compared with observed watercuts of 94-95%+. This difference is substantial, representing about 4000-5000 barrels more water being produced from the field than is predicted by the simulation model history match. Much of this excess water was being produced from one well (SCU 6-13). This well had been hydraulically fractured and was equipped with an electrical submersible pump, producing 4000+ barrels of fluid per day at a 95+% watercut. After the SCU 6-13 well was shut-in in late 1994, along with several other high watercut producing wells and offsetting injection wells, the field watercut and the model predictions agree very well (Figure 65). This indicates that much of the injected water during this period was probably being ineffectively cycled through the reservoir.

The final model predictions also matched individual zone RFT pressures measured in recent project area infill wells (SCU 8-19 and 6-23). This pressure match confirmed that the overall material balance in the project area was satisfied, and gave additional confidence that effective Kv/Kh ratios between reservoir zones was modeled adequately. Besides matching zone-by-zone RFT pressures, the production rate and water cut performance of these two wells, plus two additional infill wells drilled in the past few years were matched. This provided additional confidence that the current saturation and pressure distribution in the model should approximate actual reservoir conditions at the start of CO_2 flood operations.

Design of Horizontal Well Scheme and the Final Project Development Plan

Horizontal Well Placement and Pattern Configuration for the Project

A number of preliminary full-field simulation runs were made to evaluate CO_2 flood performance under various configurations of horizontal and vertical wells. Initial runs were made to evaluate the impact of horizontal well length, placement, and completion efficiency on CO_2 flood performance. Several alternative project development options were simulated. These were evaluated for oil recovery efficiency, areal and vertical sweep efficiency and CO_2 utilization efficiency.

Several prediction runs were made for each of the more promising cases to evaluate the effect of uncertainties in the geologic reservoir description and well completion efficiency on project performance. A primary focus in this work was on the placement and completion strategy for horizontal CO_2 injection wells under various reservoir description cases.

CO_2 Injection Strategy for the Project

Several simulation runs were made to evaluate CO_2 process performance under various alternative pattern configurations and project development scenarios. CO_2 injection rate and wellhead injection pressure requirements were calculated and provided to the facilities design team for use in sizing and design of the CO_2 distribution system and injection well facilities. Compositional simulation runs were made to provide initial estimates of produced gas rates under various development scenarios. CO_2 purchase volumes and recycle volumes were forecast for several different CO_2 injection and recycle strategies.

Compositional simulation runs were also made to provide estimates of produced gas composition and potential NGL yield vs. time. Figure 66 shows typical composition vs. time profiles computed for a five-spot pattern model. This analysis showed that 7-8% of the total incremental hydrocarbons produced by the CO_2 flood process would be produced as NGL's in the separator gas stream. This volume is not sufficient to warrant significant investment in gas processing facilities for the CO_2 project.

Development Plan

The objective of the development plan is to systematically drill wells, convert wells, construct and modify facilities in order to flood the Unit with CO_2 in such a manner to maximize the net present value as well as mitigate project risk.

The initial objective of the project is to drill the RC-3 well between the surface locations of the two horizontal wells. This well will be cored and data collected to finalize selection of the location and stratigraphic placement of the horizontal WAG injection wells. After the horizontal injection wells are tested for water and CO_2 injectivity, producers will be reactivated or drilled in the most advantageous locations.

The second objective is to start injection of CO_2 along the lease line. Wells will be reactivated and drilled to accomplish this objective. Specific locations to be drilled or wells to be converted have been selected for the plan; however, as the wells are drilled and more information is available to upgrade the reservoir model, the location of the wells may be adjusted. Figure 67 is a development plan map for South Cowden.

Well locations have been selected in the plan to best utilize existing wellbores. Risk of costly well repairs has been reduced by testing casing integrity of wells that have been premised to be utilized in the flood. All but one of the WAG injection wells will be new, reducing the risk of the CO_2 being injected out of zone because of previously induced fractures.

The WAG injection facilities will be constructed during the first year to allow injection of water for test and for early start of CO_2 injection. The existing water injection system will also be replaced in the first year due to inadequate pressure capability for the increased injection pressures required.

The existing production facilities will continue to be utilized to a large extent, with upgrading for recent regulatory requirements as well as preparing for the production of CO_2. The facilities will be upgraded with CO_2 analyzers the first year and vessel replacement in later years.

A vendor will be employed to compress the produced CO_2 for re-injection. The vendor will provide the facilities including compression (as needed) and dehydration. The vendor will construct for a lump sum the facilities and operate the compression installed. As additional or reduced compression is required, the vendor will modify the horsepower installed and adjust charges appropriately.

Details and timing of the well work and facility work are detailed in Tables XVI and XVII.

Forecast Generation

Forecasts for the CO_2 project were generated using the three-dimensional simulation model of the SCU and the development plan discussed above. Critical laboratory data on CO_2/oil phase behavior, minimum miscibility pressure, and oil recovery efficiency were matched and incorporated into the model. The model was then used to evaluate various alternative CO_2 project development scenarios, including the optimum use of horizontal CO_2 injection wells. The most attractive project development alternative incorporates both horizontal and vertical CO_2 injection wells to conform to the reservoir geology and maximize sweep efficiency and oil recovery. This configuration is presented as the AFE Base Case development plan.

In addition to the Base Case performance forecast, the model was used to generate Low Case P(10) and High Case P(90) forecast, by involving the entire team to identify the most significant areas of uncertainty in modeling. The major factors contributing to uncertainty in the forecast and related model parameters which were varied to obtain the P(10) and P(90) production profiles are:

1) RESERVOIR HETEROGENEITIES (permeability variation in the main pay zone, the presence/absence of correlative high permeability "thief zones" for CO_2, and the effective Kv/Kh ratio);

2) INJECTIVITY AND HORIZONTAL WELL COMPLETION EFFICIENCY (CO_2 injectivity, injection well skin, and horizontal well completion efficiency);

3) CO_2 PROCESS EFFICIENCY AND OIL RECOVERY (remaining "target" oil available for CO_2 and the amount of oil bypassed by viscous fingering).

The simulation accounts for combinations of all of these factors to generate P(90) and P(10) forecasts with the oil rate forecast, CO_2 purchase volume, and gas recycling requirements all handled consistently. Figure 68 displays the P(10), P(50), and P(90) forecasts. In addition, the model was used to generate forecasts for several discrete option cases including variations of leaseline cooperative injection with Fina and replacement of the horizontal CO_2 injection wells with vertical injectors.

Design of Upgrades and/or Additions to Production, Water Injection, CO_2 Injection, Compression, Water Disposal, Automation, Electrical and Cathodic Protection Facilities

A team of engineers and construction personnel were assembled to document the premises to be used in field implementation of the project. The premises generated by this team are given in Appendix I. These premises are consistent with the project development plan and the costs used to forecast project economics.

Investment Cost Forecast, Operating Cost Forecast and Generation of the Authority for Expenditure (AFE)

Capital Investment

Capital investments are based on an agreed set of detailed premises. These premises were developed by a team including drilling, production and reservoir engineers, geologists, and safety, construction and operations personnel in order to adequately cover all aspects of the project and ensure that the risk of changes due to oversight would be at a minimum.

Cost estimates for the new wells and the conversions are based on the approved premises for drilling and completion. Cost estimates are substantiated utilizing actual costs from recent well work. Four additional wells above and beyond the plan are to cover the unexpected loss of wells due to casing failure. The estimates include tubing and down hole pumping equipment even though much of this equipment is already available in the South Cowden Unit. Table XVIII contains a capital investment summary.

CO_2 Purchase

The terms of the CO_2 purchase agreement are under negotiation and considered to be confidential. Values used in the economics are consistent with the expected final agreement.

Operating Expense

Current unit operating expenses are \$0.75 MM/yr for the 38 producing and 15 injection wells in the unit. The operating expenses are projected to increase to \$1.1 MM/yr after the project is implemented and will increase to 1.3 MM/yr by the year 1999. The number of unit wells will increase to 47 producers and 31 injectors.

Over and above the general operating expenses, new expenses for CO_2 purchase, CO_2 re-injection, and fuel for compression will occur. A graph showing the magnitude of these expenses is shown in Figure 69. Table XIX summarizes all operating costs. The total cost to operate the unit will vary from $3 MM to $4 MM per year, depending on the amount of CO_2 purchased and CO_2 re-injected. Average unescalated lifting costs will average $5-6/BOE during the life of the project. Early years of the project may exceed $10/BOE as large CO_2 purchases are made prior to the expected oil response.

Manpower and Automation

The unit will continue to be operated by one pumper, however, the project will require that an automation technician spend 34% of his time to maintain the alarms, H_2S/CO_2 monitors, pump off controllers and WAG injection controls.

All 34 pumping wells in the project area of the unit will be equipped with pump off controllers. Only 2 of the wells on the unit currently have pump off controllers. In addition, the WAG injection system will be automated to control injection rates, protect against overpressuring of wells and collect volume and pressure data for both water and CO_2 injection.

Automation within the battery will not be upgraded except for the addition of H_2S/CO_2 monitors and alarms.

Safety and Health

Part of the South Cowden Unit lies within a residential housing development. The subdivision in the southern part of Section 17 is about 80% developed and the development is moving northward toward the area of the unit that will be CO_2 flooded (see Figure 70); however, only a few of the lots in the northern area have been sold. As part of the project, the surface rights of the north half of Section 17 will be purchased, to establish a buffer zone between the area of the unit which will be flooded and the existing residential area.

H_2S dispersion models have been run to determine the risk of H_2S reaching the residential area. The worst case scenario was determined to be the blowout of an injection well. Modeling indicates this worst case would not create an immediate hazard to the surrounding residents.

To further mitigate the exposure of H_2S to the public, the land purchased will be fenced and public access limited. The flare at the main tank battery will be moved farther away from the development. H_2S monitors will be installed around the Tract 6 battery as well as along the fence line bordering the residential area.

Economic Evaluation and Risk Analysis

The economic evaluation is based on the development schedule, capital investment, production forecast and operating cost given in Tables XVI through XIX and Figure 68. In addition to the base case economics calculated using the above referenced information, economics were also calculated using risk assessed input data. The P(10) value is defined as the value having only a 10% chance of being smaller; P(50) has a 50% chance of being smaller; P(90) has a 90% chance of being smaller. See page 40 for the major factors contributing to uncertainty in the forecast and related model parameters which were varied to obtain the P(10) and P(90) production profiles.

A force field evaluation was performed outlining the major reasons for and against the South Cowden CO_2 project and is displayed in Table XX.

A full risk analysis was performed on four variables considered the most critical to the South Cowden CO_2 project: oil price, reserves/recovery efficiency, capital investment and expenses. Figure 71 identifies the variables (excluding oil price and reserves) and their P(10), P(50) and P(90) values.

The reserve forecast limits are shown in Figure 68. The P(10) case represents a 22% reduction in reserves and the P(90) case a 20% increase. These forecasts reflect variations in reservoir heterogeneities, injectivity and horizontal well comletion efficiency, and CO_2 process efficiency/oil recovery.

The capital investment was increased in the P(10) case to cover the necessity of replacing the two horizontal wells with vertical wells and redrilling an additional four wells for a total of eight replacement wells. The facility costs were also increased by 15%. A total capital increase of 30% resulted from these assumptions. The capital was reduced in the P(90) case by not drilling four premised replacement wells and reducing facility costs by 15%. A total capital reduction of 15% resulted from these premises.

Total expenses were increased in the P(10) case by 15% including the field operating costs, CO_2 purchases, and recycle expenses. The field operating expenses and recycle expenses were reduced by 15% and CO_2 purchases were reduced by 5% in the P(90) case.

Project Authorization for Expenditure (AFE)

An AFE was prepared and submitted to Phillips management and the unit working interest owners. The AFE has been approved and field initiation of the project will begin in late October.

REFERENCES

1. M. A. Gruenenfelder, A. Zaitoun, S. A. Ali, and T. M. Linser, *SPE/DOE Paper 27770* [SPE/DOE 9th Symposium on Improved Oil Recovery Proceedings, vol. 1, Tulsa, Oklahoma, USA], 387 (1994).

2. G. P. Southwell and S. M. Posey, *SPE/DOE Paper 27779* [SPE/DOE 9th Symposium on Improved Oil Recovery Proceedings, vol. 1, Tulsa, Oklahoma, USA], 513 (1994).

3. P. D. Moffitt, and D. R. Zornes, *SPE Paper 24933* [67th Annual SPE Technical Conference and Exhibition, Washington, DC, USA], 813 (1992).

4. D. R. Zornes, H. Q. Long, and A. J. Cornelius, *SPE Paper 14113* [International Meeting on Petroleum Engineering, Beijing, China], 311 (1986).

5. T. E. Doll and M. T. Hanson, *SPE Paper 15162* [Rocky Mountain Regional Meeting of the SPE, Billings, MT, USA], 281 (1986).

6. J. C. Mack, and J. Warren, *J. Pet. Tech.*, 36, 1145 (1984).

7. P. M. DiGiacomo and C. M. Schram, *SPE Paper 11787*, [International Symposium on Oilfield and Geothermal Chemistry, Denver, CO, USA], 165 (1983).

8. A. Moradi-Araghi, G. Bjornson, and P. H. Doe, *SPE Paper 18500* [SPE International Symposium on Oilfield Chemistry, Houston, Texas, USA], 367 (1989).

LIST OF FIGURES

FIGURES

FIGURE 1

Phillips #6-23 South Cowden Ut.

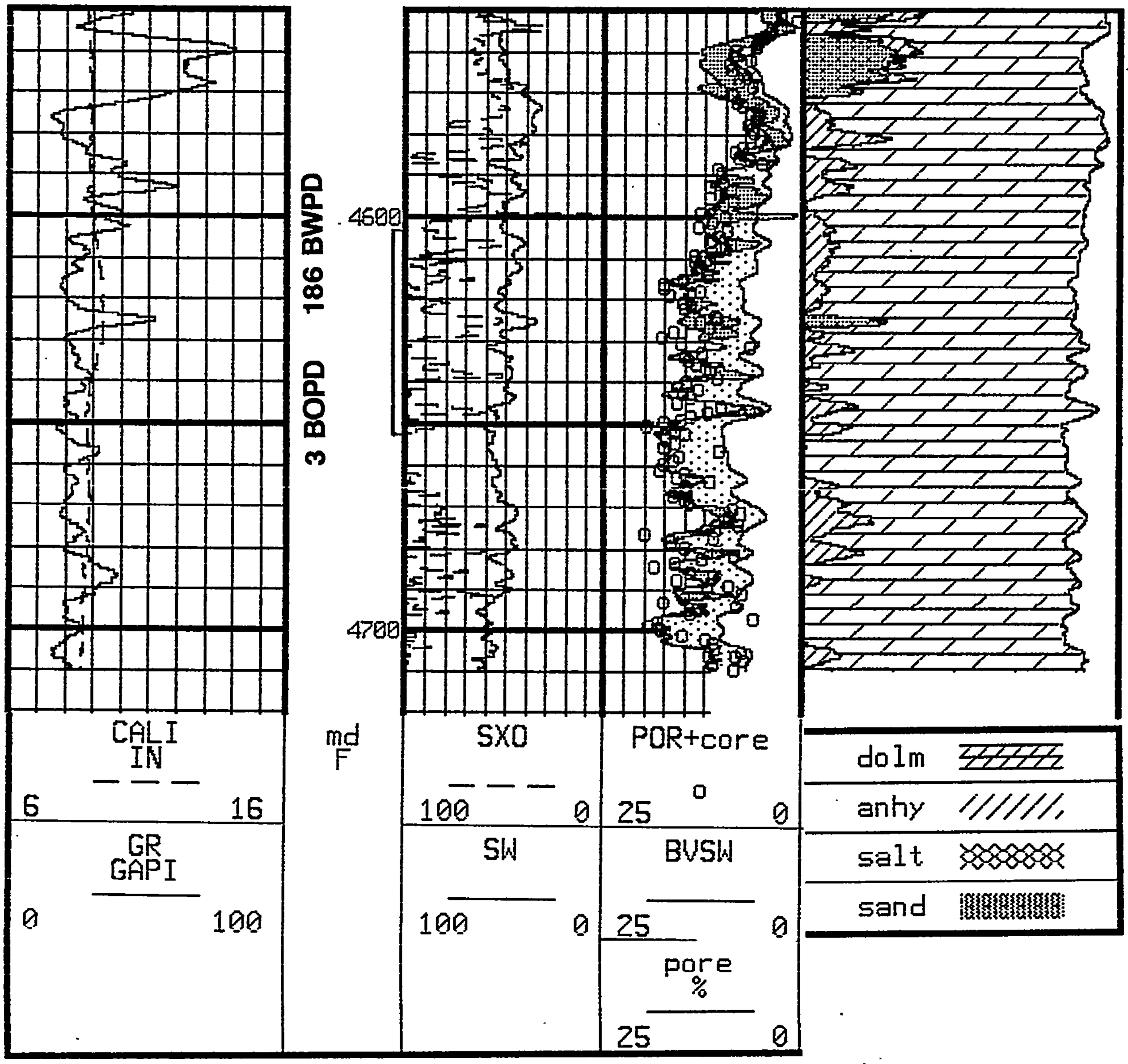


FIGURE 2

Phillips #6-21 South Cowden Ut.

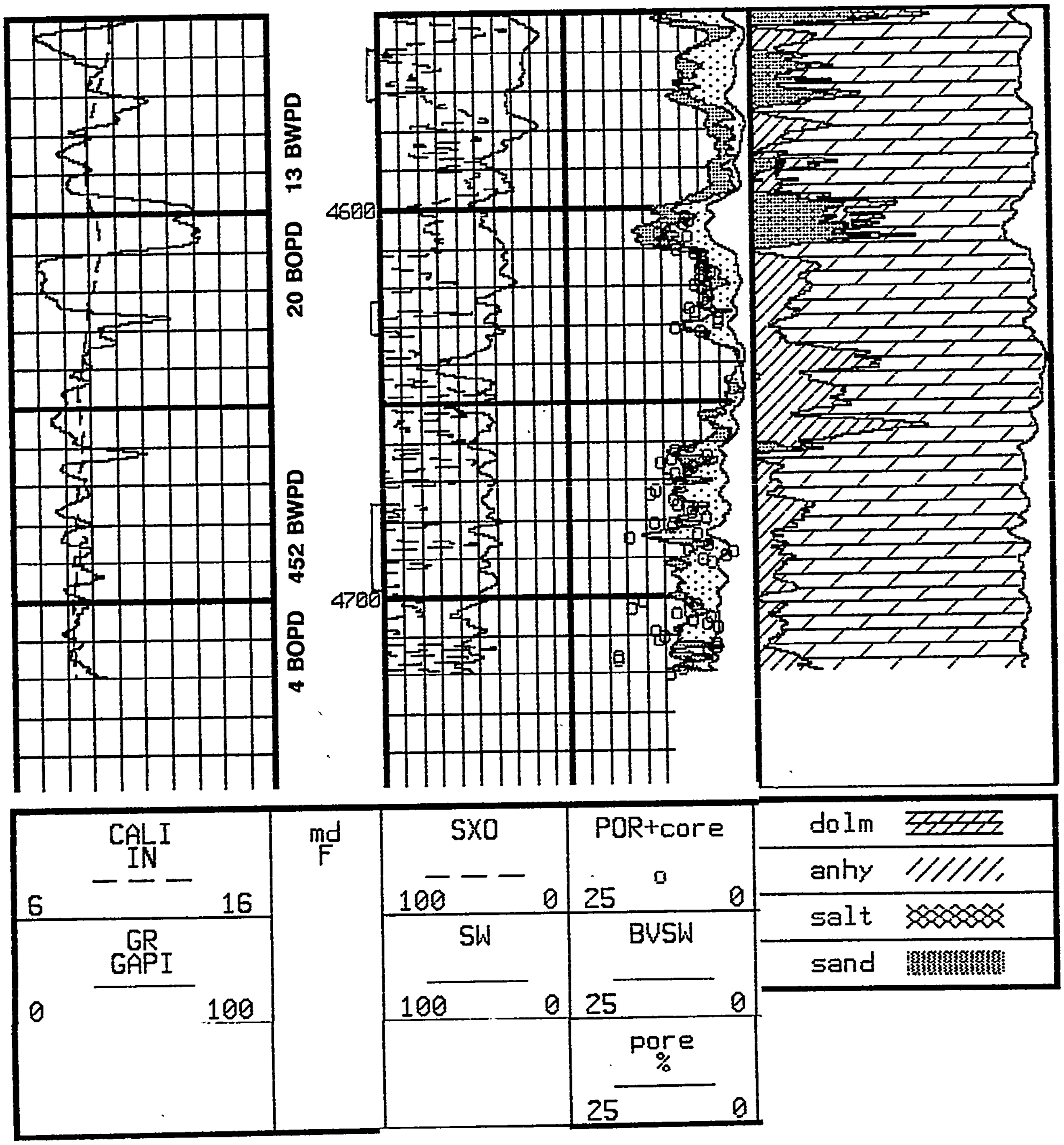


FIGURE 3

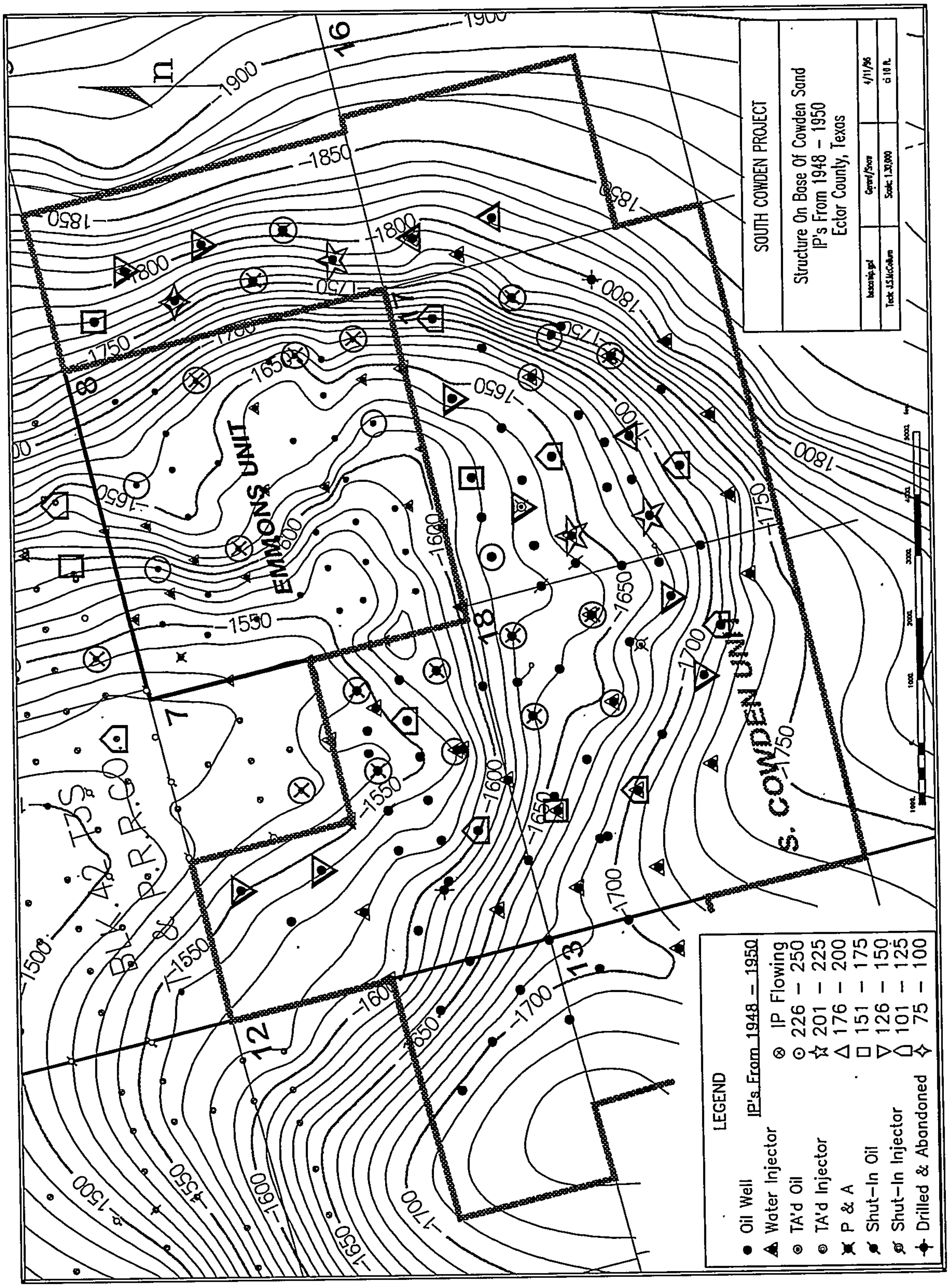

SOUTH COWDEN PROJECT
Structure On Base Of Cowden Sand
IP's From 1948 – 1950
Ector County, Texas
EMMONS UNIT
S. COWDEN UNIT
LEGEND
IP's From 1948 – 1950
Oil Well
Water Injector
TA'd Oil
TA'd Injector
P & A
Shut–In Oil
Shut–In Injector
Drilled & Abandoned
IP Flowing
226 – 250
201 – 225
176 – 200
151 – 175
126 – 150
101 – 125
75 – 100

FIGURE 4

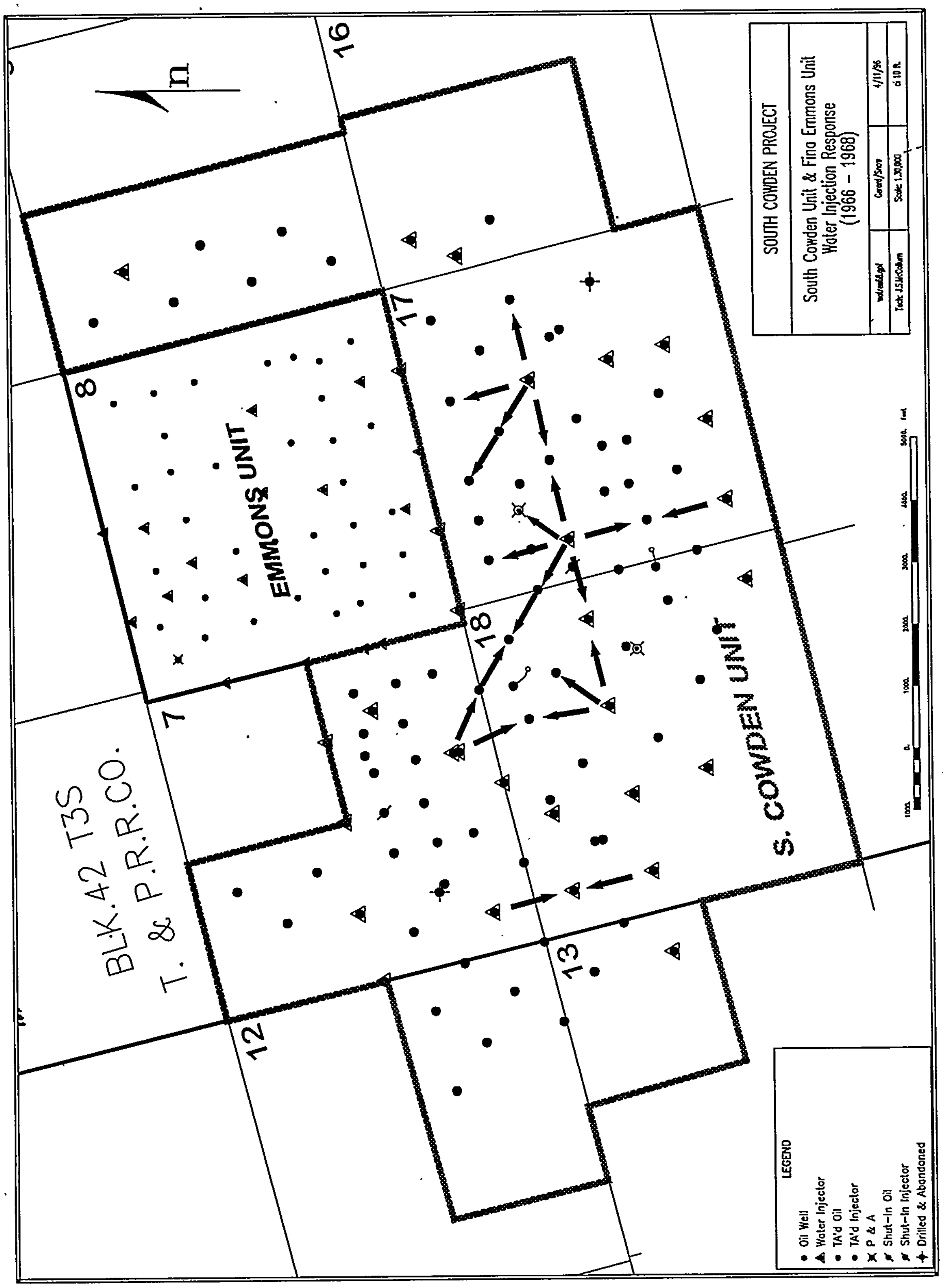

SOUTH COWDEN PROJECT
South Cowden Unit & Fina Emmons Unit
Water Injection Response
(1966 - 1968)
EMMONS UNIT
S. COWDEN UNIT
BLK. 42 T3S
T. & P.R.R.CO.
16
17
8
18
7
13
12
LEGEND
Oil Well
Water Injector
TA'd Oil
TA'd Injector
P & A
Shut-In Oil
Shut-In Injector
Drilled & Abandoned

FIGURE 5

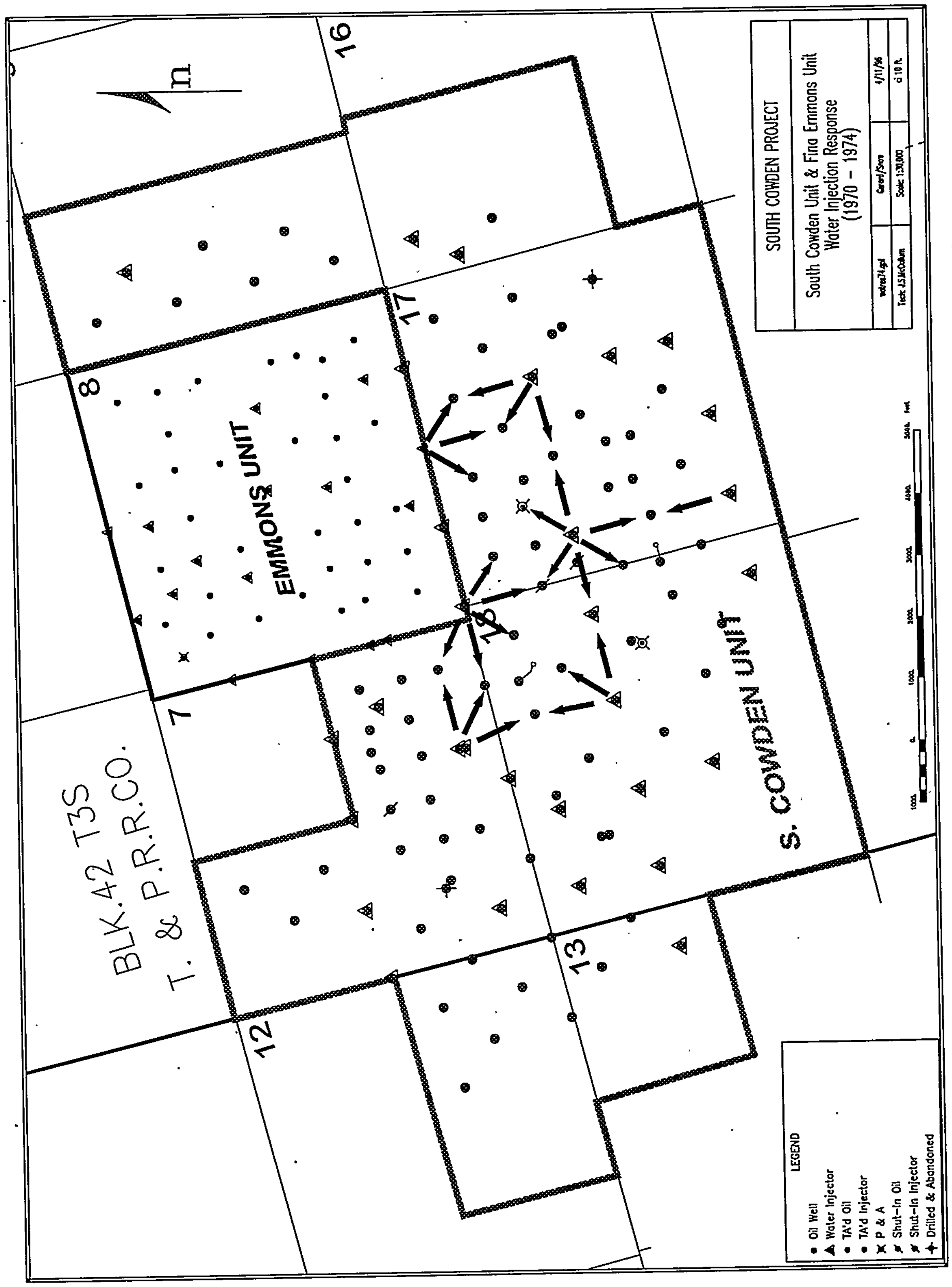

SOUTH COWDEN PROJECT
South Cowden Unit & Fina Emmons Unit
Water Injection Response
(1970 - 1974)
EMMONS UNIT
S. COWDEN UNIT
BLK.42 T3S
T. & P.R.R.CO.
LEGEND
Oil Well
Water Injector
TA'd Oil
TA'd Injector
P & A
Shut-In Oil
Shut-In Injector
Drilled & Abandoned

FIGURE 6

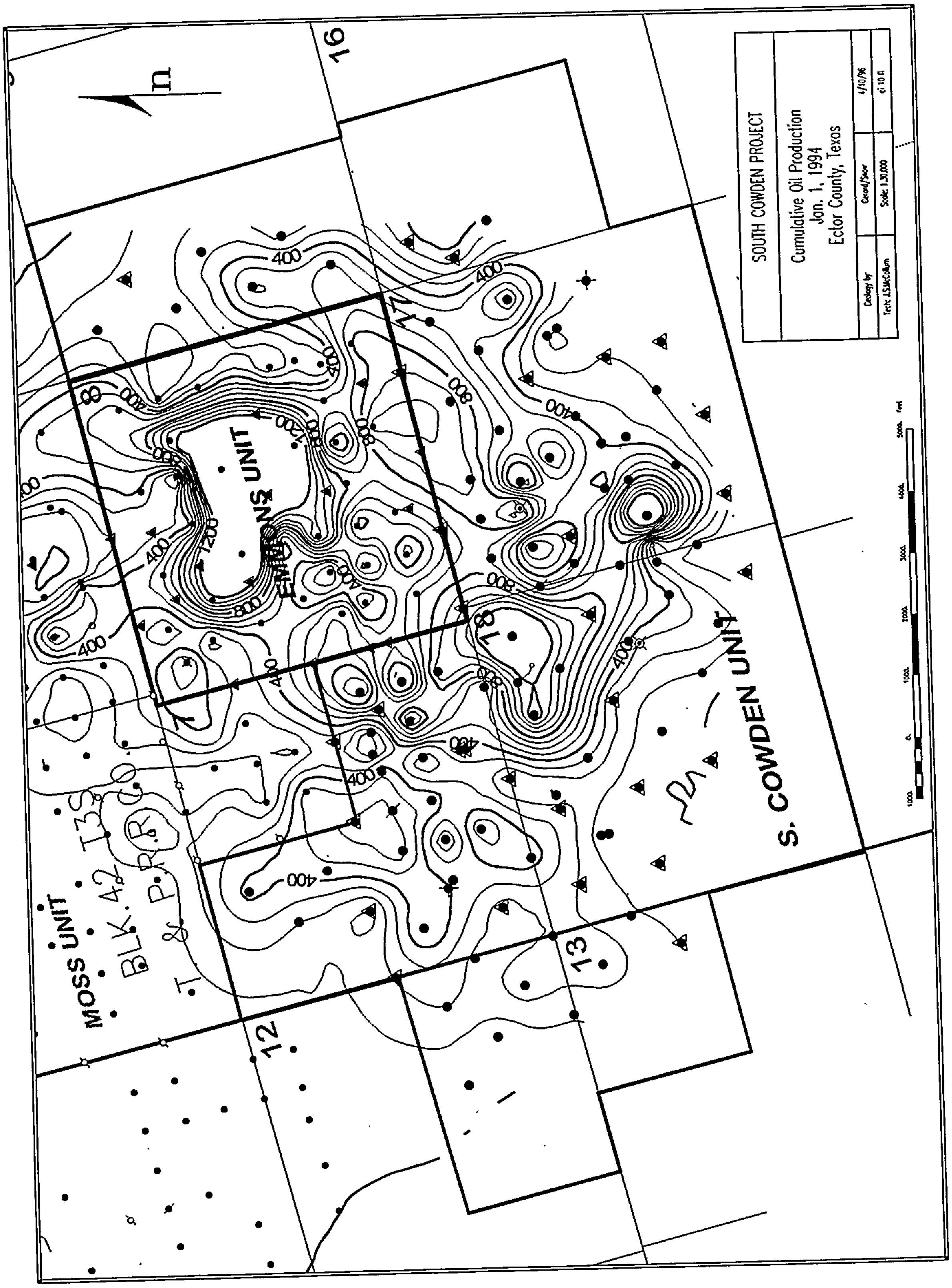
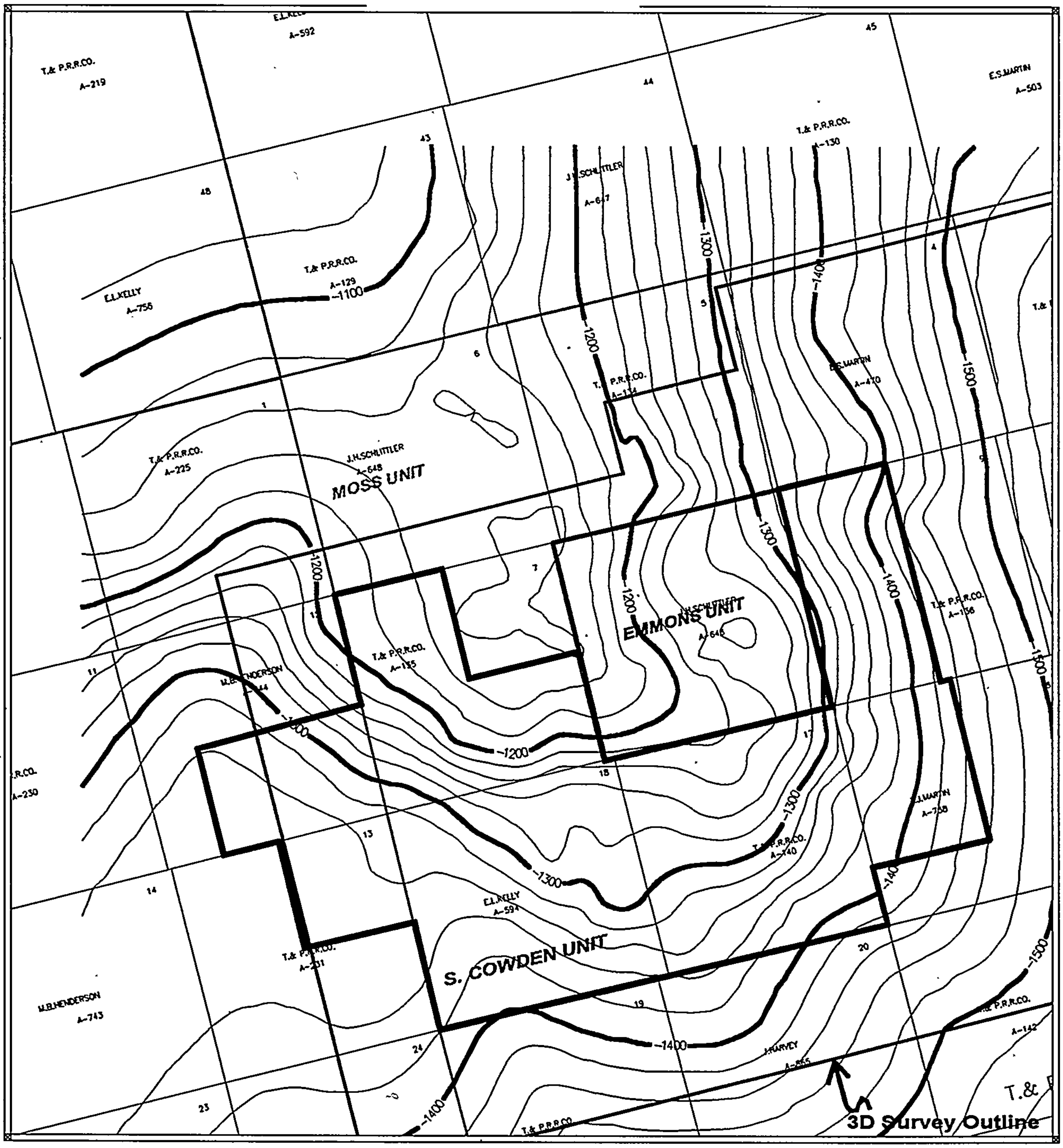

SOUTH COWDEN PROJECT
Cumulative Oil Production
Jan. 1, 1994
Ector County, Texas
EMMONS UNIT
S. COWDEN UNIT
MOSS UNIT
BLK. 42 T3S
T & P.R.R.CO.
16
17
8
18
13
12
400
800
1200

FIGURE 7



LEGEND

- Oil Well
- Water Injector
- TA'd Oil
- TA'd Injector
- P & A
- Shut-In Oil
- Shut-In Injector
- Drilled & Abandoned

n

SOUTH COWDEN PROJECT

Grayburg Structure
South Cowden Field
Ector County, Texas

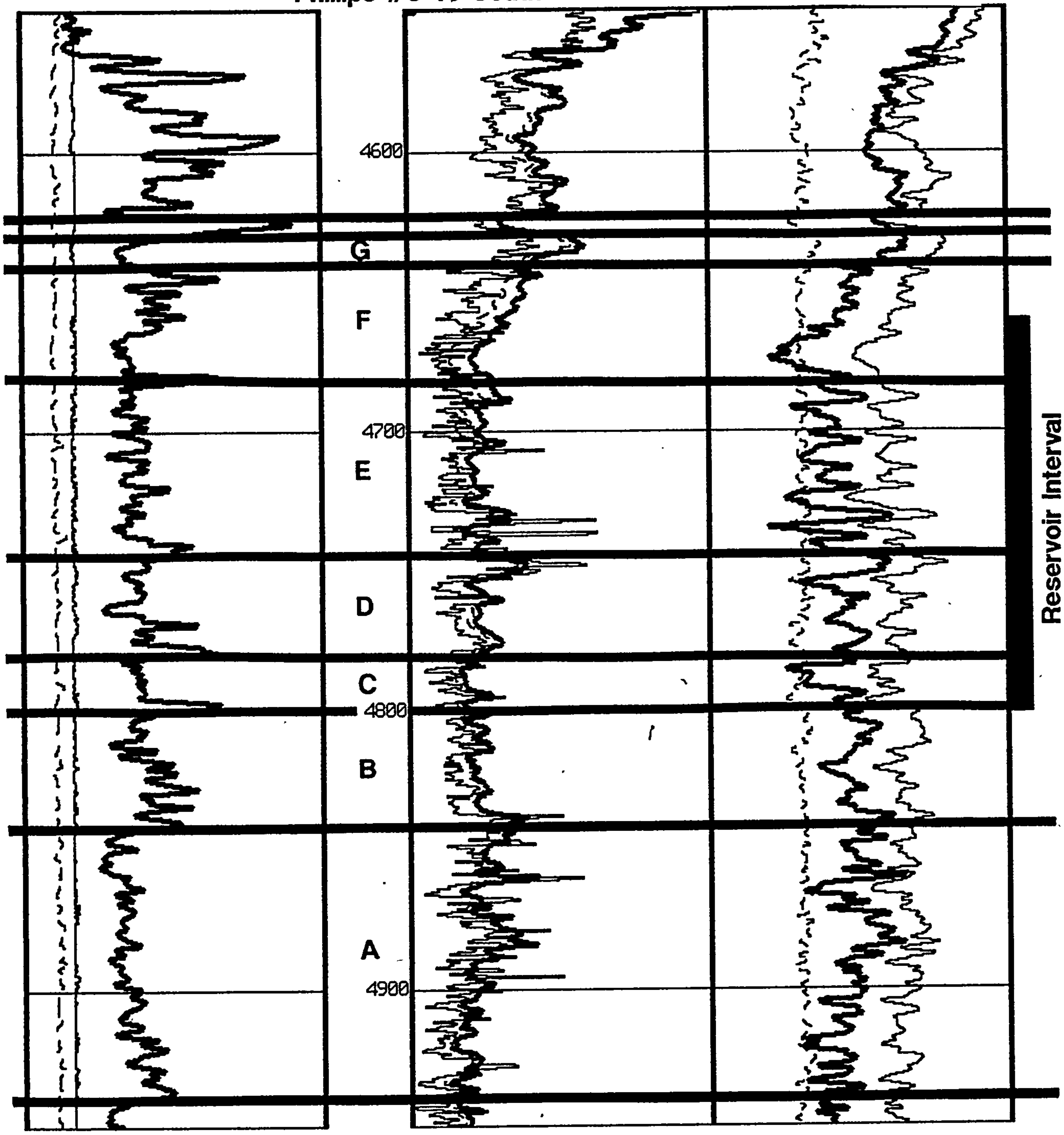
Geology by:	J.V. Johnson	4/10/96
Graf: J.S.McCollum	Scale: 1:38,000	

0.2 0. 0.2 0.4 0.6 0.8 1. miles

TYPE LOG

FIGURE 8

Phillips #8-19 South Cowden Ut.



DRHO G/C3 (-.1 – .9)	md FEET	LLD OHMM (1 – 10000)	PEF (0 – 10)
CALI IN (6 – 16)		LLS OHMM (1 – 10000)	NPHI %LS (40 – -10)
GR GAPI (0 – 100)		MSFL OHMM (1 – 10000)	RHOB g/cc (2 – 3)

FIGURE 9

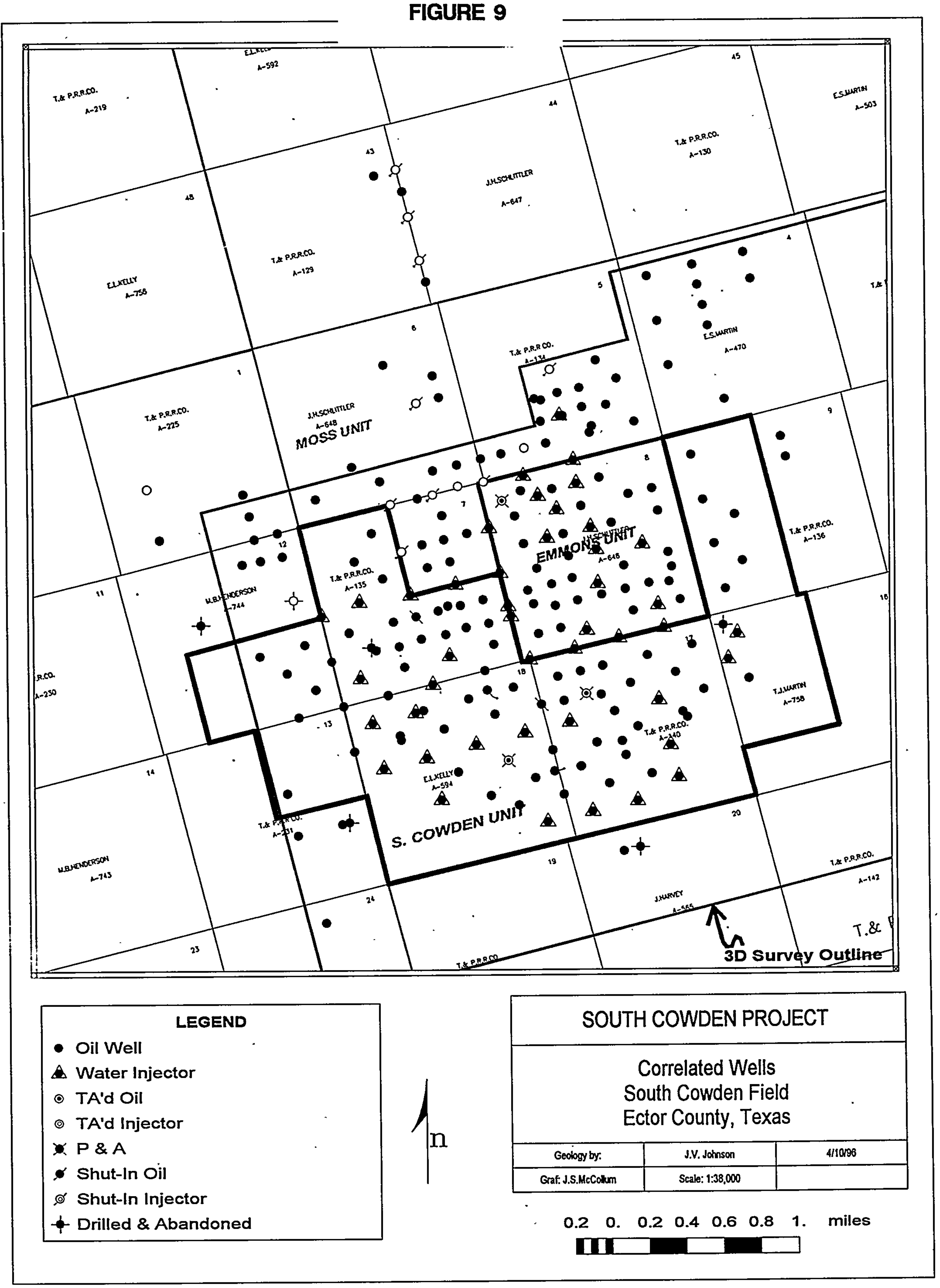

MOSS UNIT
EMMONS UNIT
S. COWDEN UNIT
3D Survey Outline
LEGEND
Oil Well
Water Injector
TA'd Oil
TA'd Injector
P & A
Shut-In Oil
Shut-In Injector
Drilled & Abandoned
SOUTH COWDEN PROJECT
Correlated Wells
South Cowden Field
Ector County, Texas
Geology by:
J.V. Johnson
4/10/96
Graf: J.S.McCollum
Scale: 1:38,000
0.2 0. 0.2 0.4 0.6 0.8 1. miles
n

FIGURE 10

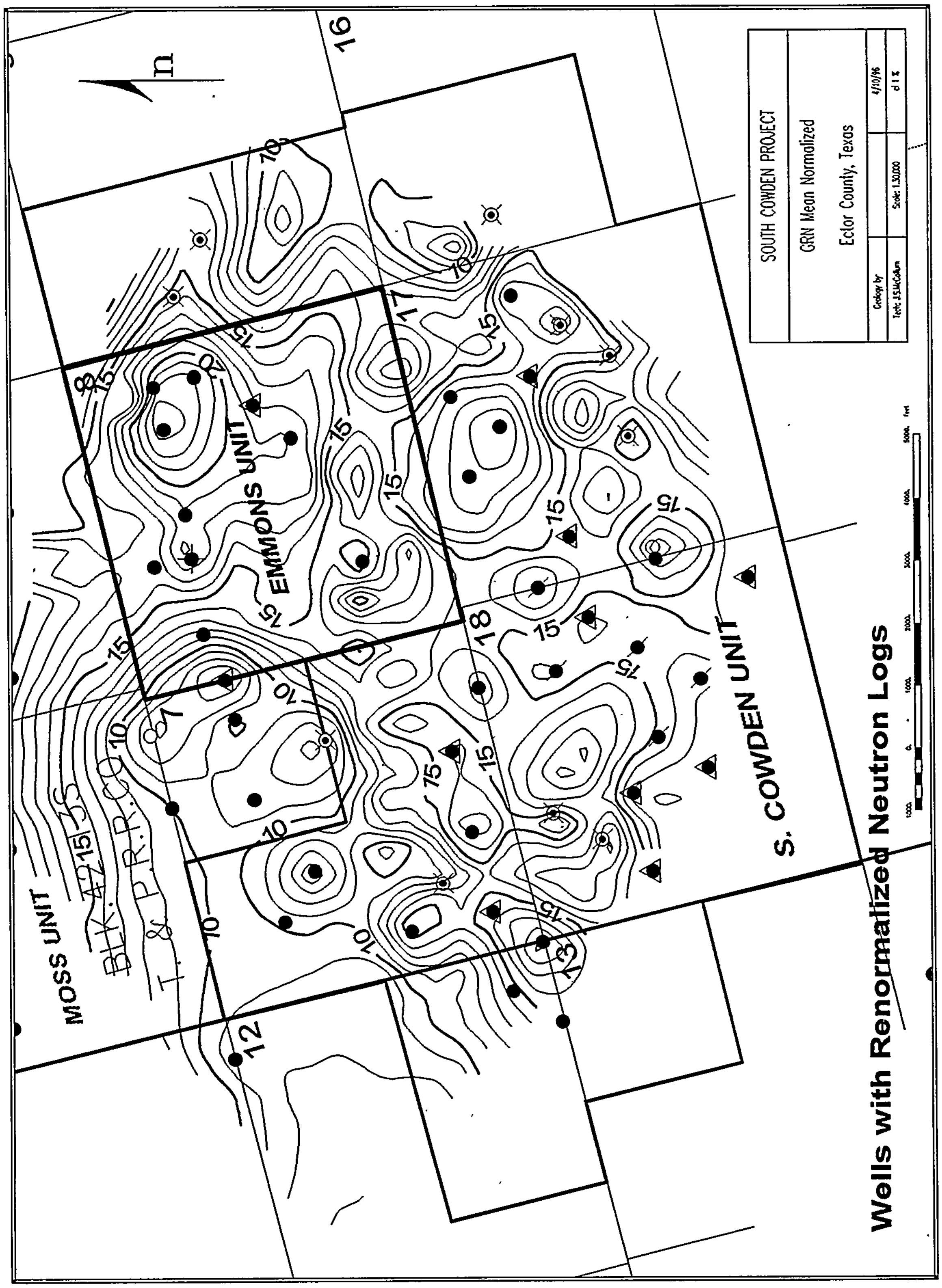
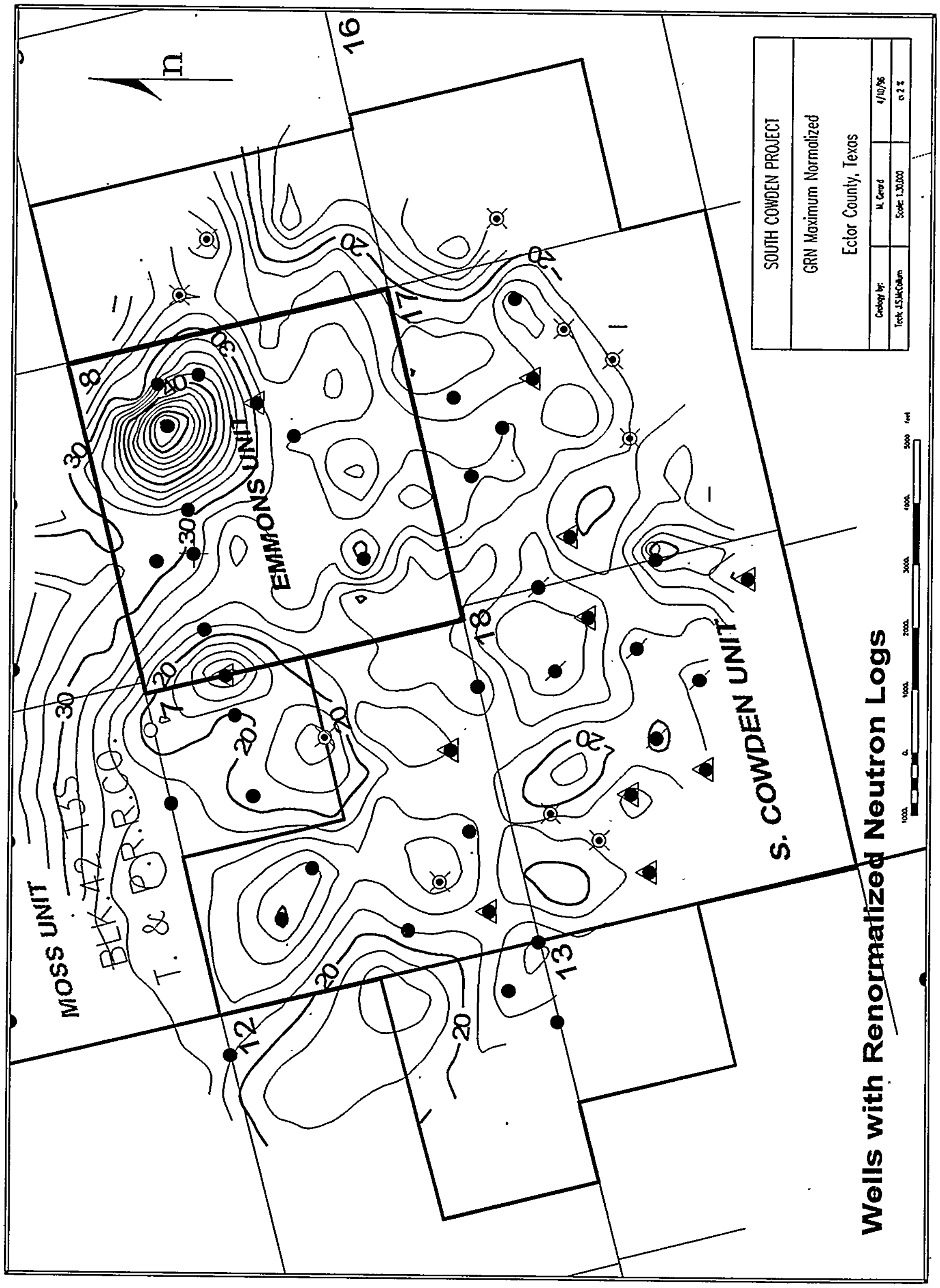

SOUTH COWDEN PROJECT
GRN Mean Normalized
Ector County, Texas
EMMONS UNIT
S. COWDEN UNIT
MOSS UNIT
Wells with Renormalized Neutron Logs

FIGURE 11



SOUTH COWDEN PROJECT
GRN Maximum Normalized
Ector County, Texas
Wells with Renormalized Neutron Logs
EMMONS UNIT
S. COWDEN UNIT
MOSS UNIT

FIGURE 12

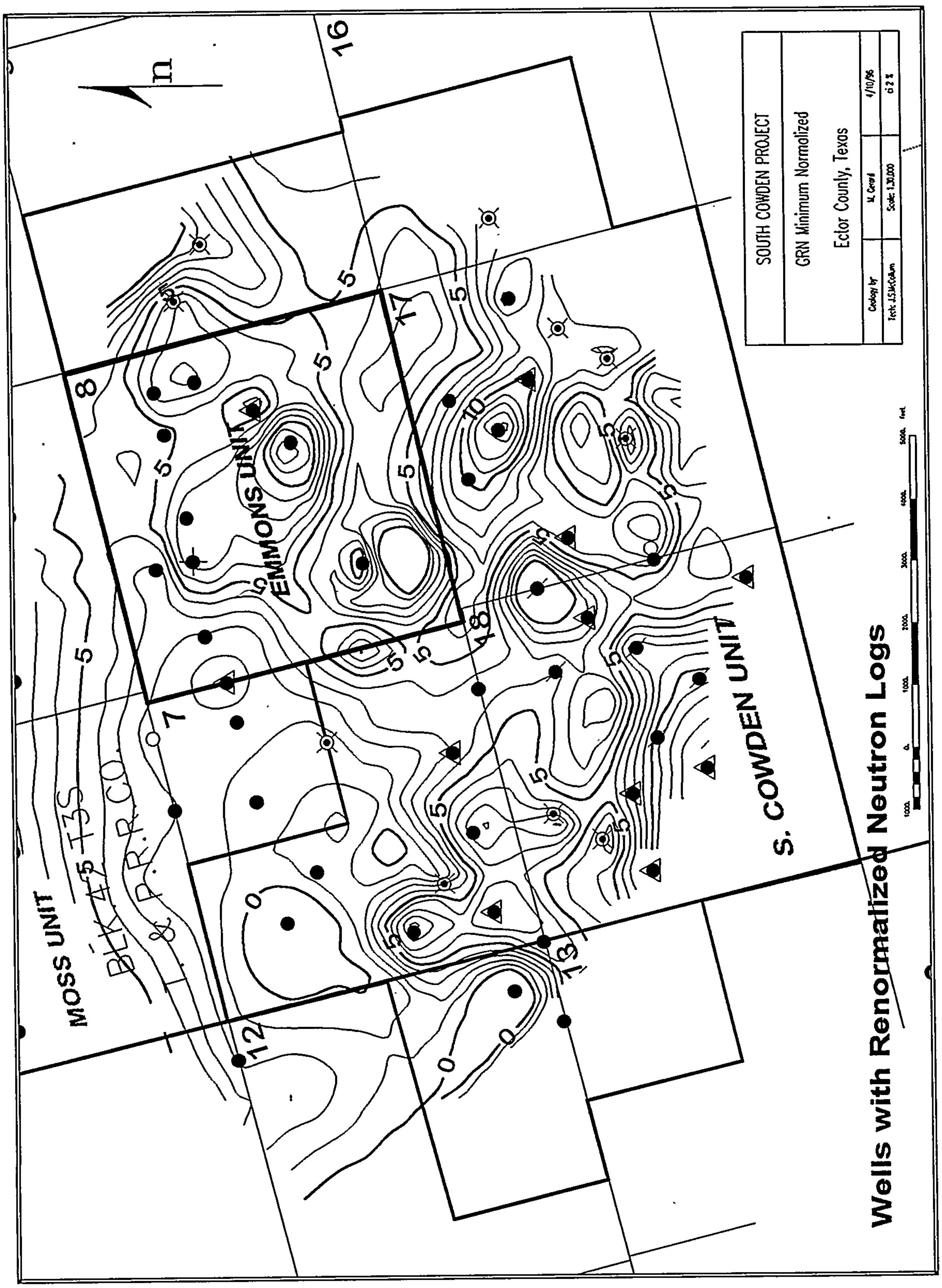
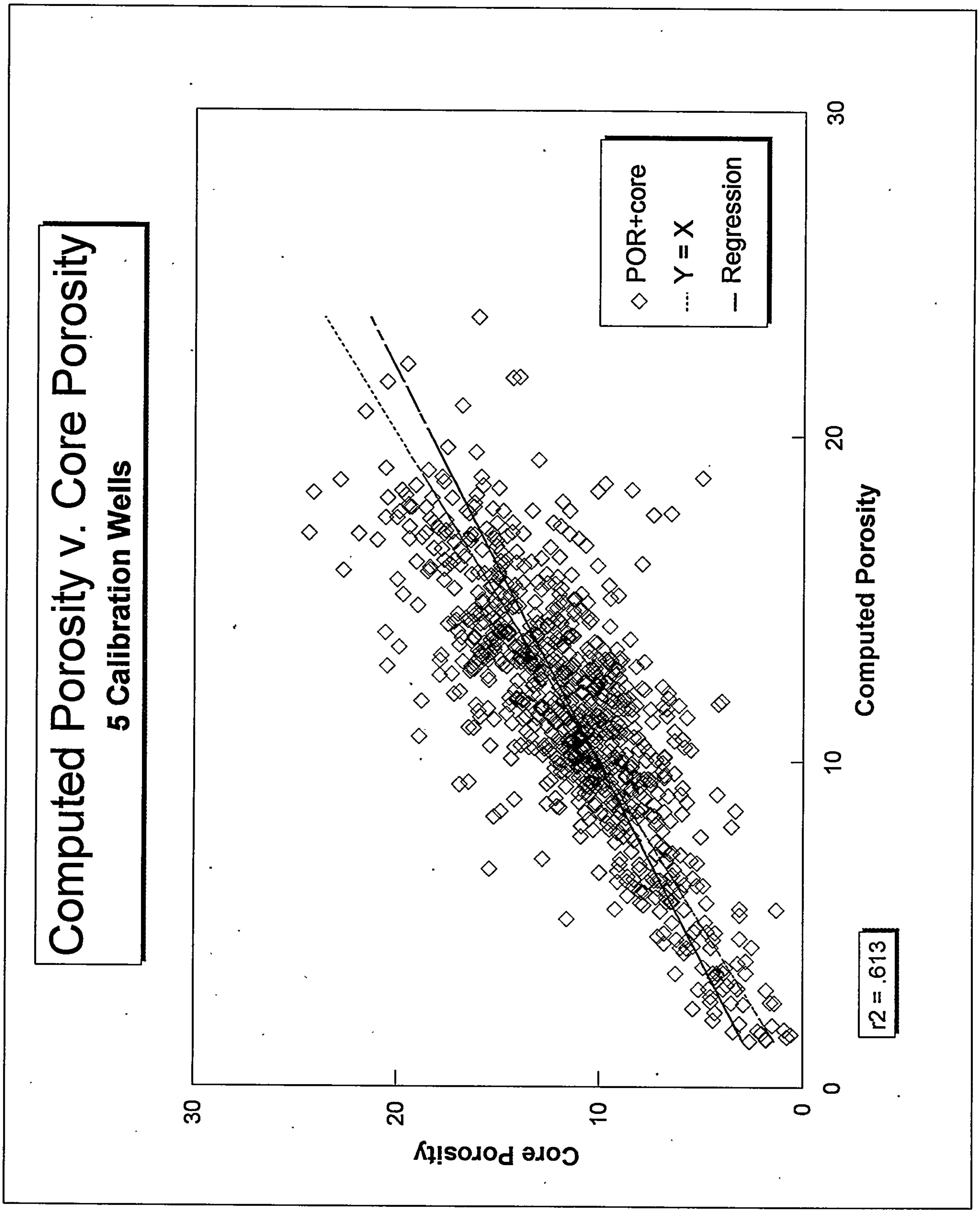
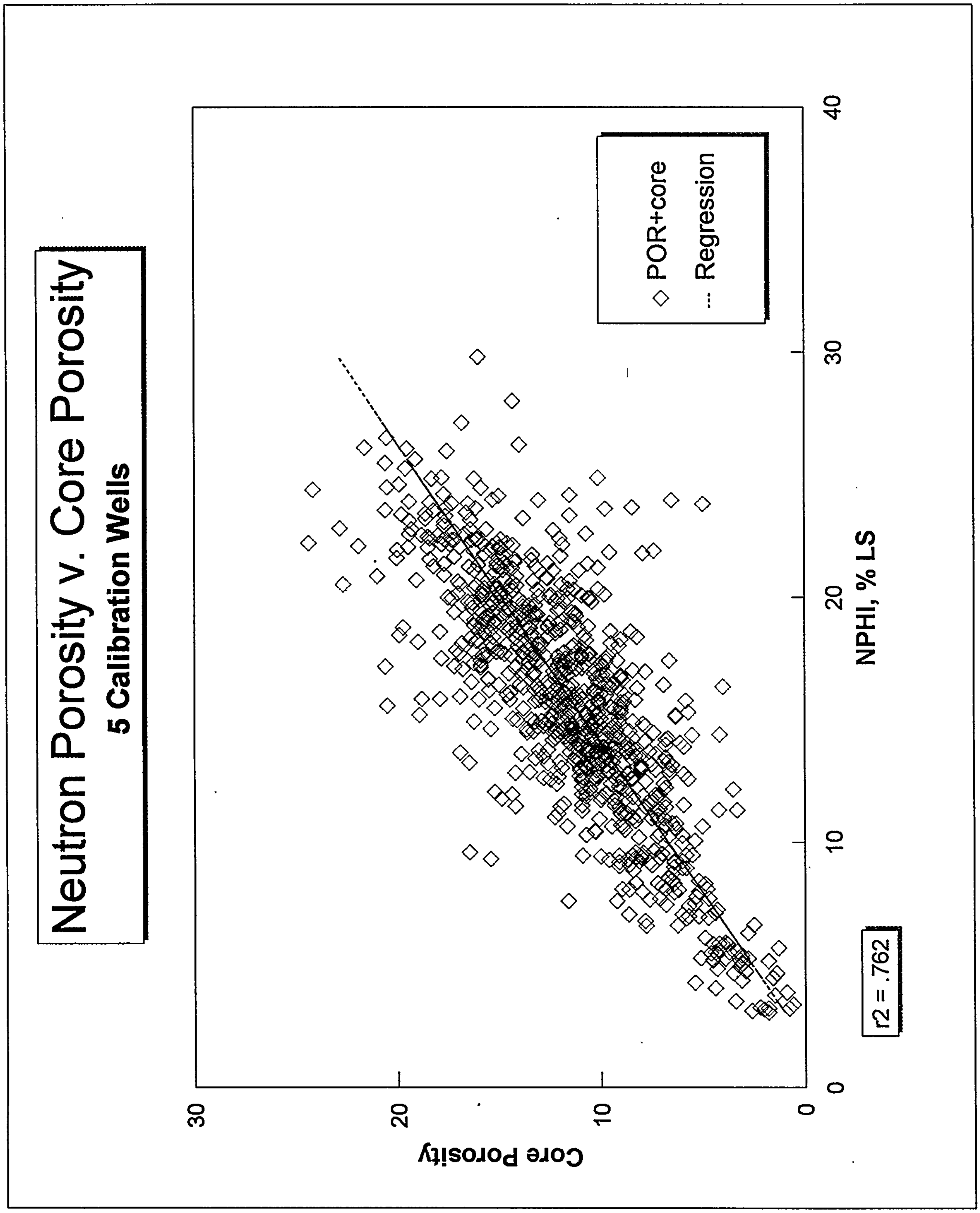

SOUTH COWDEN PROJECT
GRN Minimum Normalized
Ector County, Texas
Wells with Renormalized Neutron Logs
MOSS UNIT
EMMONS UNIT
S. COWDEN UNIT
BLK 47 T3S
T. & P. R.R. CO.

FIGURE 13



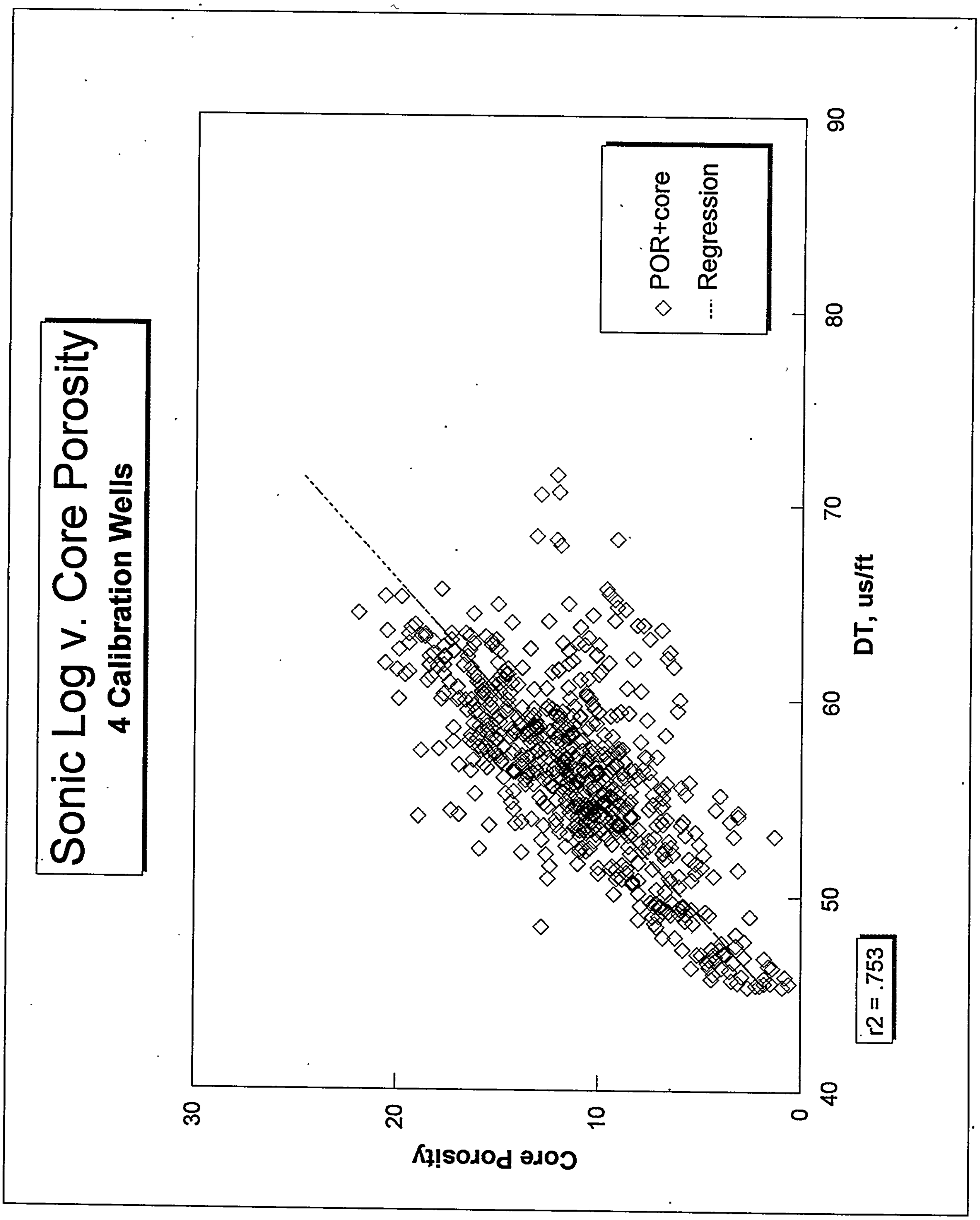
Computed Porosity v. Core Porosity
5 Calibration Wells
POR+core
Y = X
Regression
r2 = .613
Core Porosity
Computed Porosity
0
10
20
30
0
10
20
30

FIGURE 14



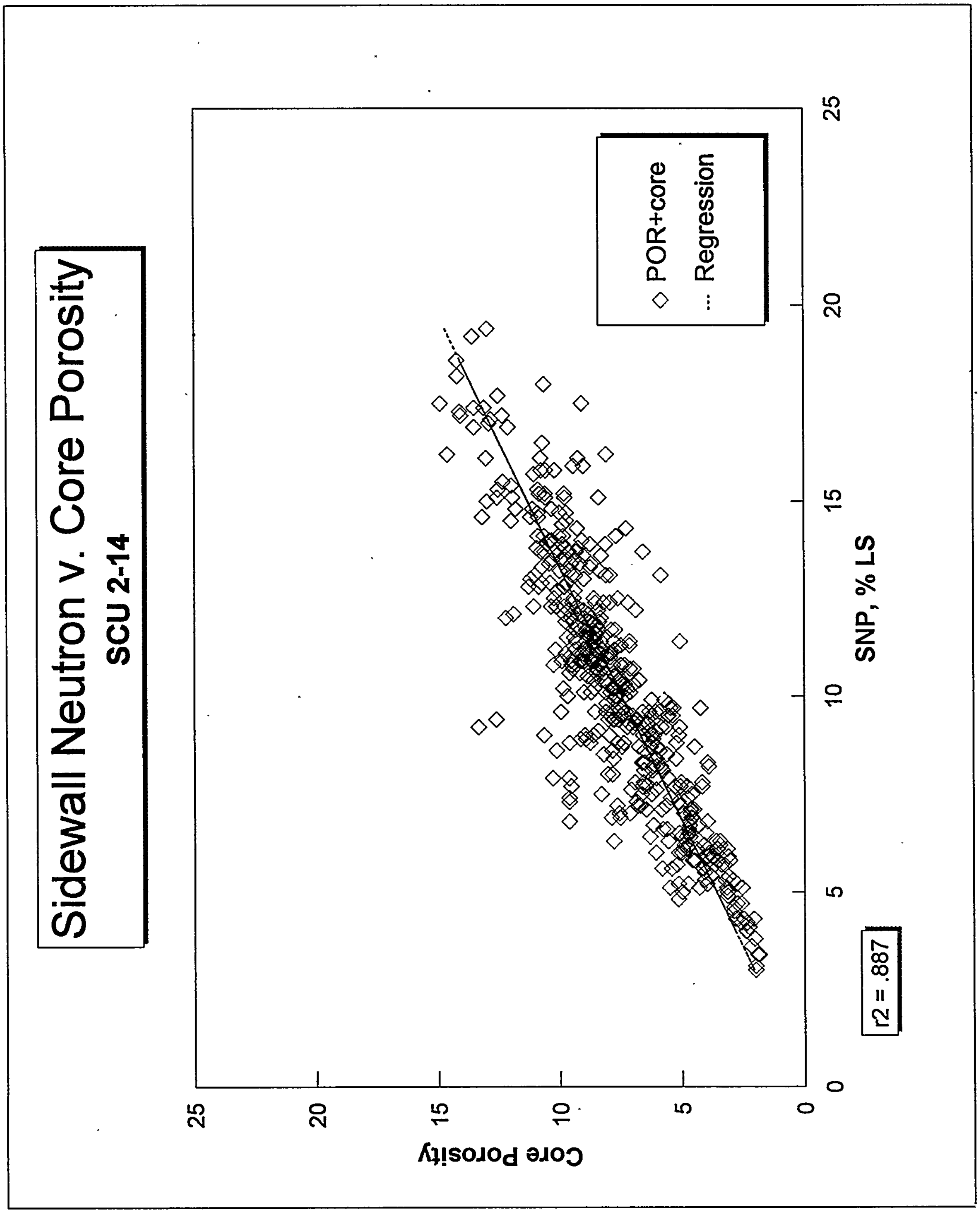
Neutron Porosity v. Core Porosity
5 Calibration Wells
POR+core
Regression
r2 = .762
Core Porosity
NPHI, % LS
0
10
20
30
40

FIGURE 15



Sonic Log v. Core Porosity
4 Calibration Wells
POR+core
Regression
r2 = .753
Core Porosity
DT, us/ft
0
10
20
30
40
50
60
70
80
90

FIGURE 16



Sidewall Neutron v. Core Porosity
SCU 2-14
POR+core
Regression
r2 = .887
Core Porosity
SNP, % LS
0
5
10
15
20
25

FIGURE 17

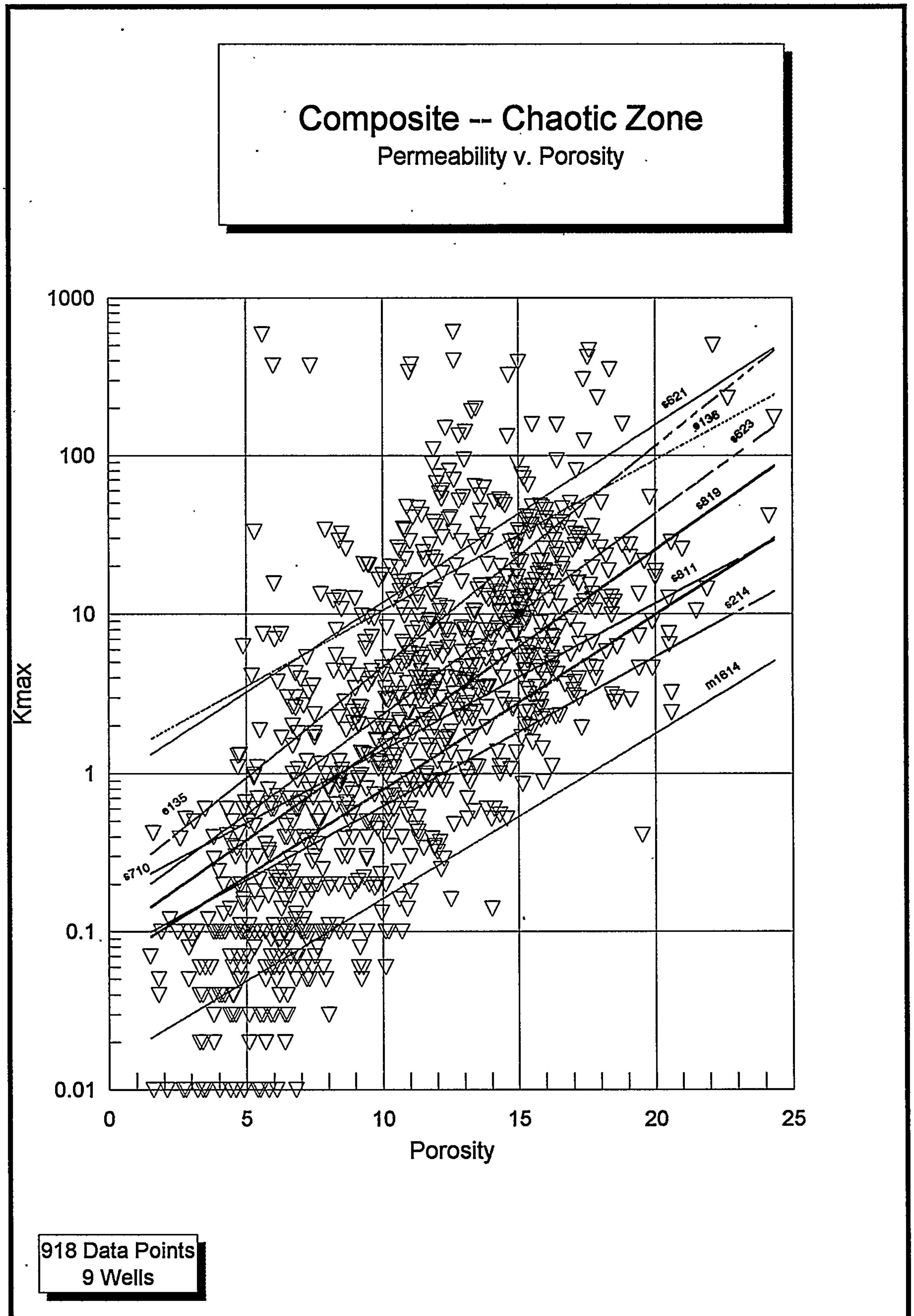
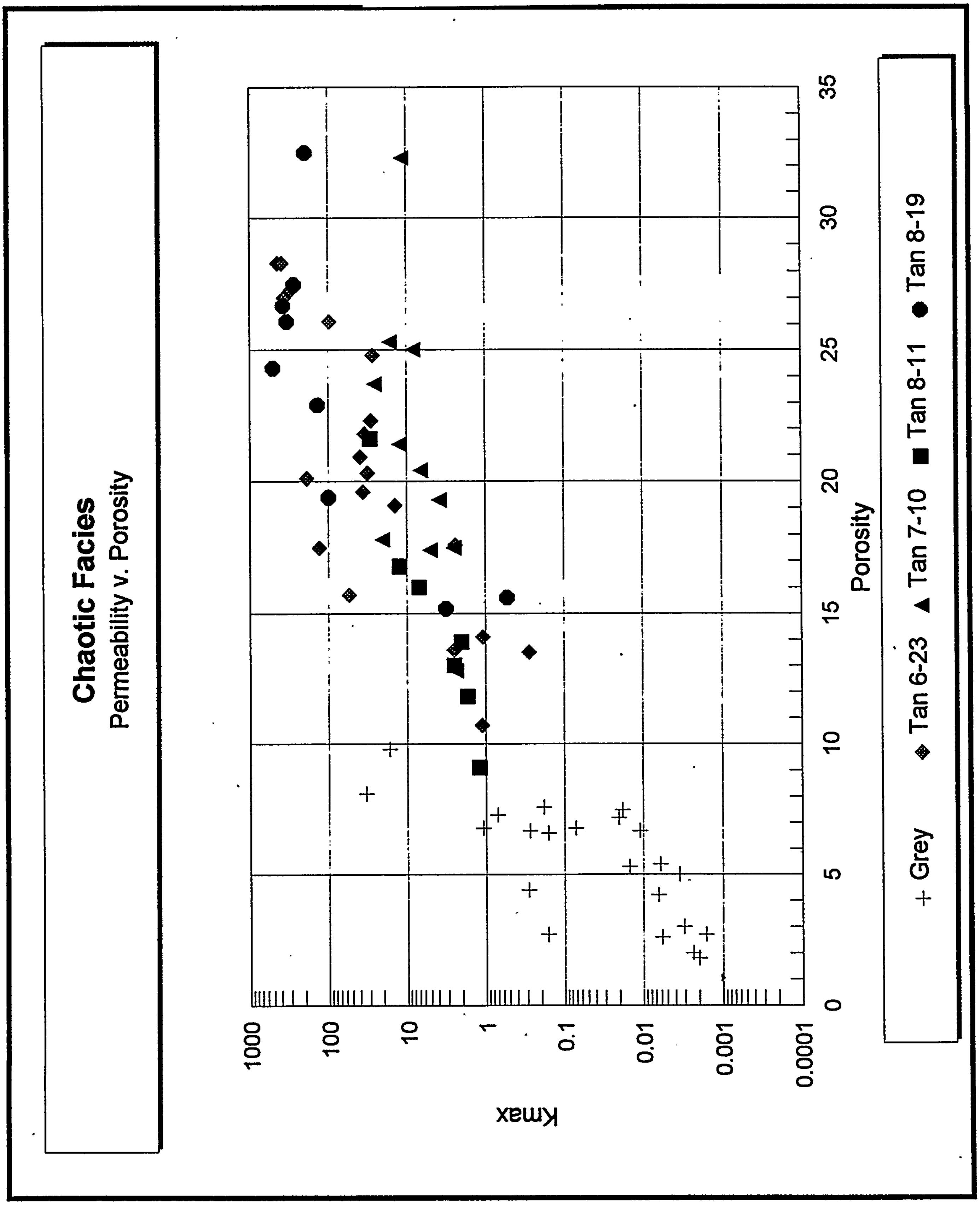

Composite -- Chaotic Zone
Permeability v. Porosity
Kmax
1000
100
10
1
0.1
0.01
0
5
10
15
20
25
Porosity
m1614
918 Data Points
9 Wells

FIGURE 18



Chaotic Facies
Permeability v. Porosity
Kmax
1000
100
10
1
0.1
0.01
0.001
0.0001
0
5
10
15
20
25
30
35
Porosity
Grey
Tan 6-23
Tan 7-10
Tan 8-11
Tan 8-19

FIGURE 19

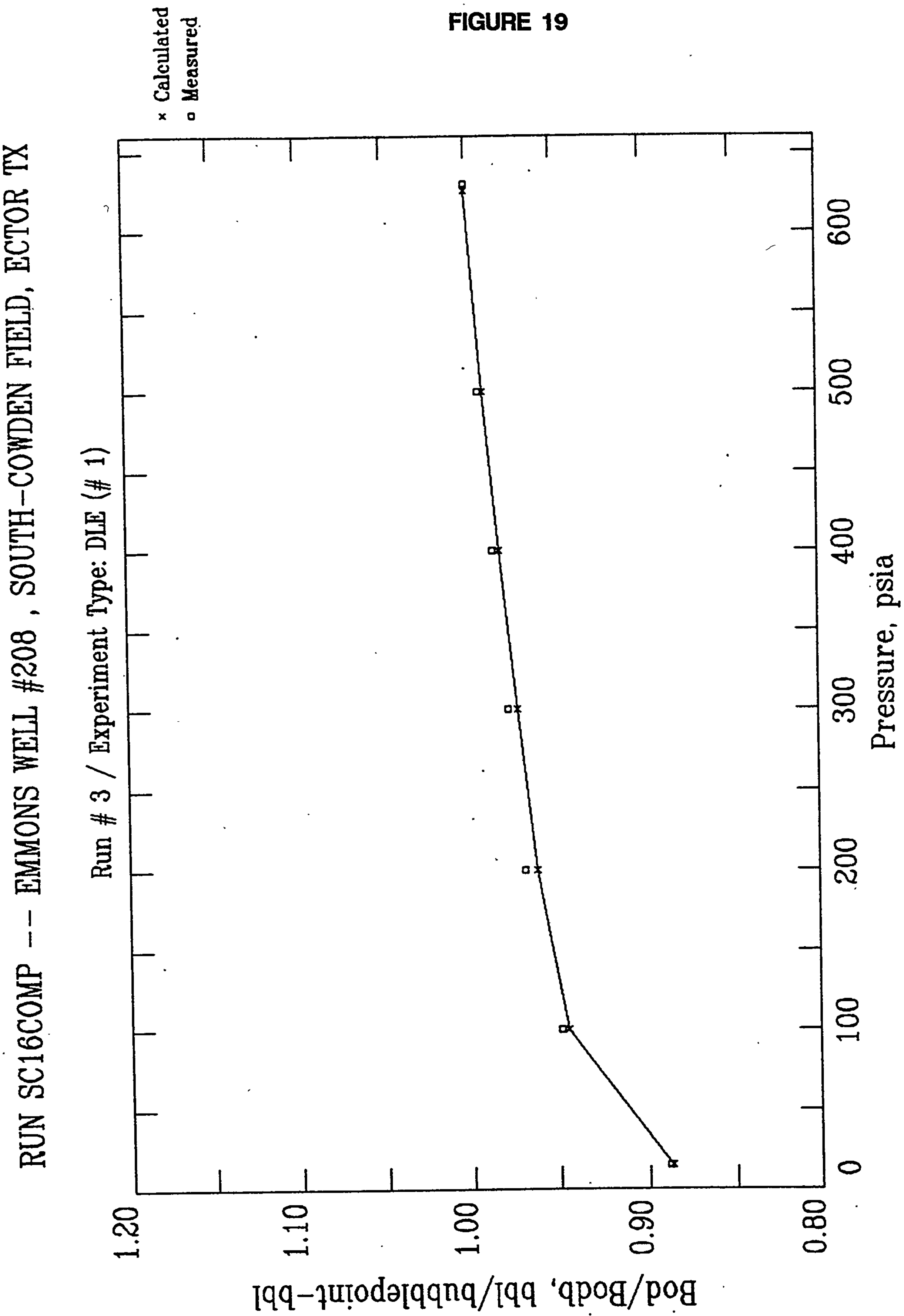

RUN SC16COMP -- EMMONS WELL #208 , SOUTH-COWDEN FIELD, ECTOR TX
Run # 3 / Experiment Type: DLE (# 1)
× Calculated
▫ Measured
Bod/Bodb, bbl/bubblepoint-bbl
1.20
1.10
1.00
0.90
0.80
Pressure, psia
0
100
200
300
400
500
600

FIGURE 20

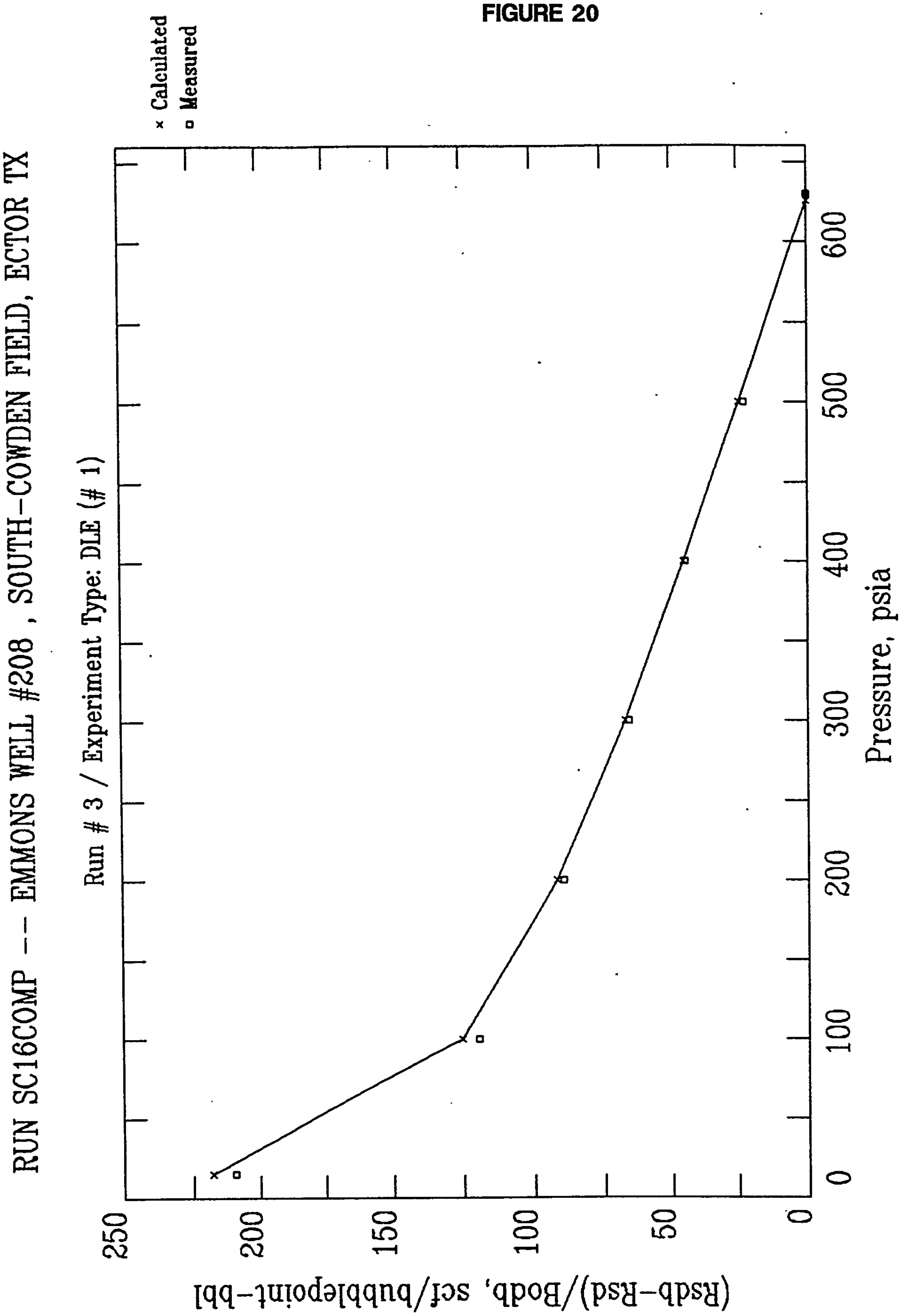

RUN SC16COMP -- EMMONS WELL #208 , SOUTH-COWDEN FIELD, ECTOR TX
Run # 3 / Experiment Type: DLE (# 1)
× Calculated
□ Measured
(Rsdb-Rsd)/Bodb, scf/bubblepoint-bbl
250
200
150
100
50
0
Pressure, psia
0
100
200
300
400
500
600

FIGURE 21

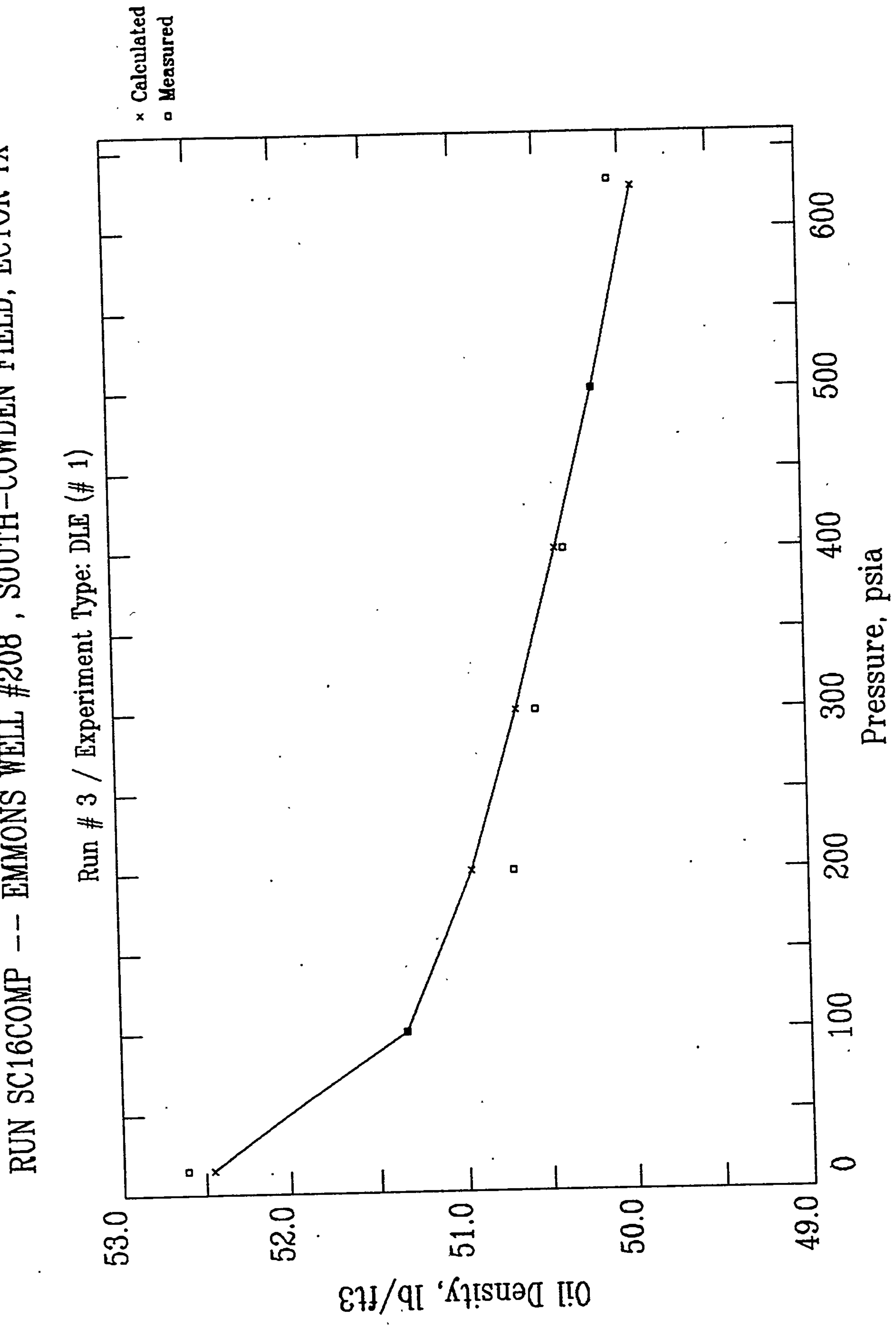
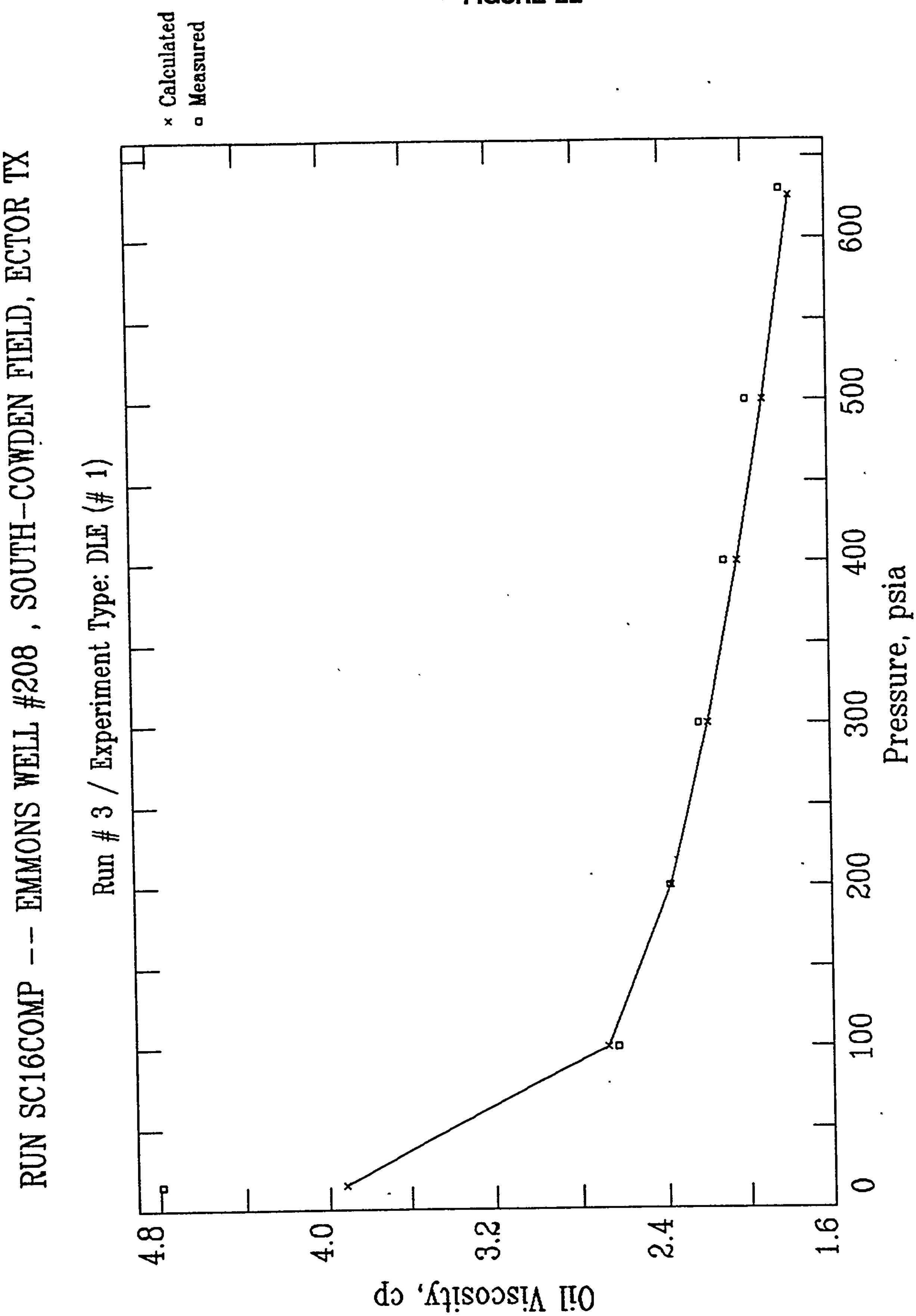

RUN SC16COMP — EMMONS WELL #208 , SOUTH-COWDEN FIELD, ECTOR TX
Run # 3 / Experiment Type: DLE (# 1)
× Calculated
▫ Measured
Oil Density, lb/ft3
53.0
52.0
51.0
50.0
49.0
Pressure, psia
0
100
200
300
400
500
600

FIGURE 22



RUN SC16COMP -- EMMONS WELL #208 , SOUTH-COWDEN FIELD, ECTOR TX
Run # 3 / Experiment Type: DLE (# 1)
× Calculated
▫ Measured
Oil Viscosity, cp
4.8
4.0
3.2
2.4
1.6
Pressure, psia
0
100
200
300
400
500
600

FIGURE 23

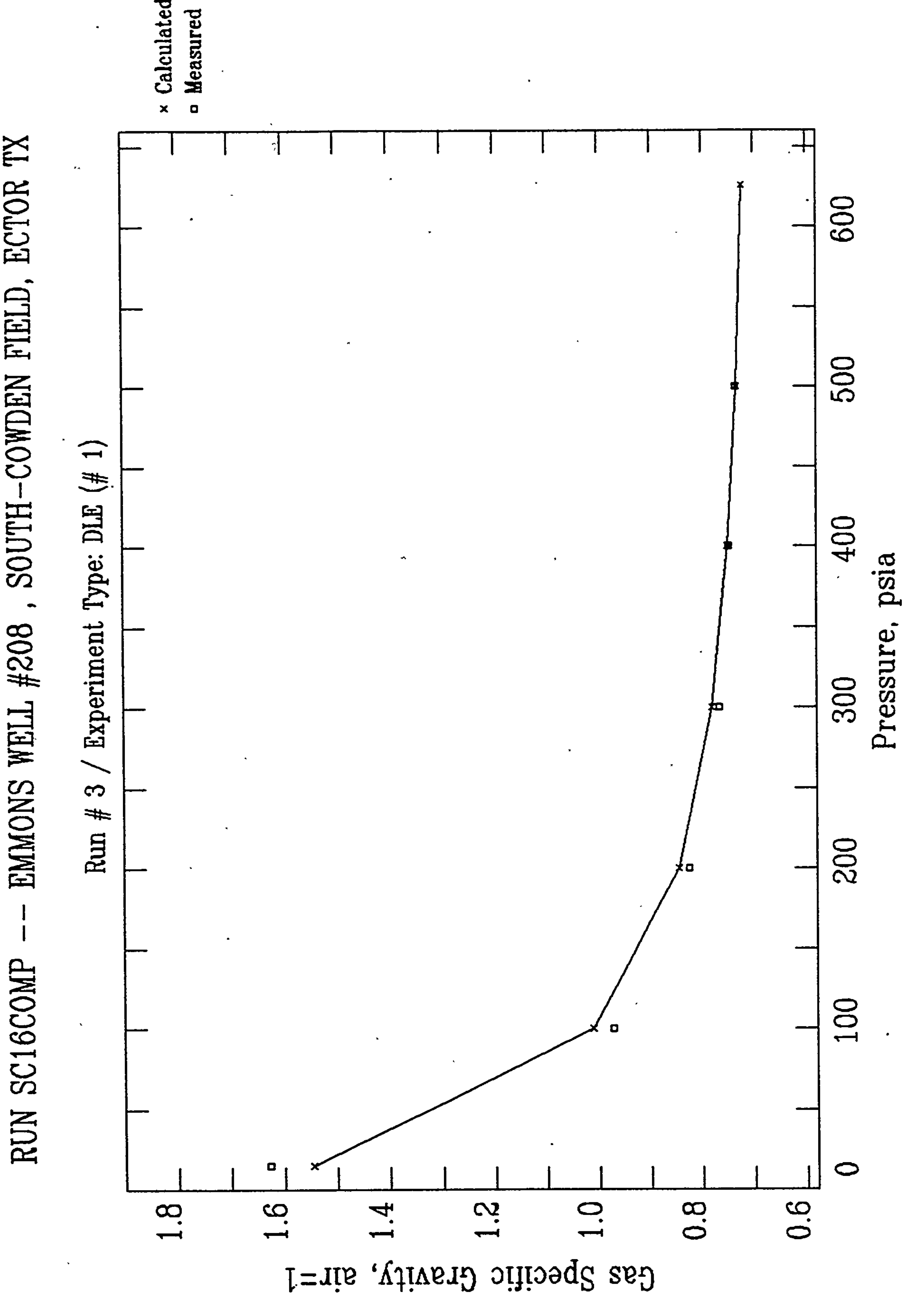
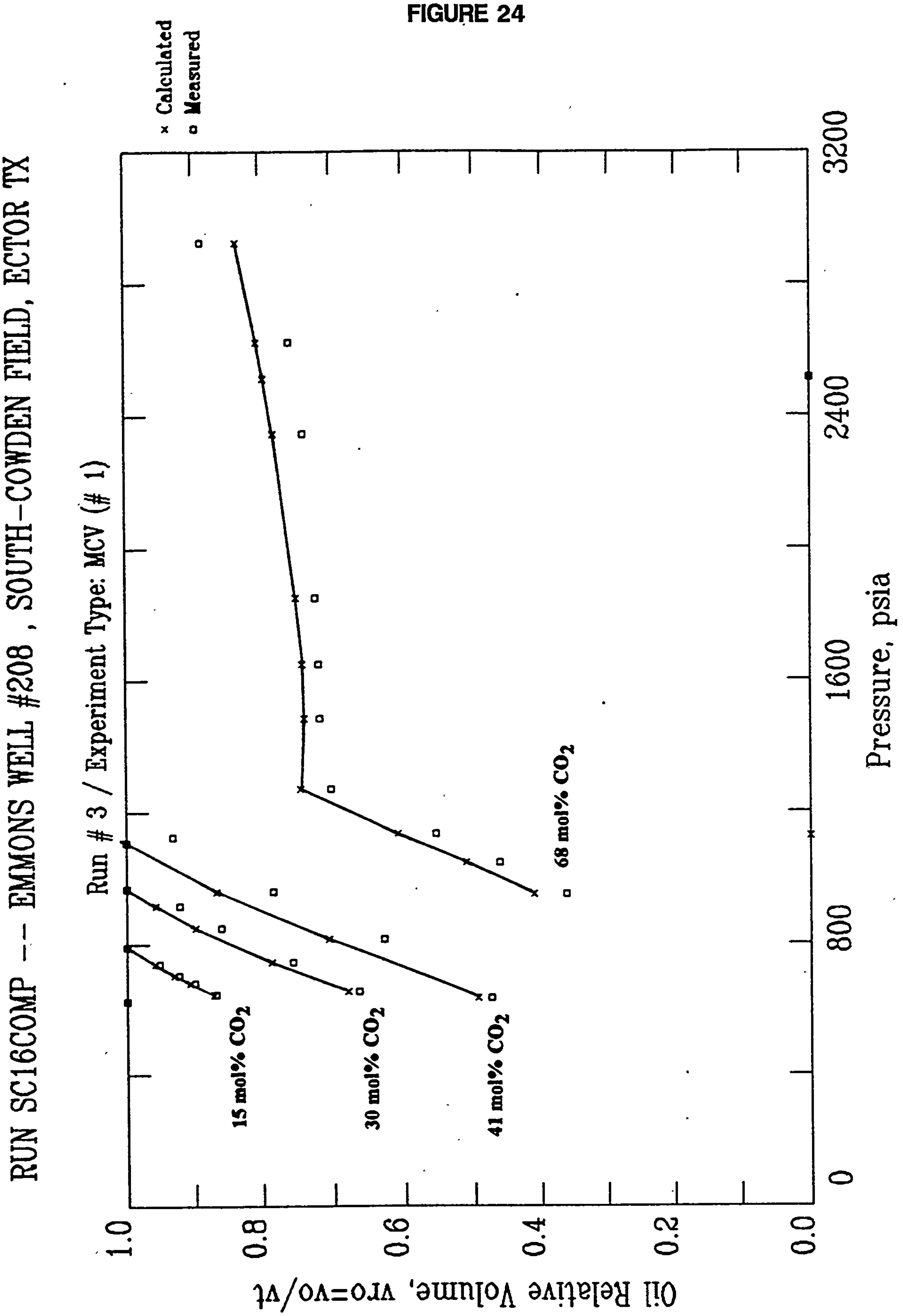

RUN SC16COMP -- EMMONS WELL #208 , SOUTH-COWDEN FIELD, ECTOR TX
Run # 3 / Experiment Type: DLE (# 1)
× Calculated
□ Measured
Gas Specific Gravity, air=1
1.8
1.6
1.4
1.2
1.0
0.8
0.6
Pressure, psia
0
100
200
300
400
500
600

FIGURE 24



RUN SC16COMP -- EMMONS WELL #208 , SOUTH-COWDEN FIELD, ECTOR TX
Run # 3 / Experiment Type: MCV (# 1)
× Calculated
□ Measured
15 mol% CO_2
30 mol% CO_2
41 mol% CO_2
68 mol% CO_2
Oil Relative Volume, vro=vo/vt
1.0
0.8
0.6
0.4
0.2
0.0
Pressure, psia
0
800
1600
2400
3200

FIGURE 25

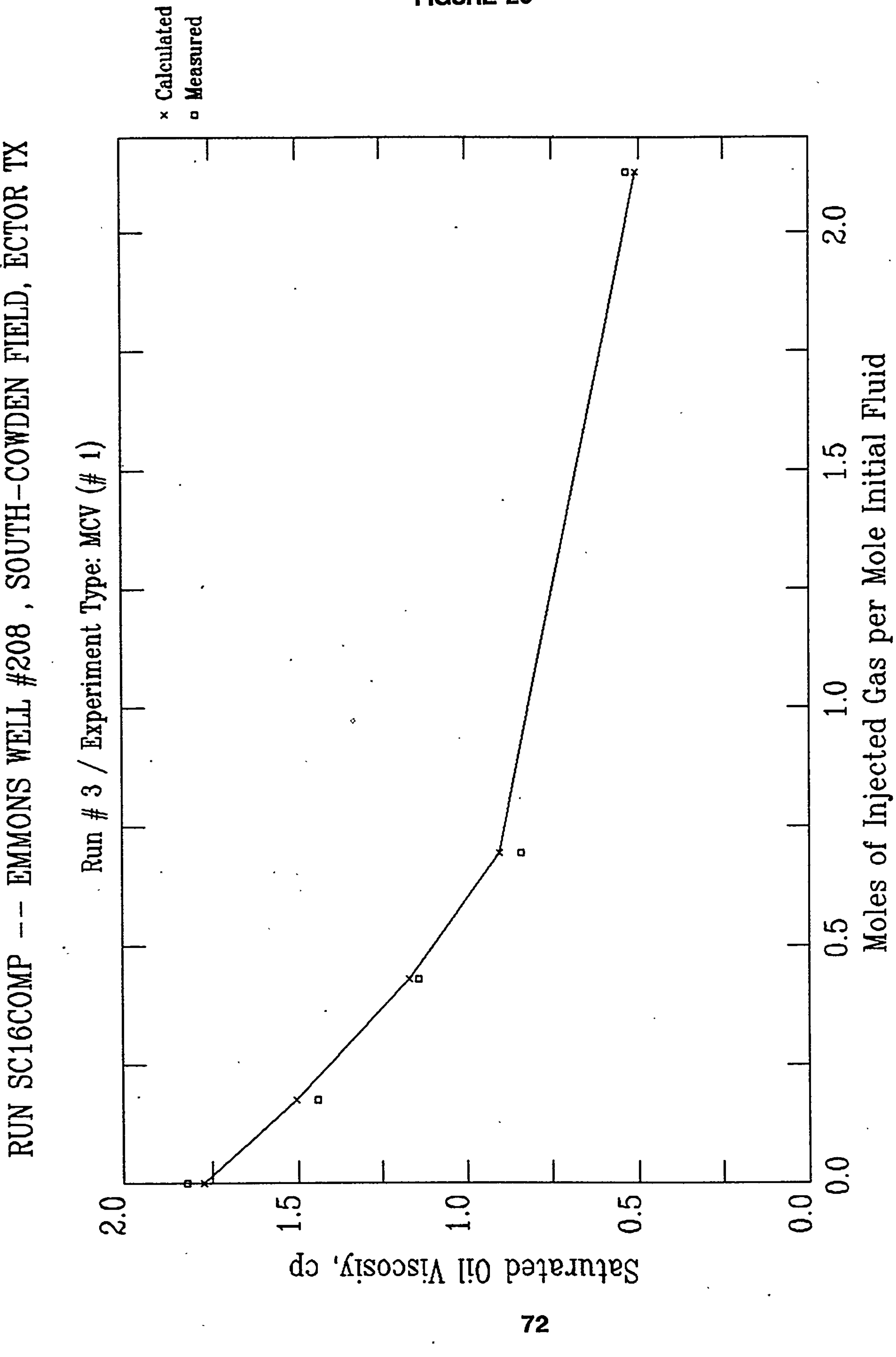
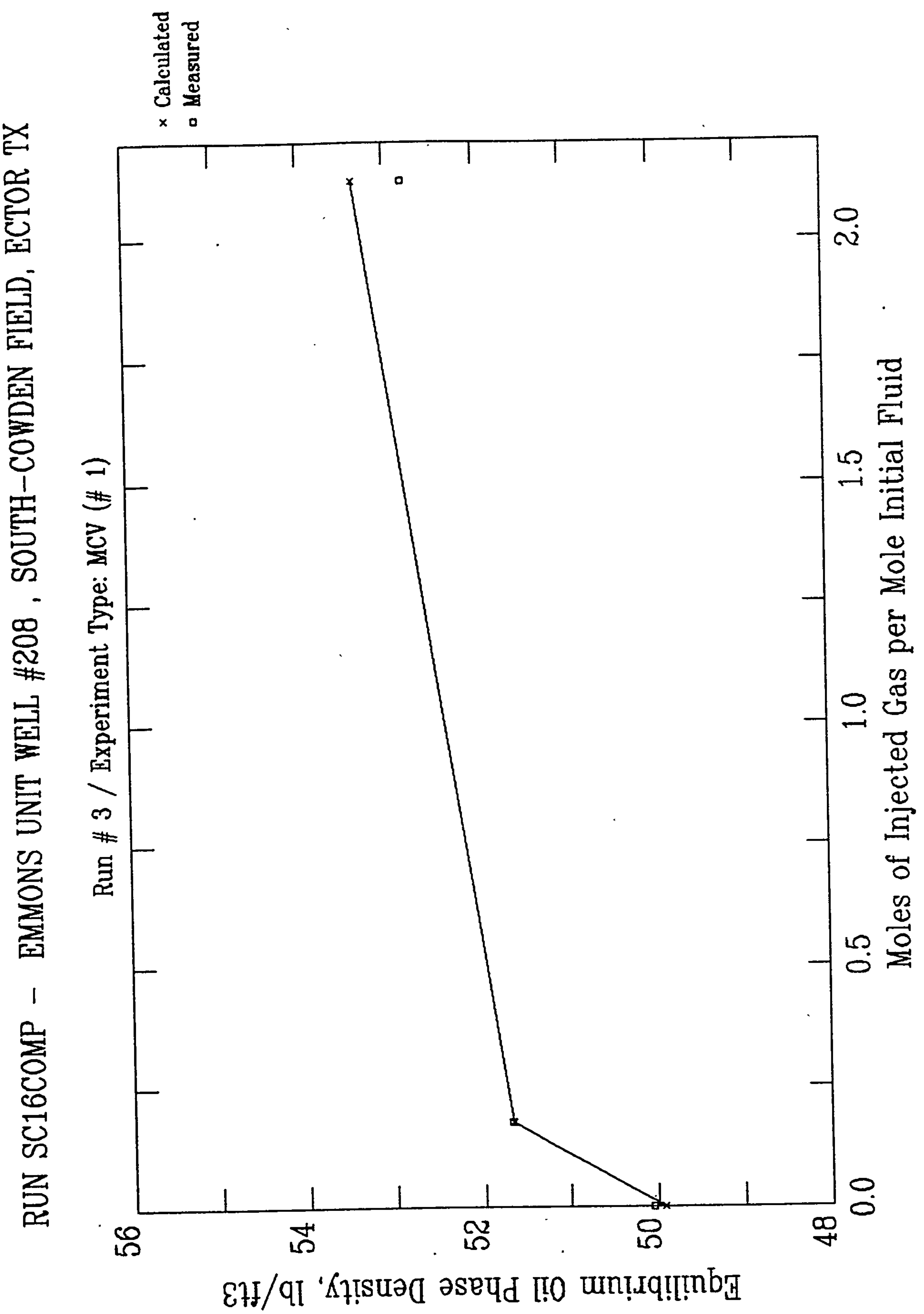

RUN SC16COMP --- EMMONS WELL #208 , SOUTH-COWDEN FIELD, ECTOR TX
Run # 3 / Experiment Type: MCV (# 1)
× Calculated
▫ Measured
Saturated Oil Viscosity, cp
Moles of Injected Gas per Mole Initial Fluid
0.0
0.5
1.0
1.5
2.0

FIGURE 26



RUN SC16COMP - EMMONS UNIT WELL #208 , SOUTH-COWDEN FIELD, ECTOR TX
Run # 3 / Experiment Type: MCV (# 1)
× Calculated
▫ Measured
56
54
52
50
48
Equilibrium Oil Phase Density, lb/ft3
0.0
0.5
1.0
1.5
2.0
Moles of Injected Gas per Mole Initial Fluid

FIGURE 27

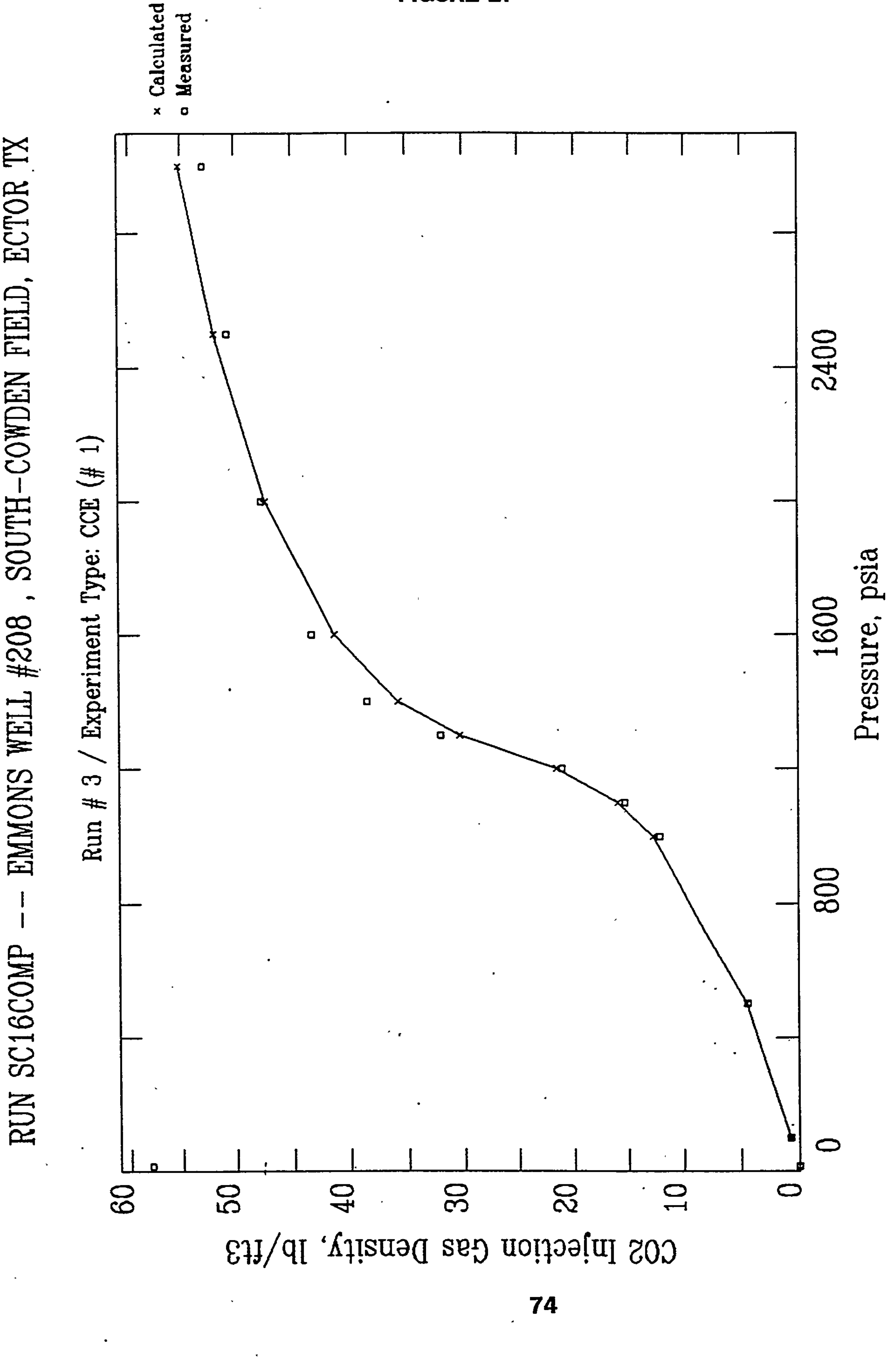
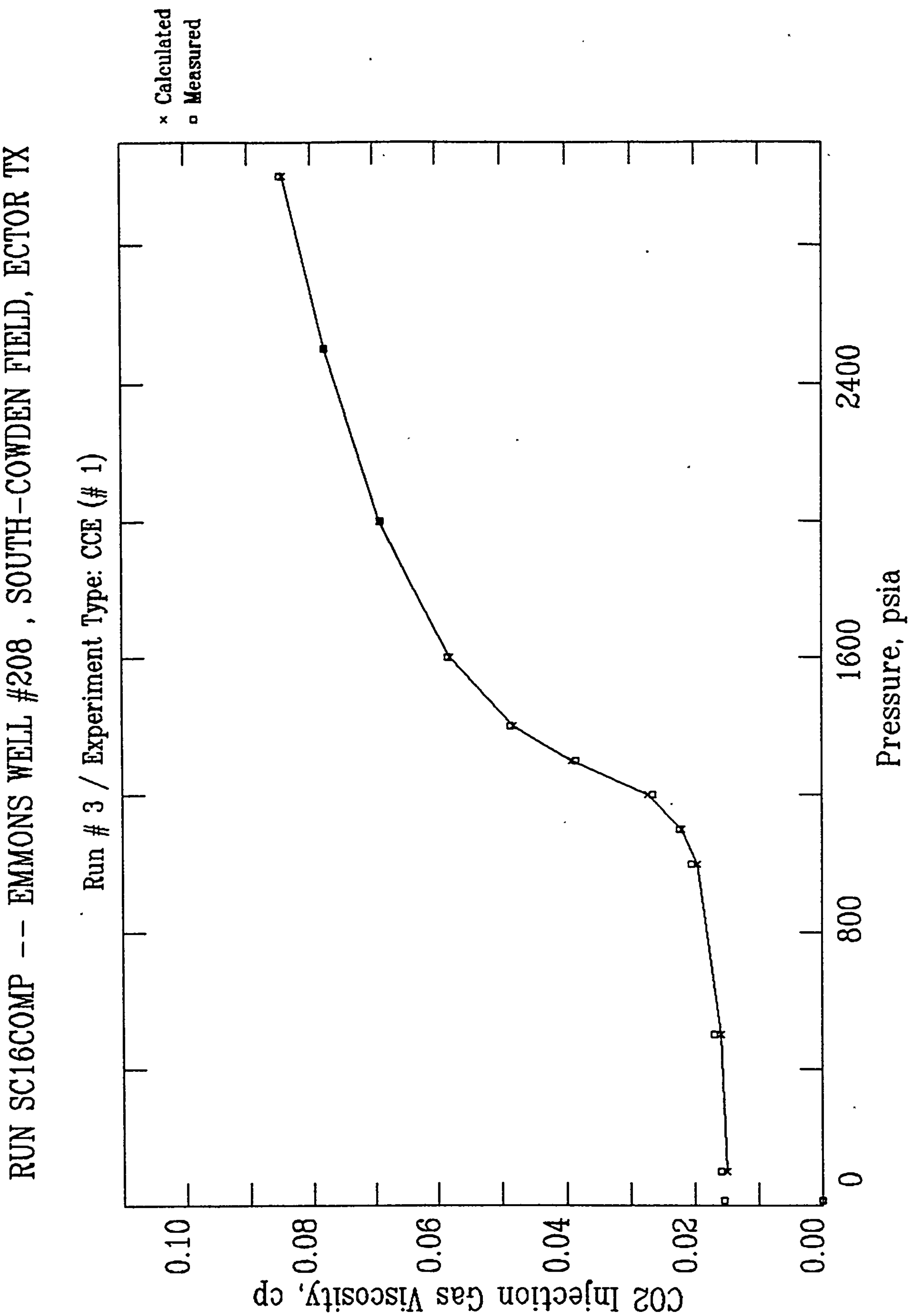

RUN SC16COMP -- EMMONS WELL #208 , SOUTH-COWDEN FIELD, ECTOR TX
Run # 3 / Experiment Type: CCE (# 1)
× Calculated
□ Measured
CO2 Injection Gas Density, lb/ft3
0
10
20
30
40
50
60
Pressure, psia
0
800
1600
2400

FIGURE 28



RUN SC16COMP -- EMMONS WELL #208 , SOUTH-COWDEN FIELD, ECTOR TX
Run # 3 / Experiment Type: CCE (# 1)
× Calculated
□ Measured
0
800
1600
2400
Pressure, psia
0.00
0.02
0.04
0.06
0.08
0.10
C02 Injection Gas Viscosity, cp

FIGURE 29

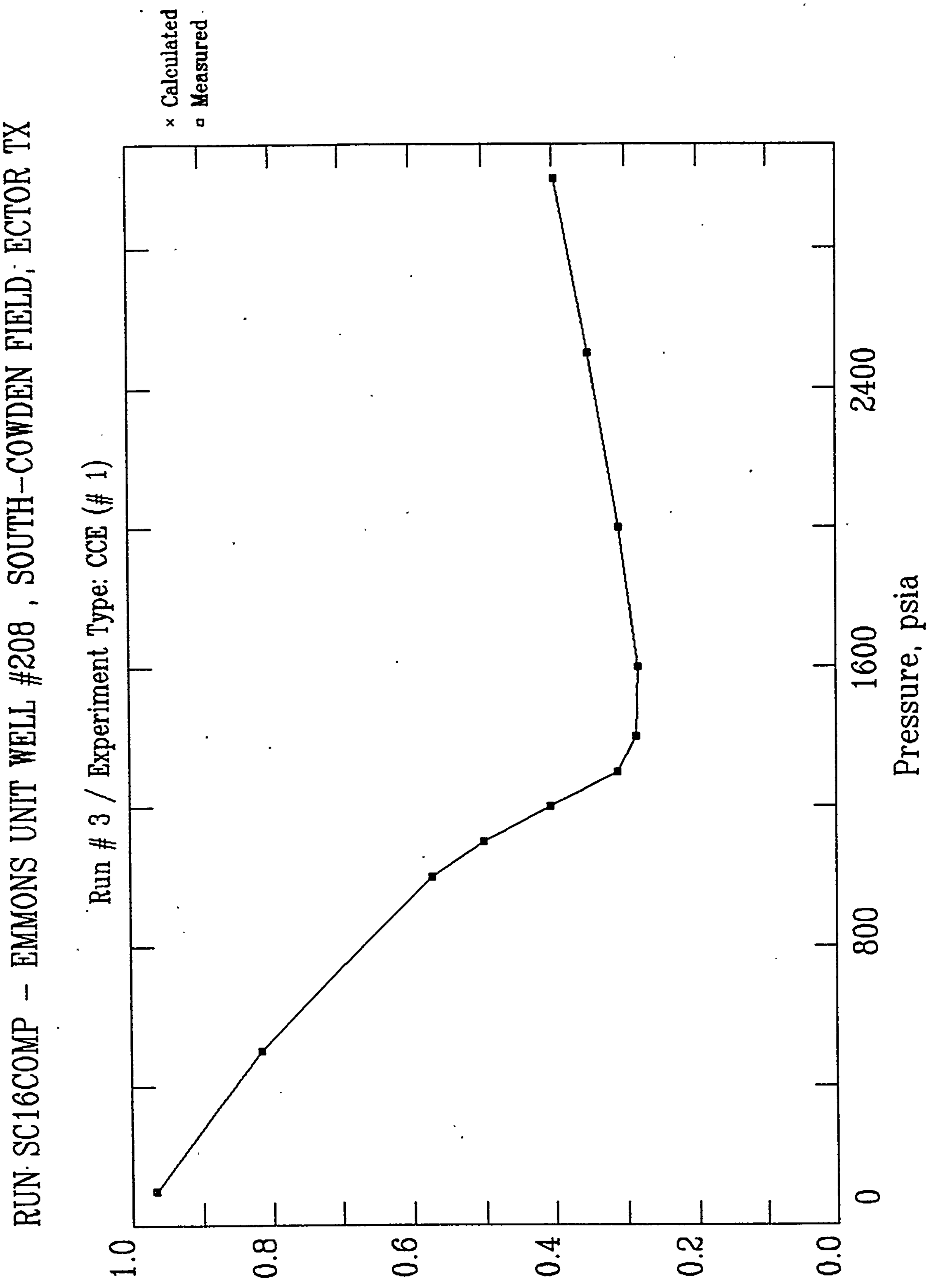

RUN SC16COMP – EMMONS UNIT WELL #208 , SOUTH-COWDEN FIELD, ECTOR TX
Run # 3 / Experiment Type: CCE (# 1)
× Calculated
▫ Measured
CO2 Injection Gas Z-factor
Pressure, psia
0
800
1600
2400
0.0
0.2
0.4
0.6
0.8
1.0

FIGURE 30

South Cowden Pressure vs. Composition

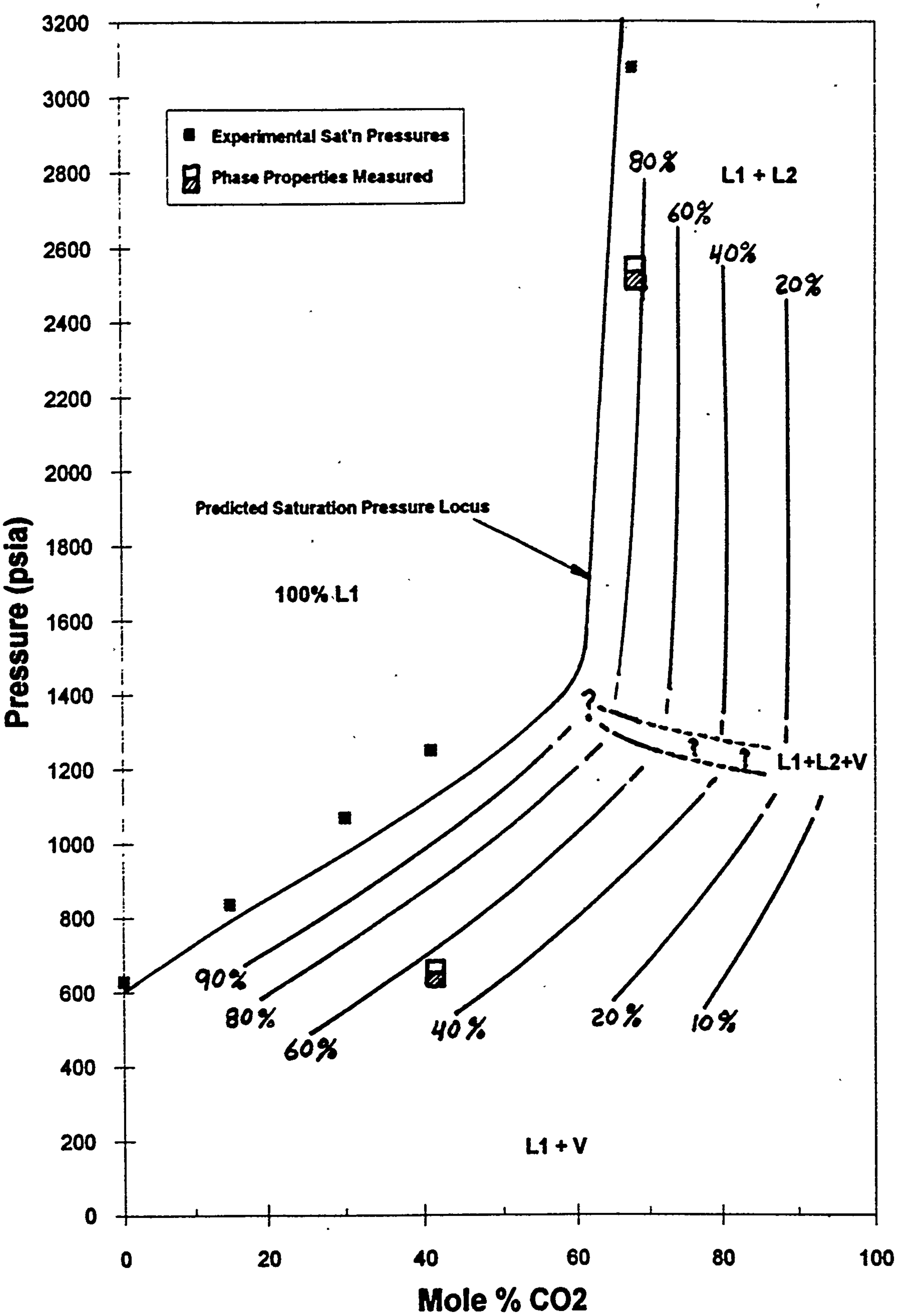
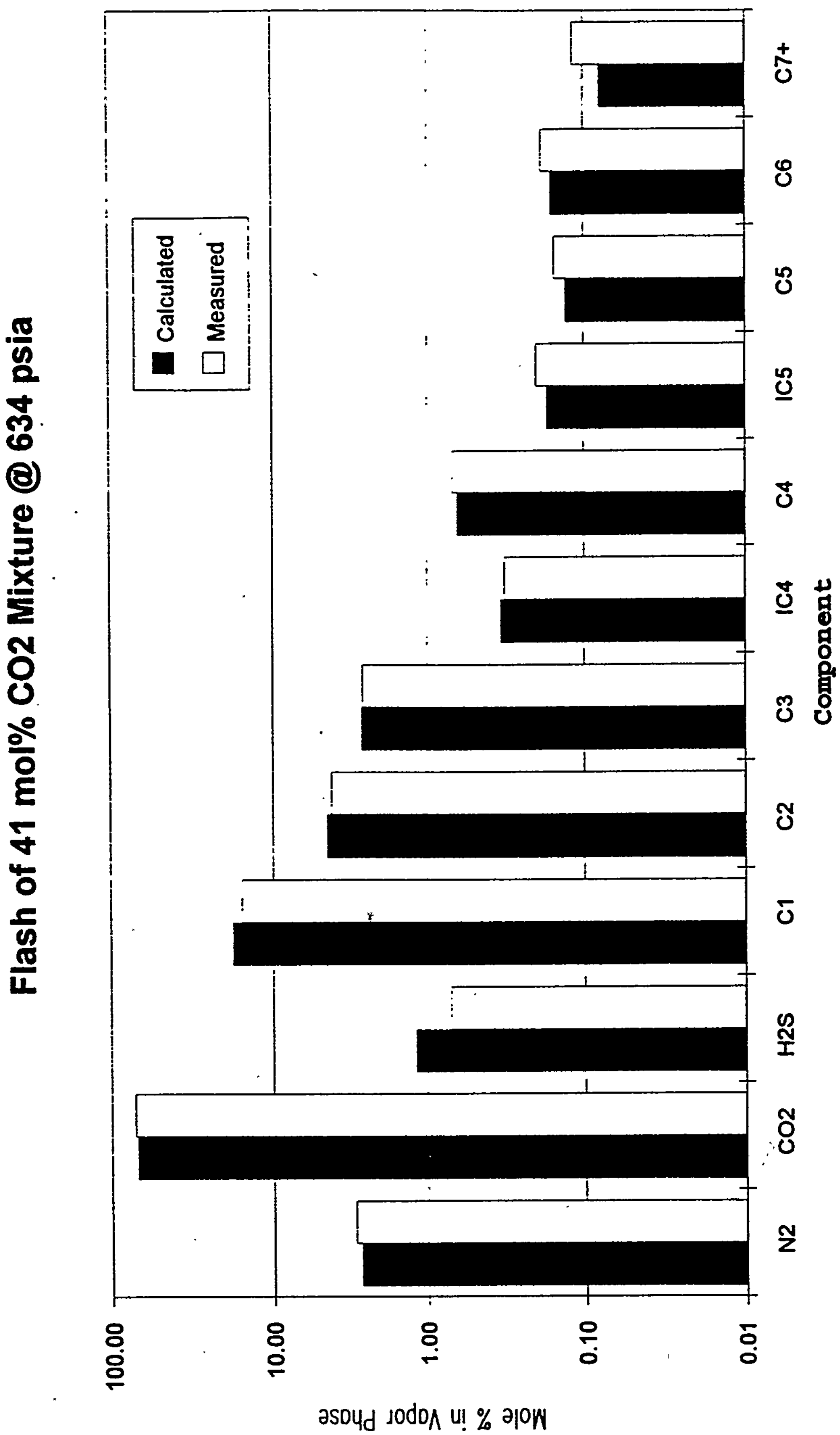
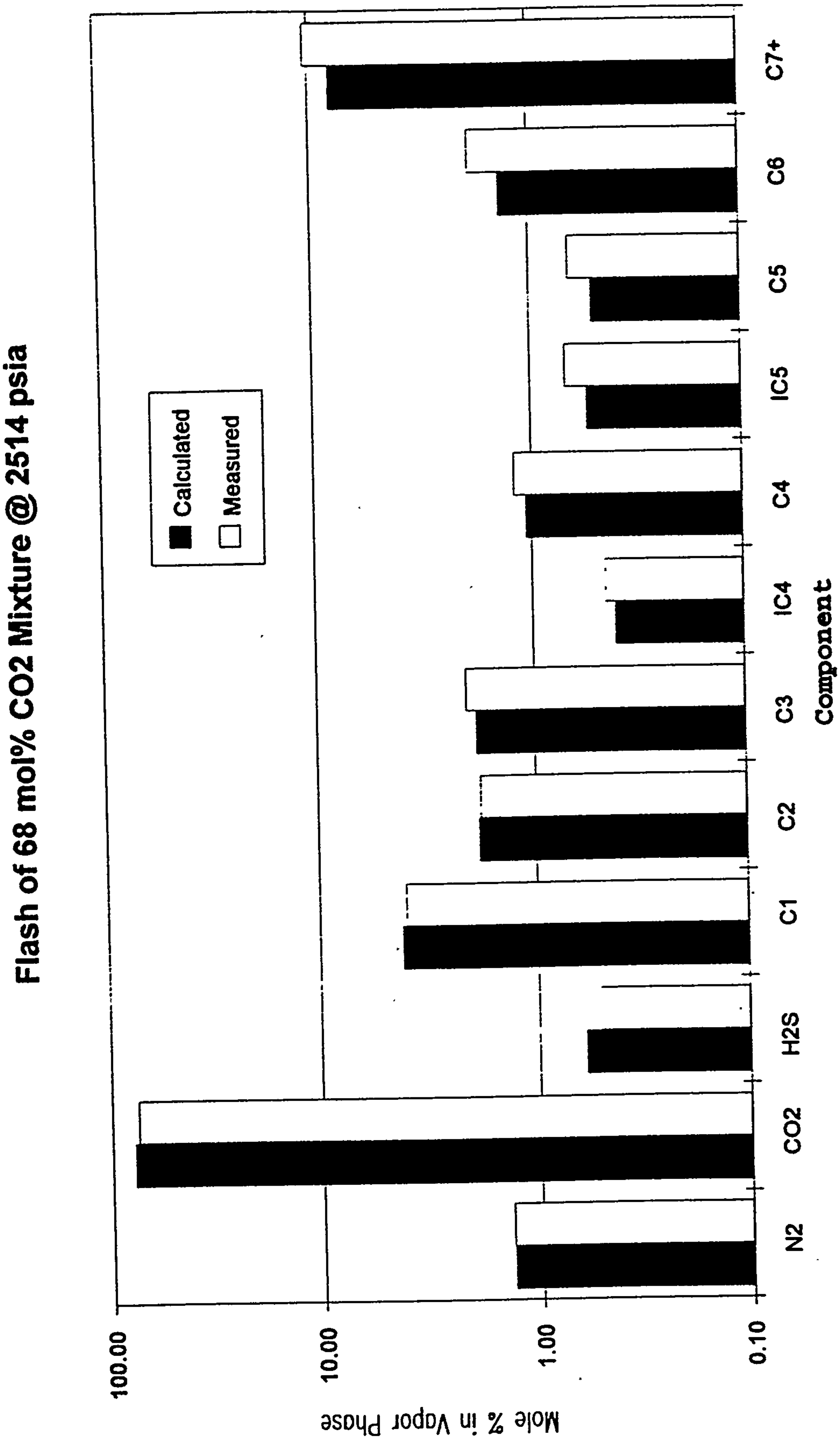


FIGURE 31



Flash of 41 mol% CO2 Mixture @ 634 psia
Calculated
Measured
Mole % in Vapor Phase
100.00
10.00
1.00
0.10
0.01
N2
CO2
H2S
C1
C2
C3
IC4
C4
IC5
C5
C6
C7+
Component

FIGURE 32



Flash of 68 mol% CO2 Mixture @ 2514 psia
Calculated
Measured
Mole % in Vapor Phase
100.00
10.00
1.00
0.10
N2
CO2
H2S
C1
C2
C3
IC4
C4
IC5
C5
C6
C7+
Component

FIGURE 33

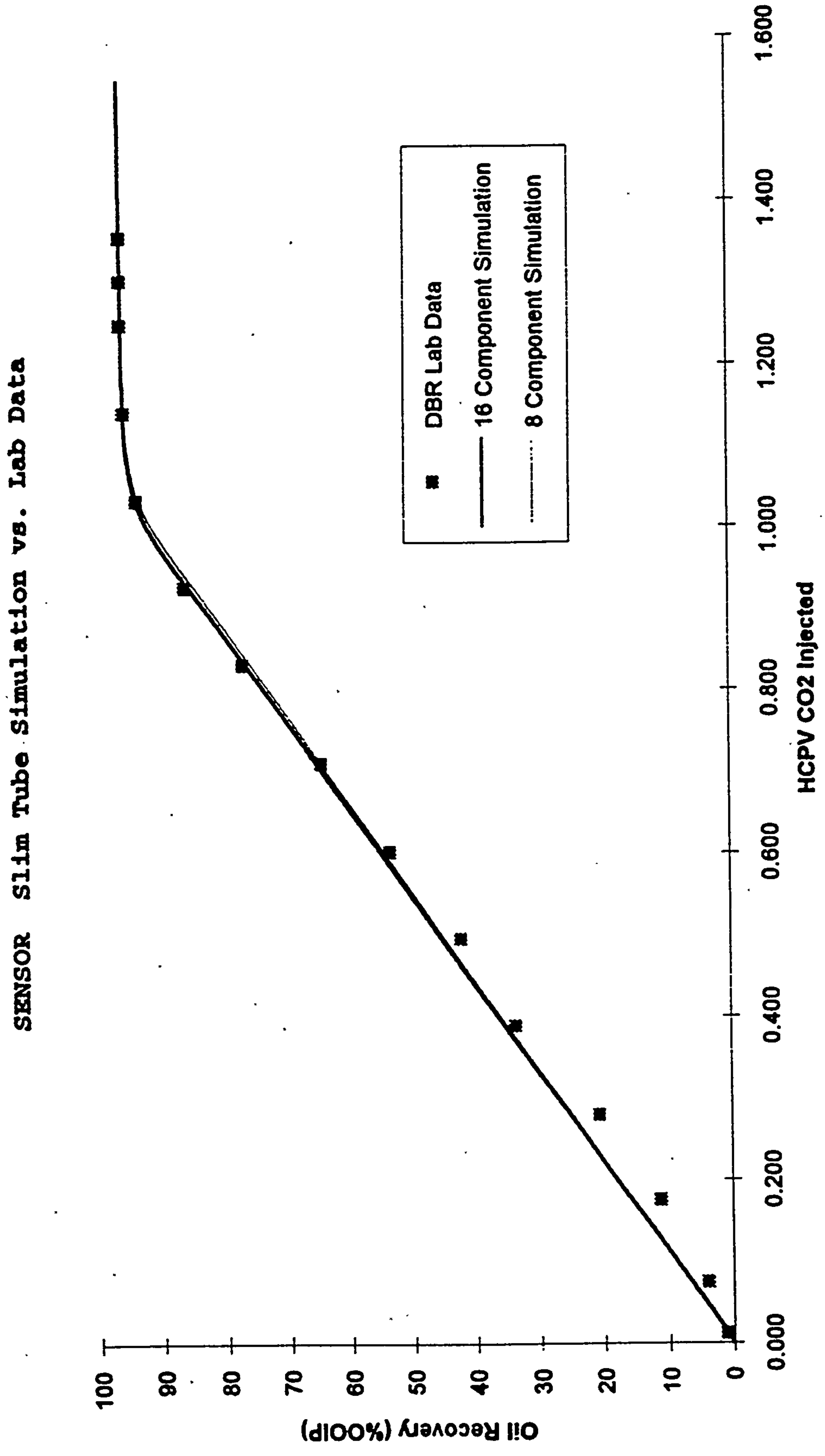

SENSOR Slim Tube Simulation vs. Lab Data
DBR Lab Data
16 Component Simulation
8 Component Simulation
Oil Recovery (%OOIP)
HCPV CO2 Injected
0
10
20
30
40
50
60
70
80
90
100
0.000
0.200
0.400
0.600
0.800
1.000
1.200
1.400
1.600

FIGURE 34

SENSOR Slim Tube Simulation vs. Lab Data

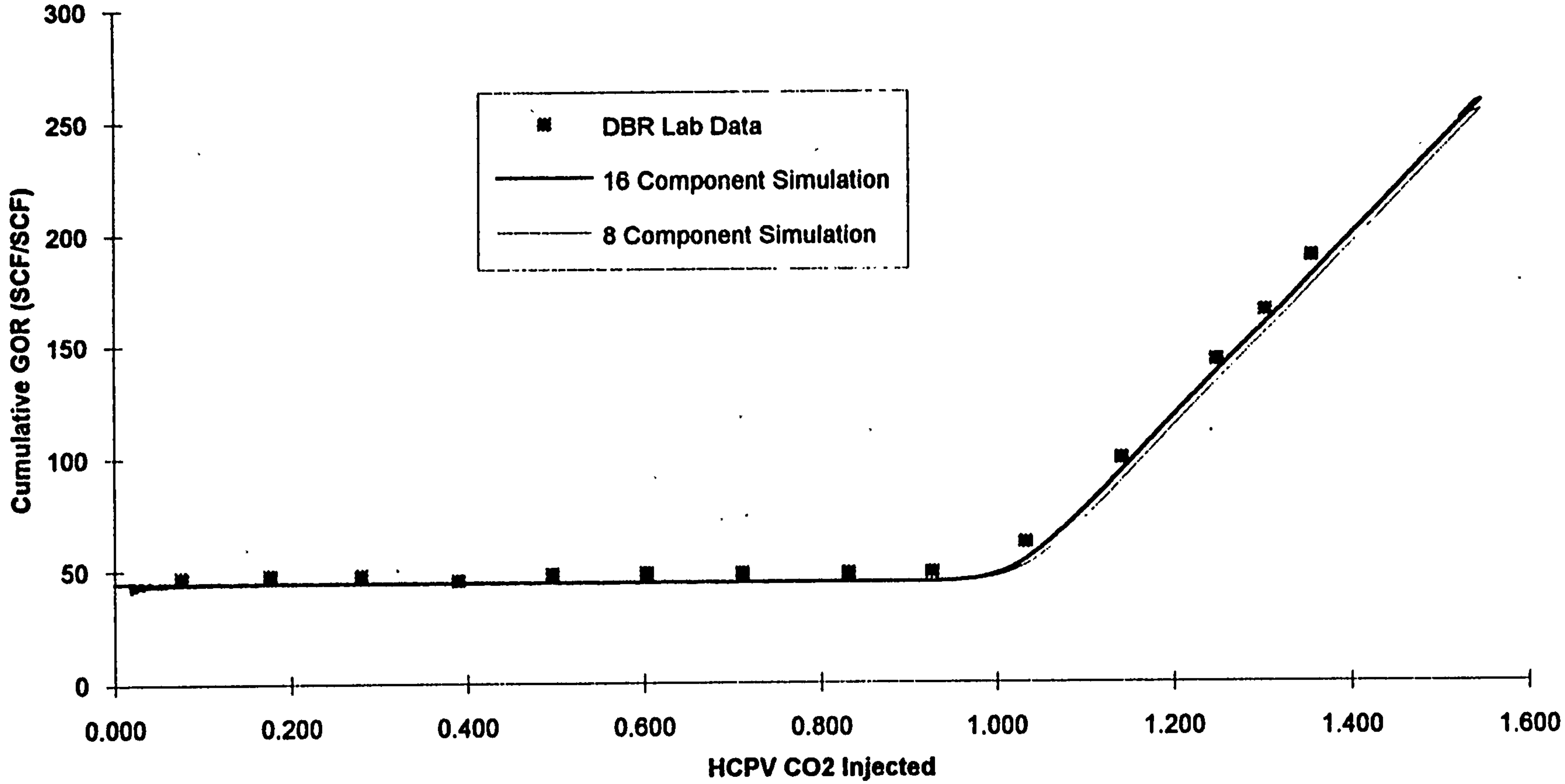


FIGURE 35

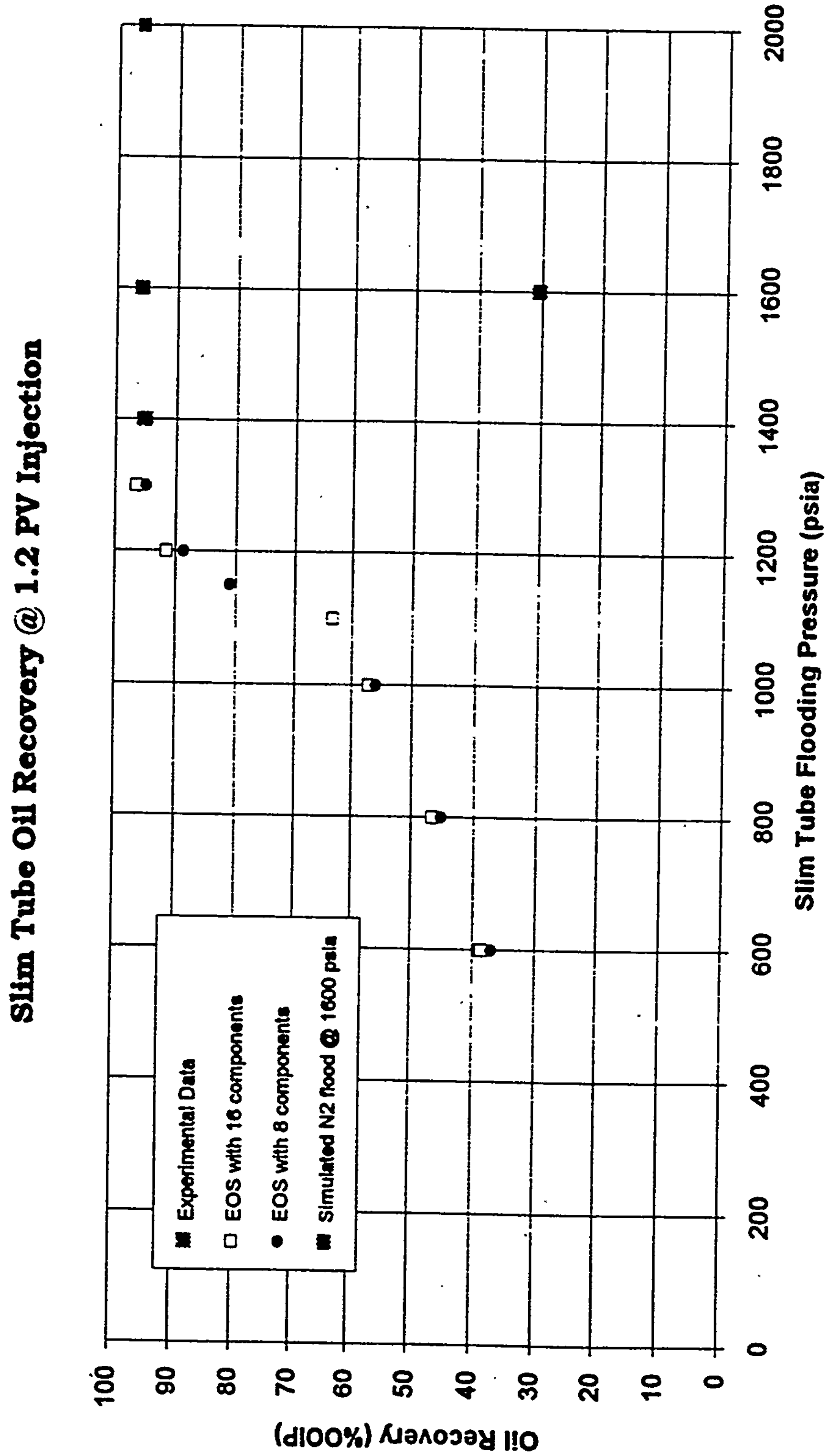
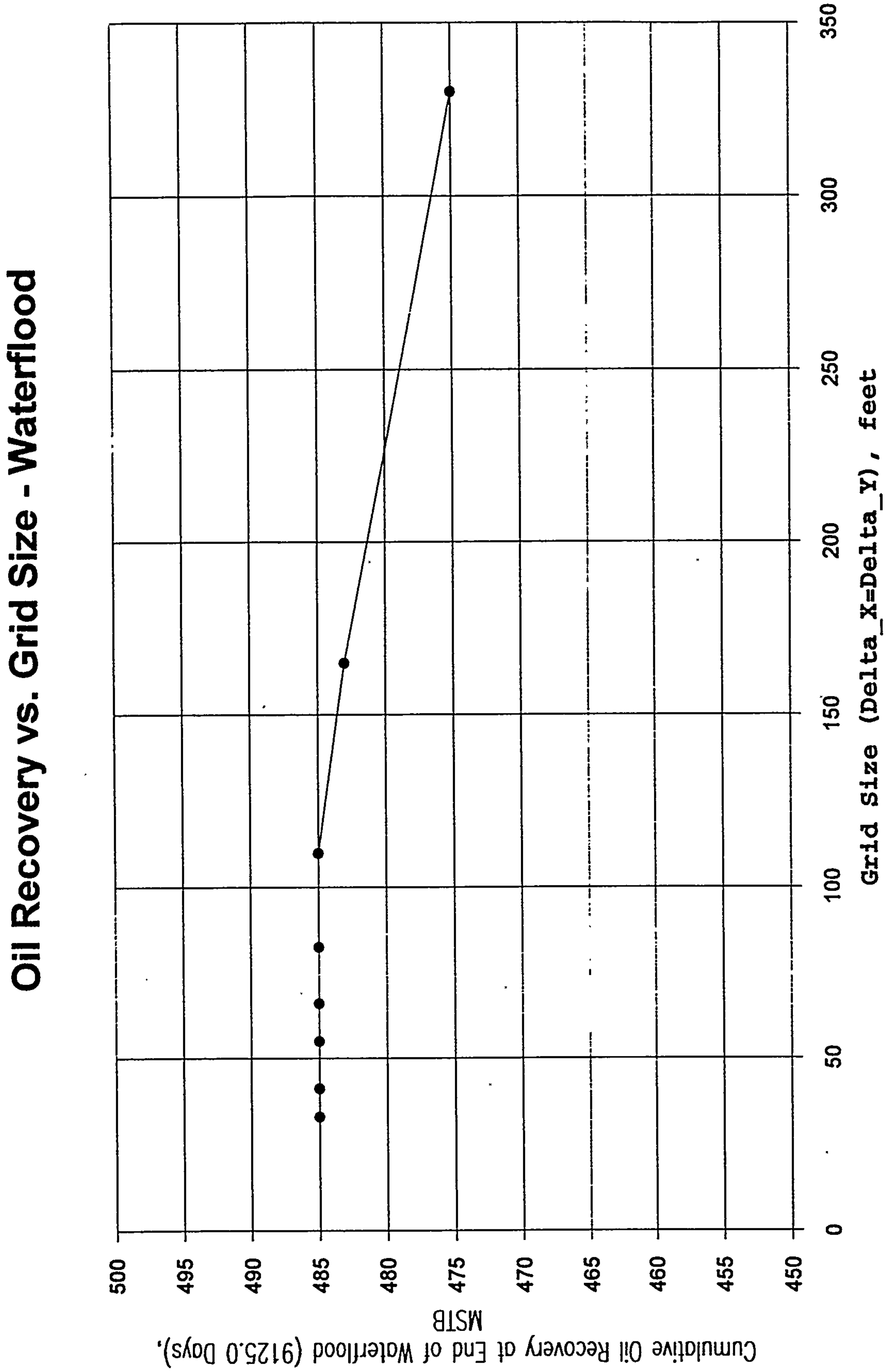

Slim Tube Oil Recovery @ 1.2 PV Injection
Experimental Data
EOS with 16 components
EOS with 8 components
Simulated N2 flood @ 1600 psia
Oil Recovery (%OOIP)
100
90
80
70
60
50
40
30
20
10
0
0
200
400
600
800
1000
1200
1400
1600
1800
2000
Slim Tube Flooding Pressure (psia)

FIGURE 36



Oil Recovery vs. Grid Size - Waterflood
Grid Size (Delta_X=Delta_Y), feet
Cumulative Oil Recovery at End of Waterflood (9125.0 Days), MSTB
0
50
100
150
200
250
300
350
500
495
490
485
480
475
470
465
460
455
450

FIGURE 37

SENSOR vs. P4422

Cumulative Oil vs. Time

Fivespot Pattern Element

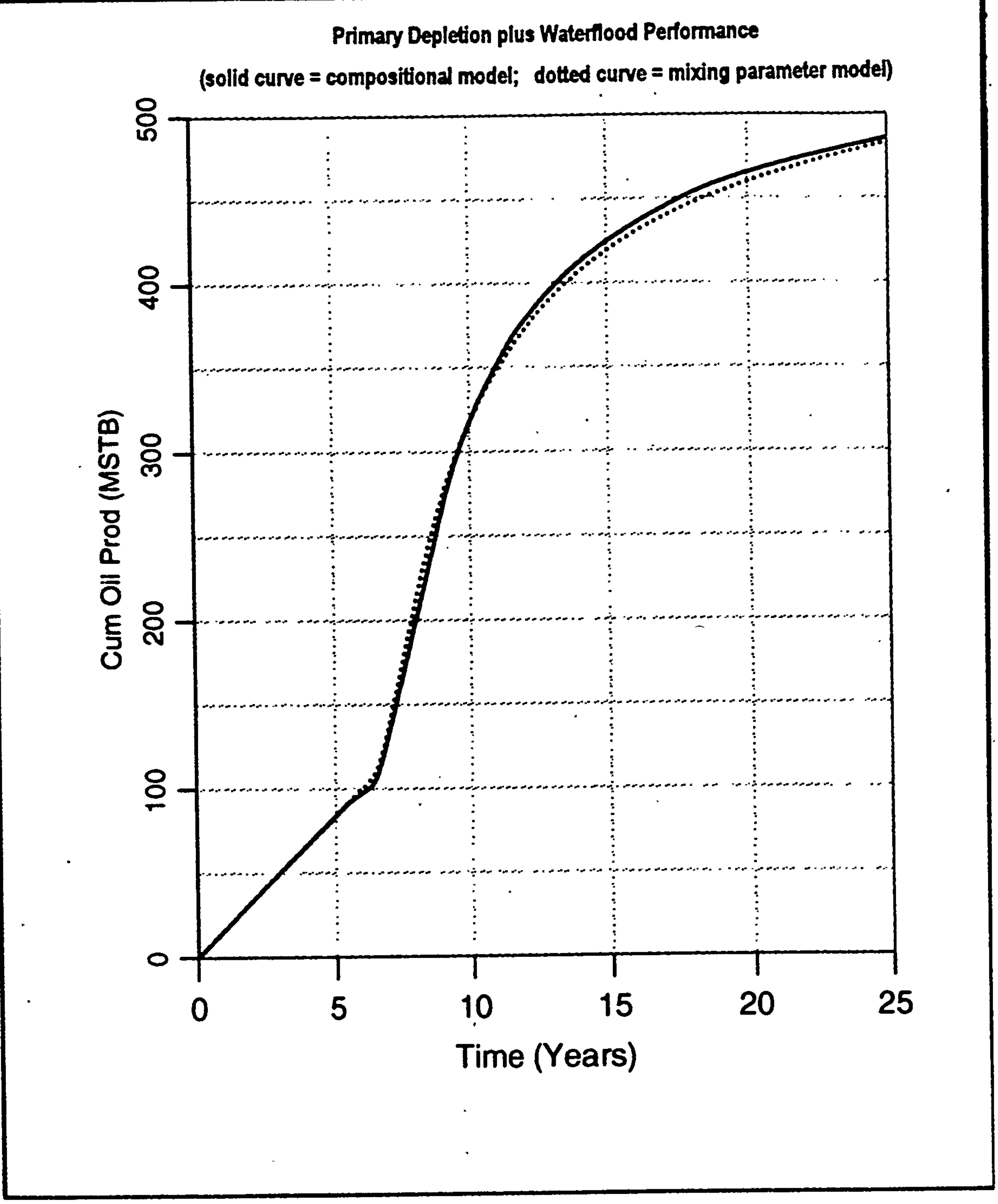


FIGURE 38

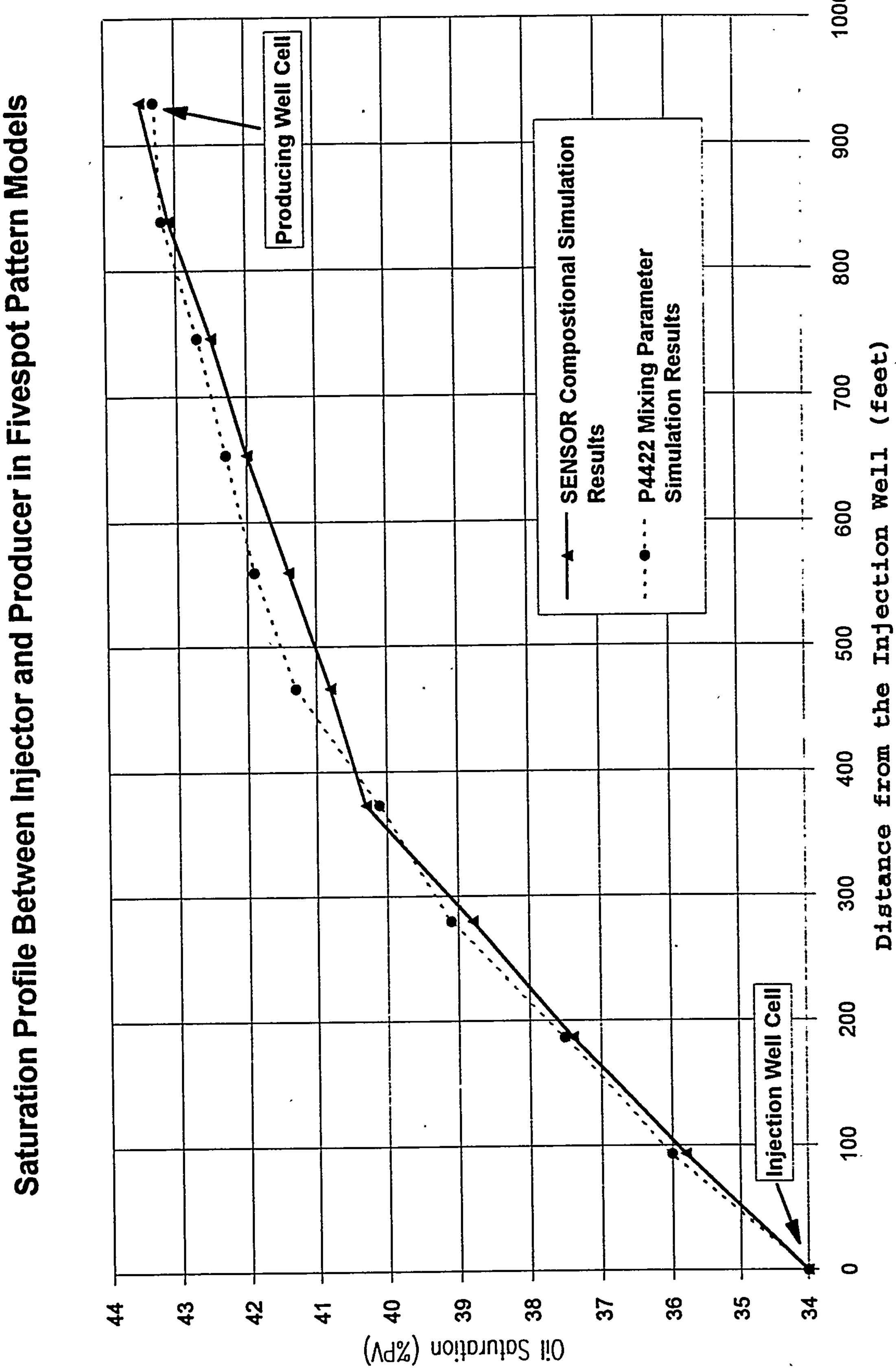
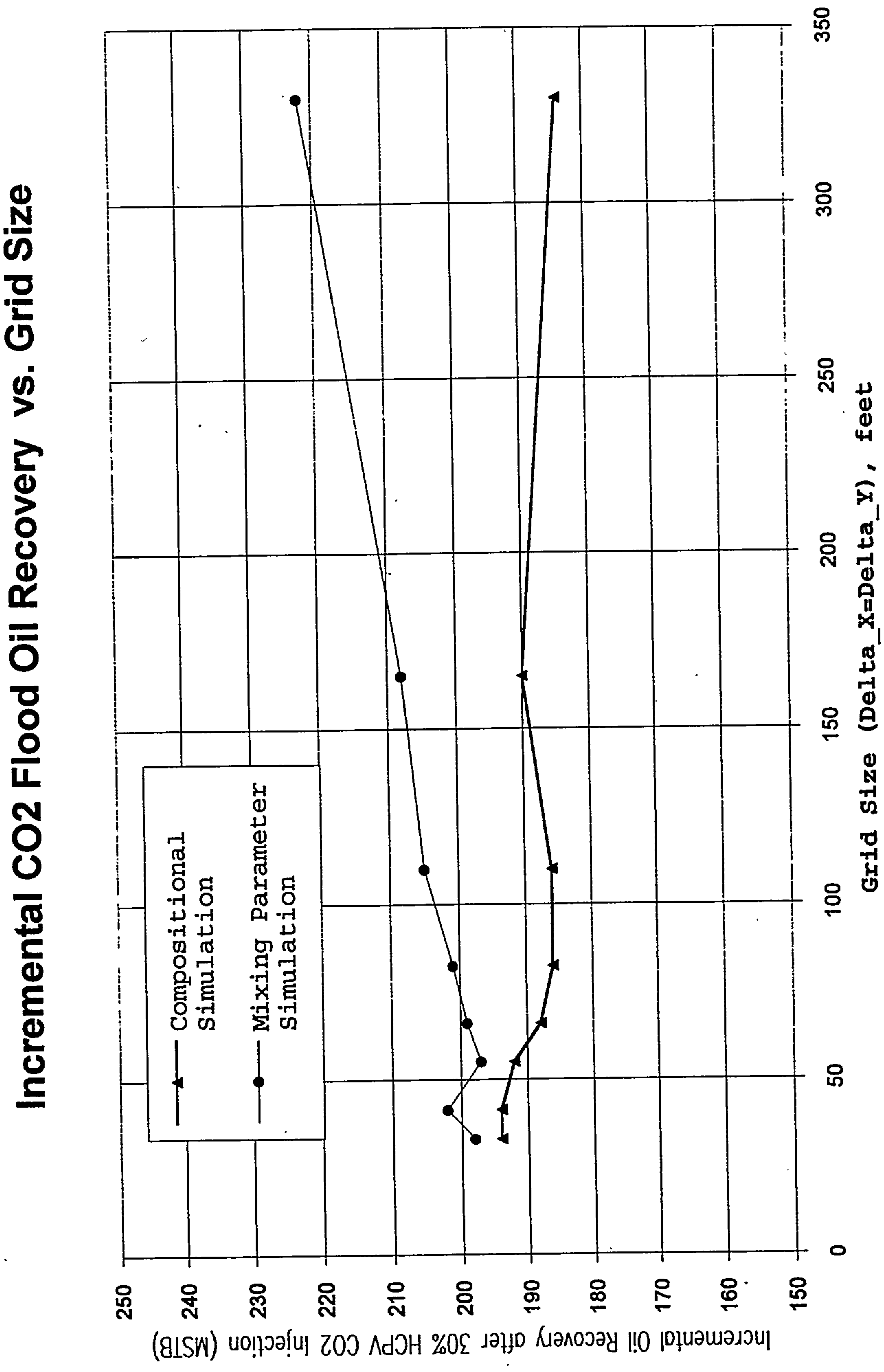

Saturation Profile Between Injector and Producer in Fivespot Pattern Models
Producing Well Cell
Injection Well Cell
SENSOR Compostional Simulation Results
P4422 Mixing Parameter Simulation Results
Oil Saturation (%PV)
44
43
42
41
40
39
38
37
36
35
34
Distance from the Injection Well (feet)
0
100
200
300
400
500
600
700
800
900
1000

FIGURE 39



Incremental CO2 Flood Oil Recovery vs. Grid Size
Compositional Simulation
Mixing Parameter Simulation
Grid Size (Delta_X=Delta_Y), feet
Incremental Oil Recovery after 30% HCPV CO2 Injection (MSTB)
0
50
100
150
200
250
300
350
150
160
170
180
190
200
210
220
230
240
250

FIGURE 40

CO2 Flood Oil Recovery vs. Layer Thickness

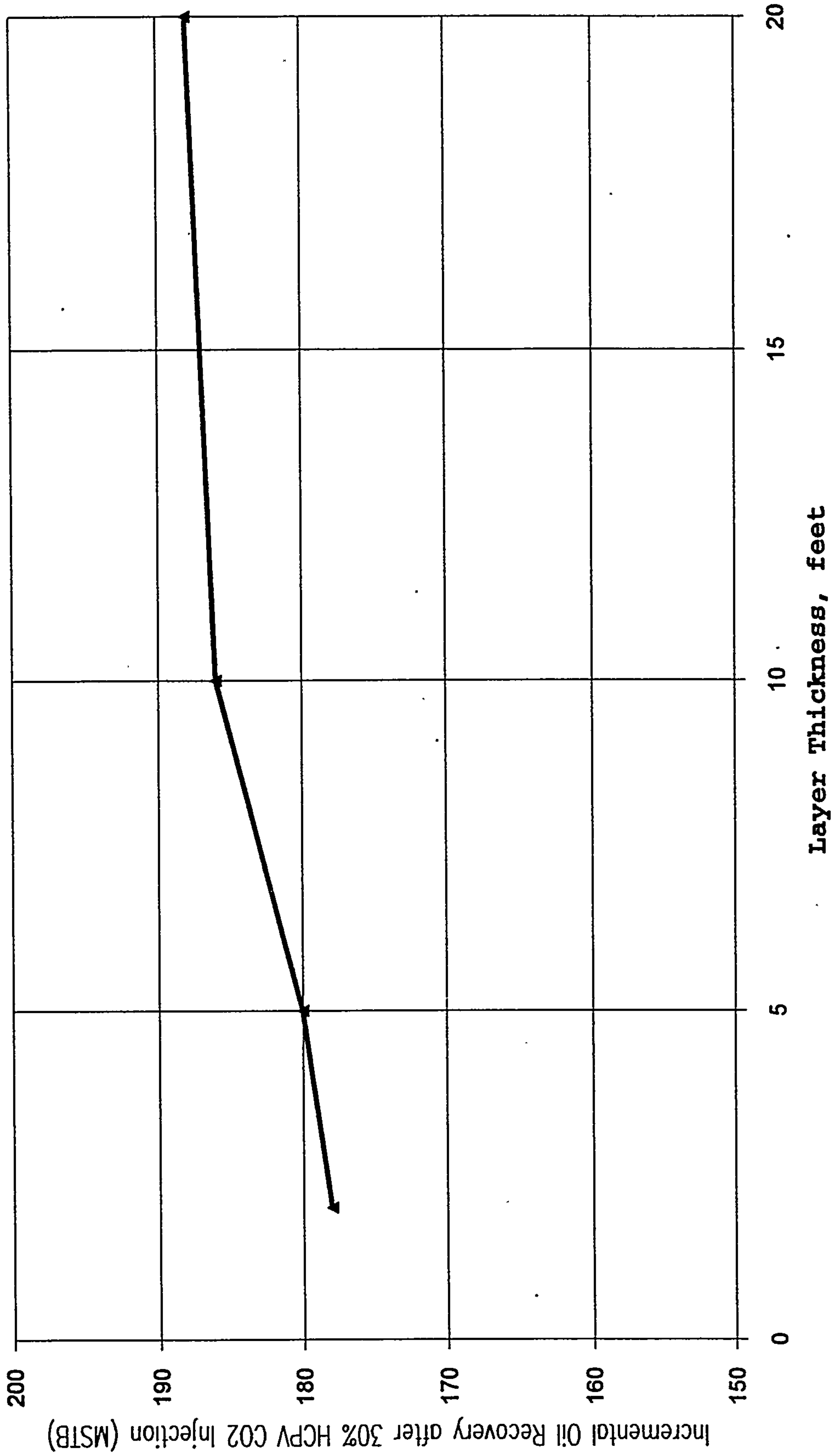


FIGURE 41

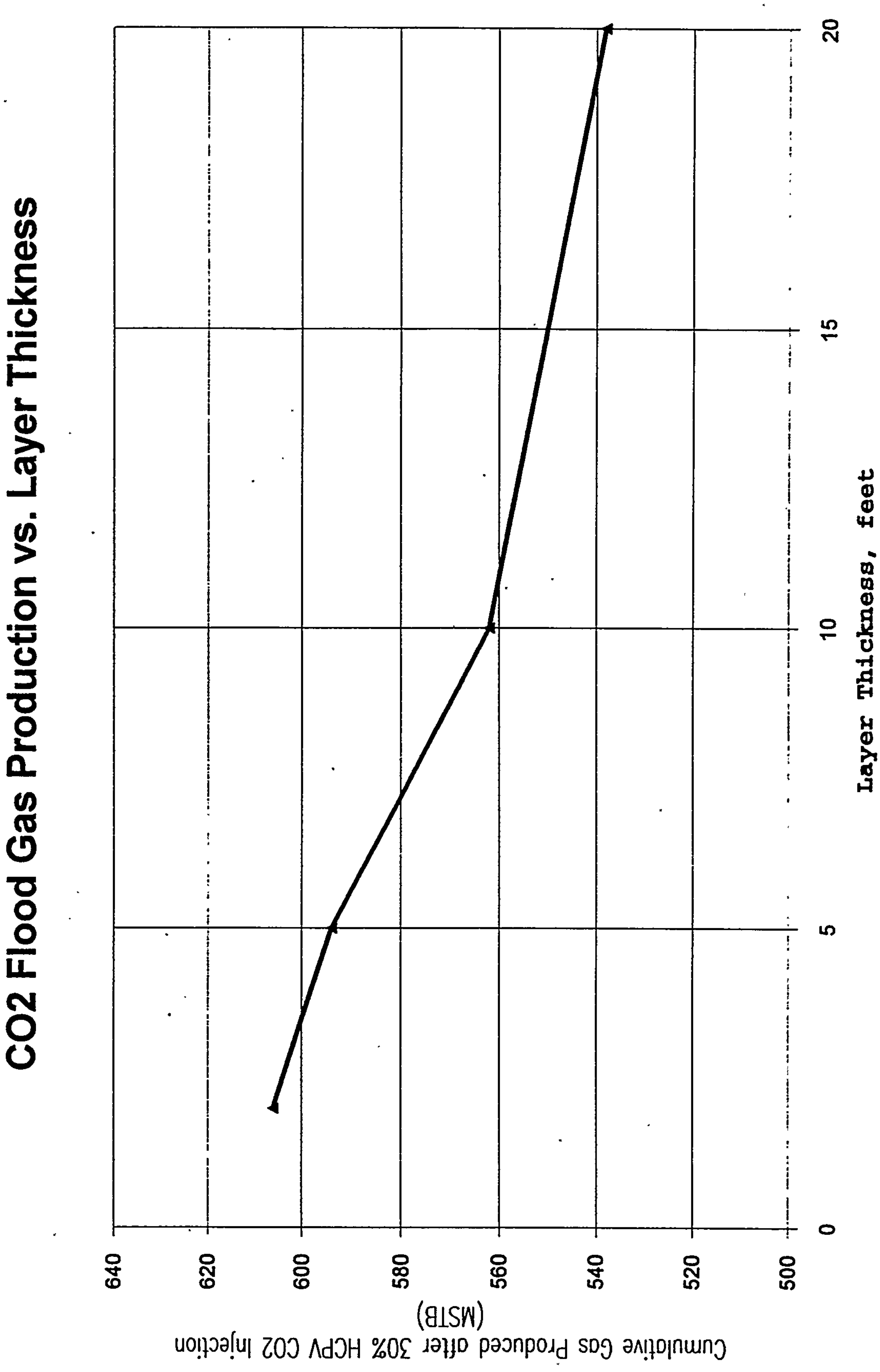

CO2 Flood Gas Production vs. Layer Thickness
Layer Thickness, feet
0
5
10
15
20
Cumulative Gas Produced after 30% HCPV CO2 Injection (MSTB)
640
620
600
580
560
540
520
500

FIGURE 42

Porosity distribution along the long axis of a 2.54 cm diameter x 6.2 cm long South Cowden core plug

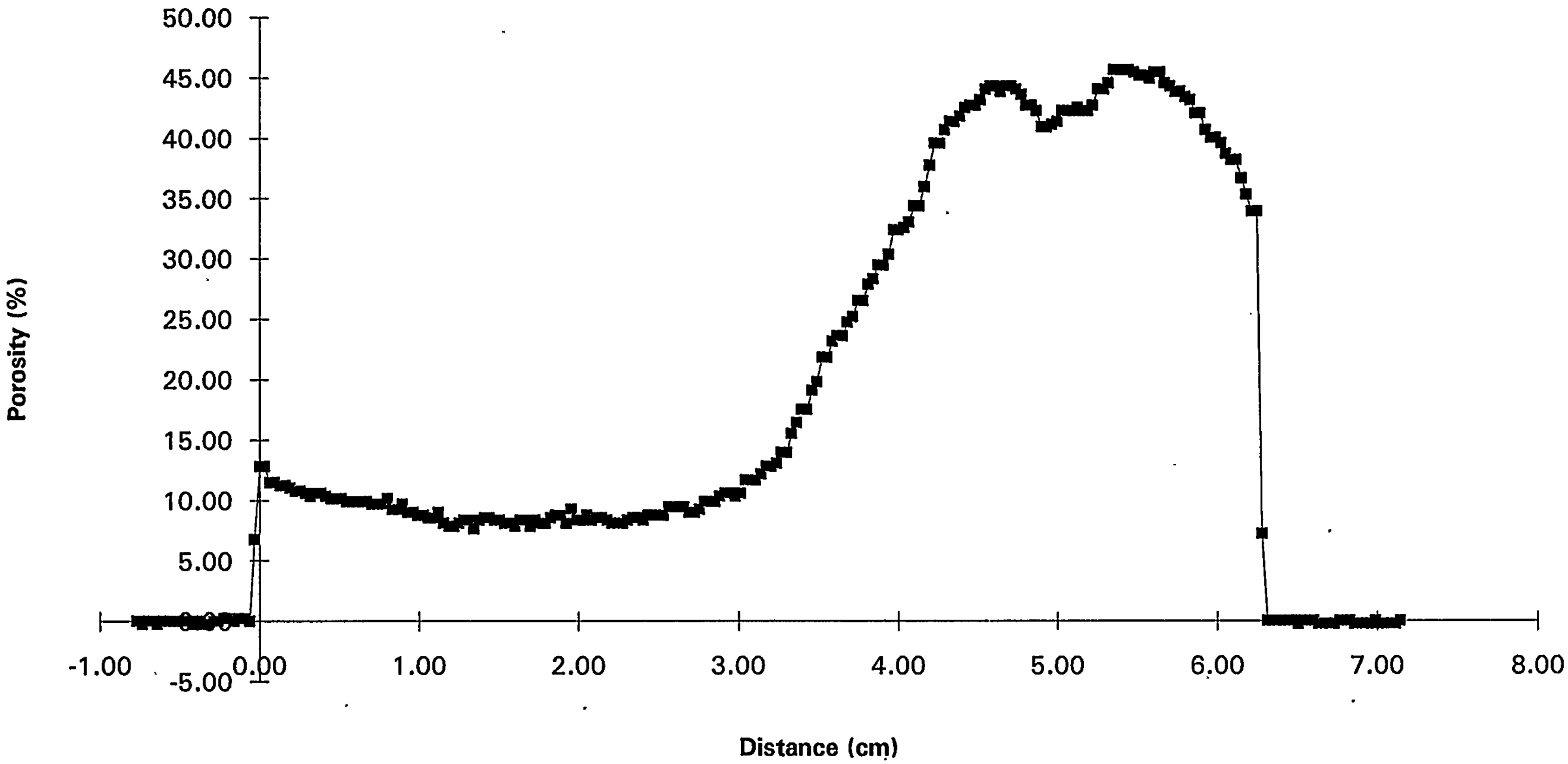
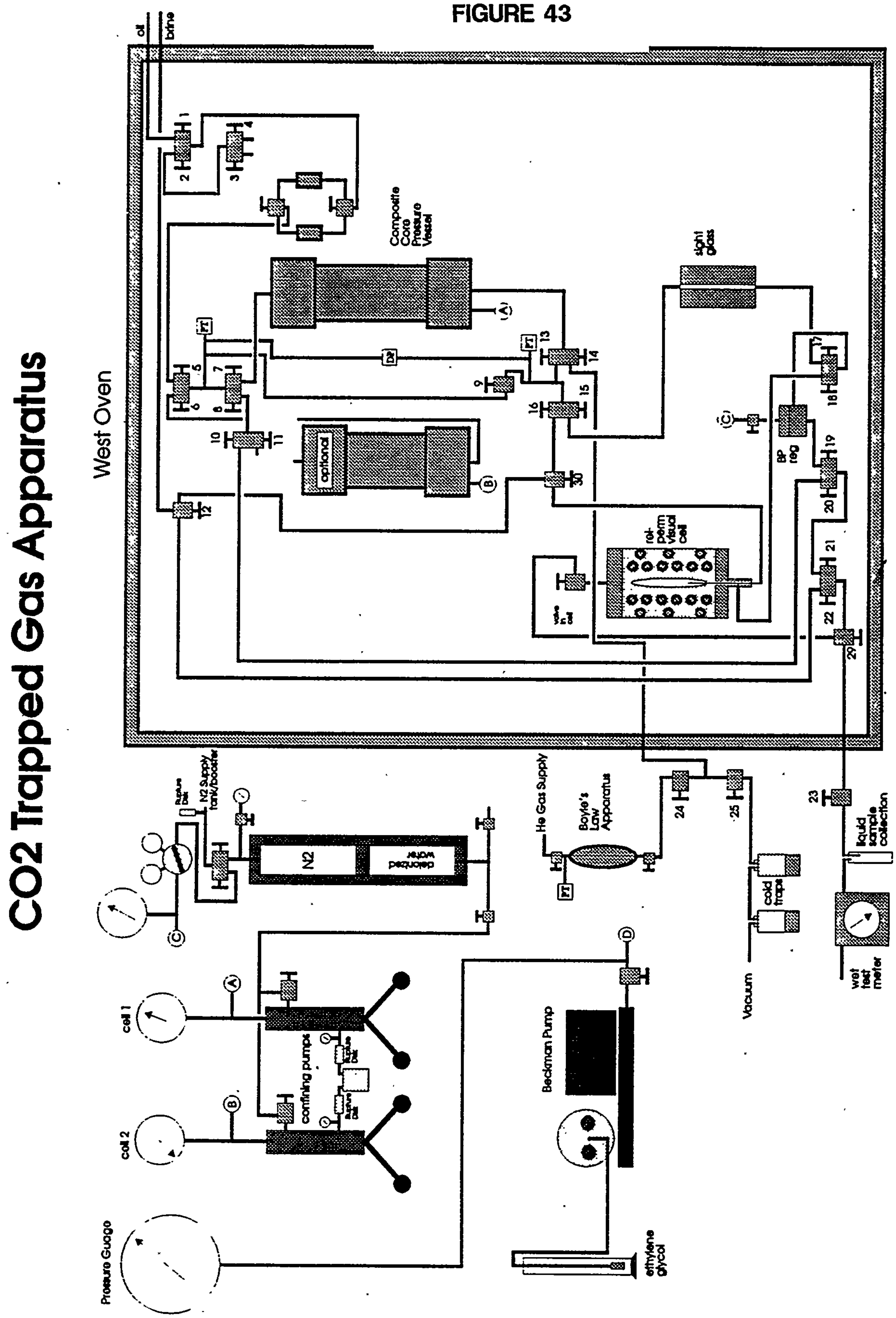


FIGURE 43



CO2 Trapped Gas Apparatus
West Oven
oil
brine
Composite Core Pressure Vessel
sight glass
optional
rel-perm visual cell
BP reg
N2 Supply tank/booster
N2
deionized water
He Gas Supply
Boyle's Law Apparatus
cold traps
Vacuum
liquid sample collection
wet test meter
cell 1
cell 2
confining pumps
Beckman Pump
Pressure Guage
ethylene glycol

FIGURE 44

CO2 Trapped Gas Apparatus

East Oven

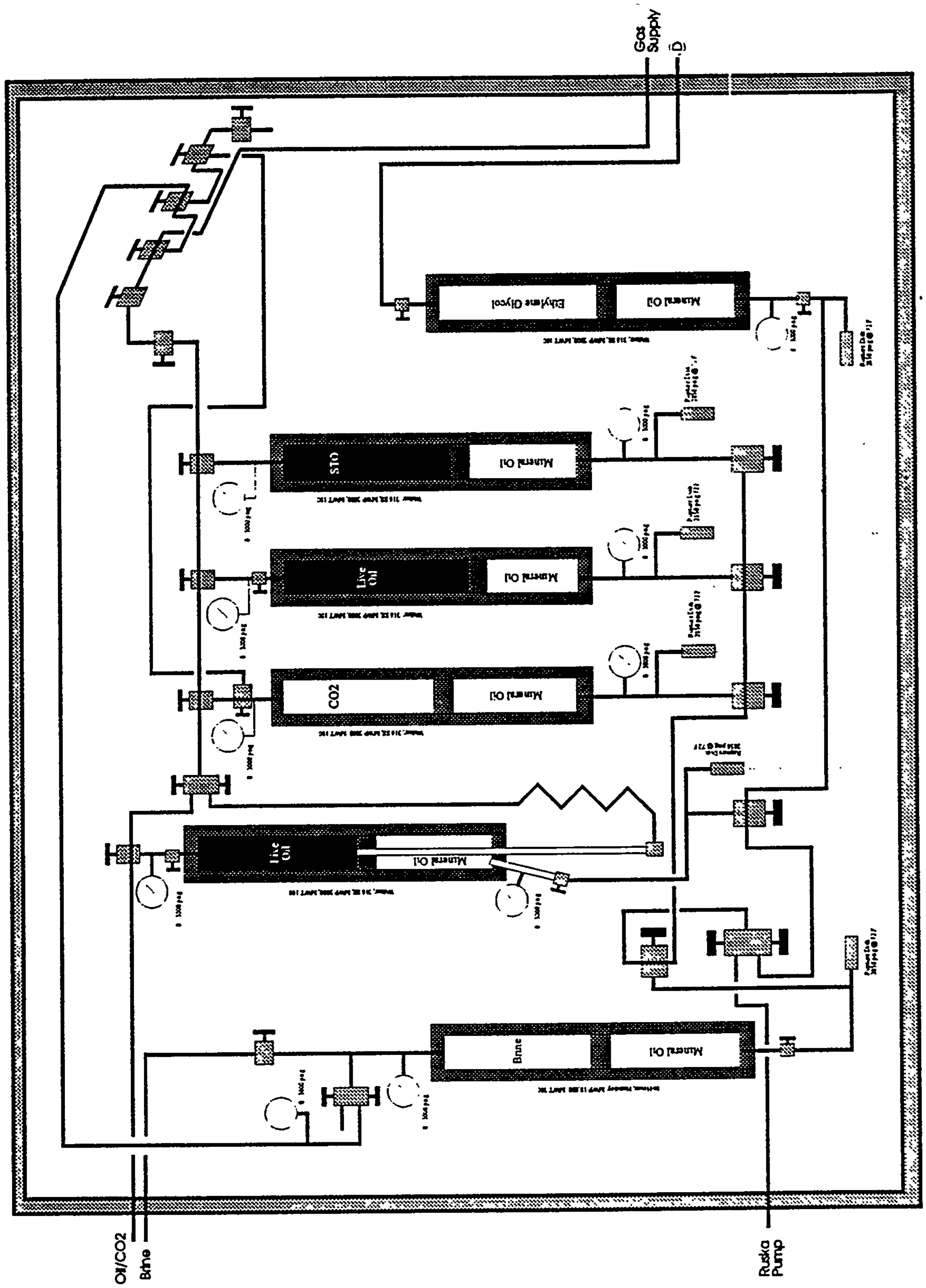
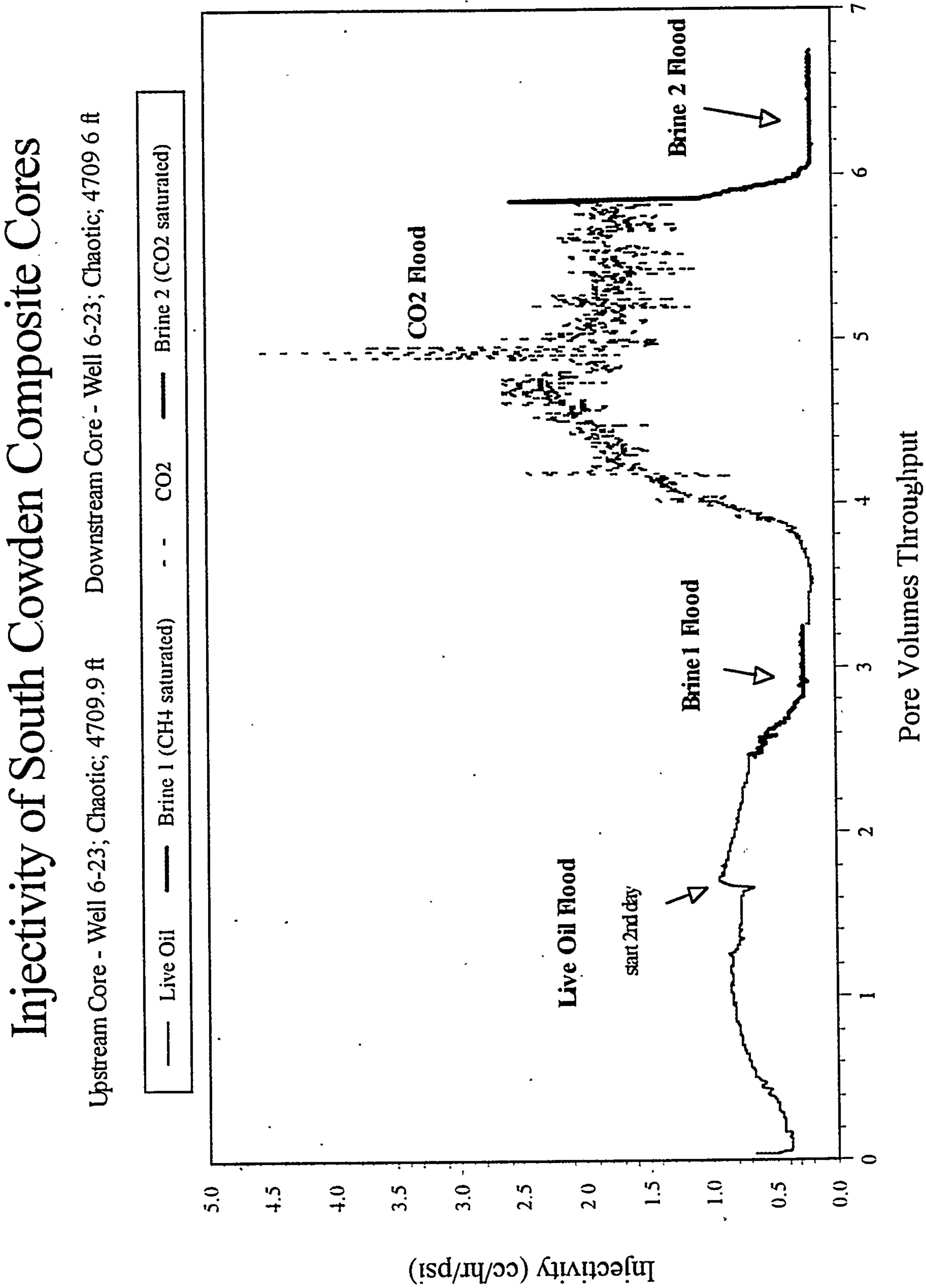
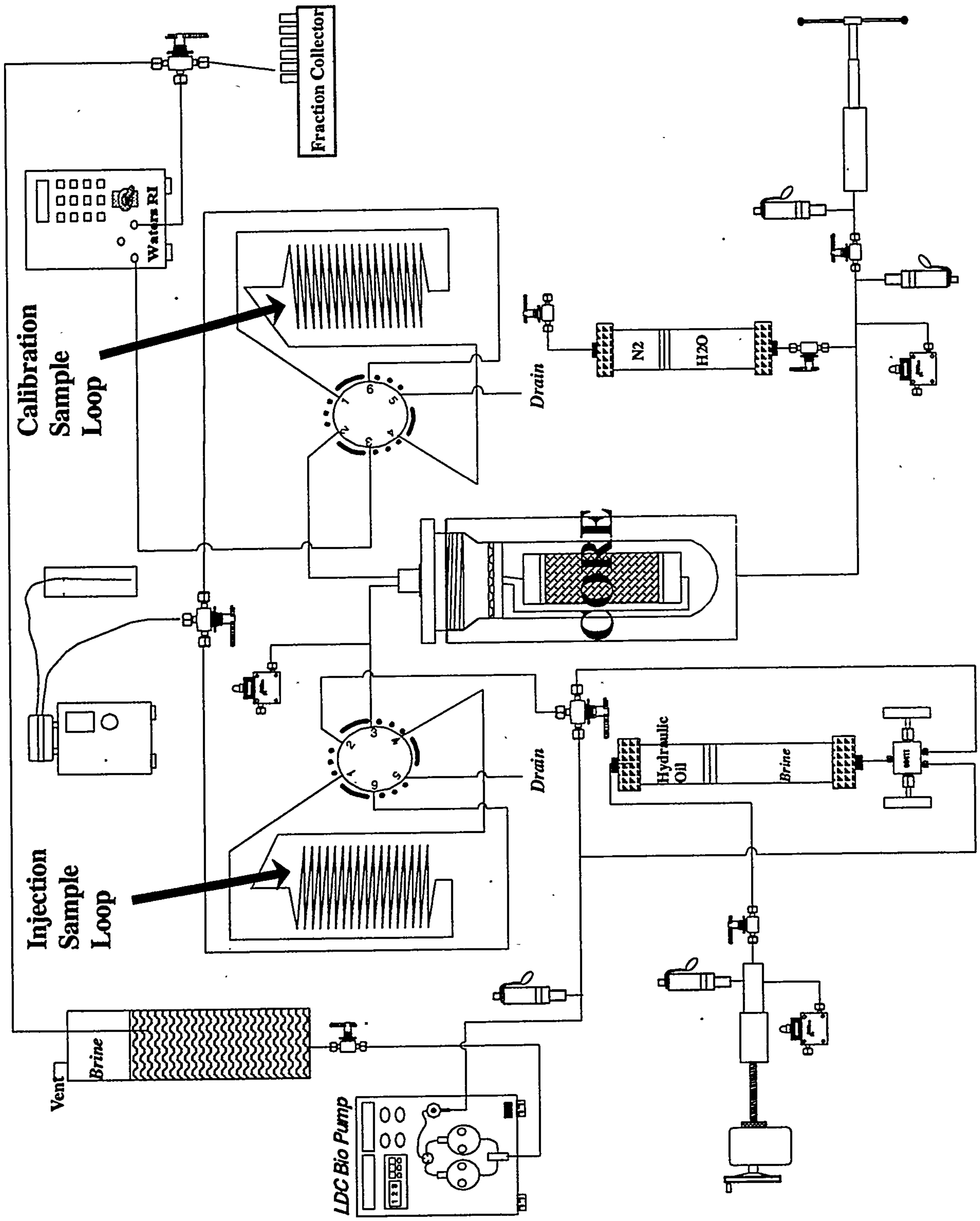


FIGURE 45



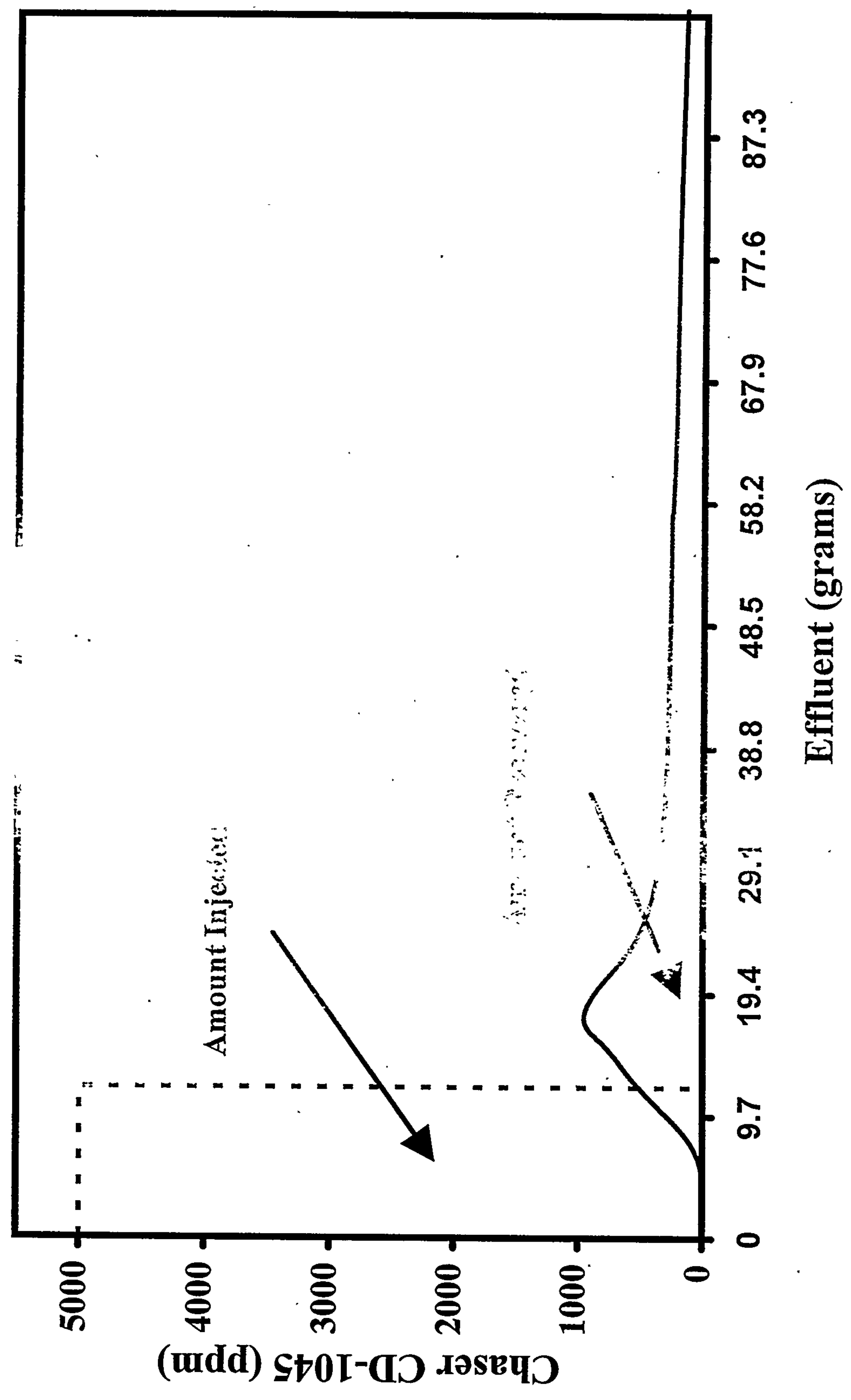
Injectivity of South Cowden Composite Cores
Upstream Core - Well 6-23; Chaotic; 4709.9 ft
Downstream Core - Well 6-23; Chaotic; 4709 6 ft
Live Oil
Brine 1 (CH4 saturated)
CO2
Brine 2 (CO2 saturated)
Live Oil Flood
start 2nd day
Brine 1 Flood
CO2 Flood
Brine 2 Flood
Injectivity (cc/hr/psi)
Pore Volumes Throughput
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5.0
0
1
2
3
4
5
6
7

FIGURE 46



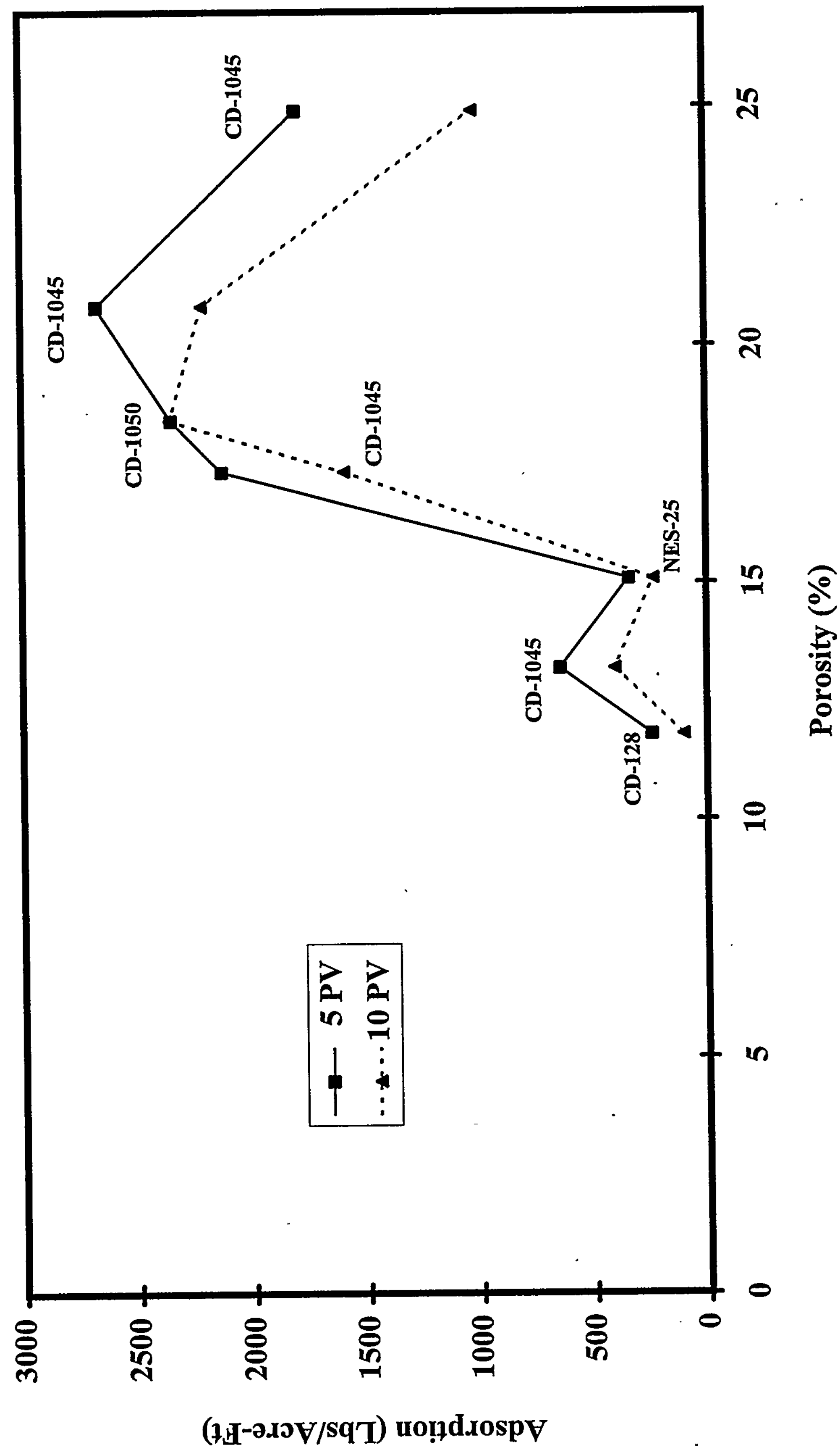
Schematic Diagram for Adsorption Setup

FIGURE 47



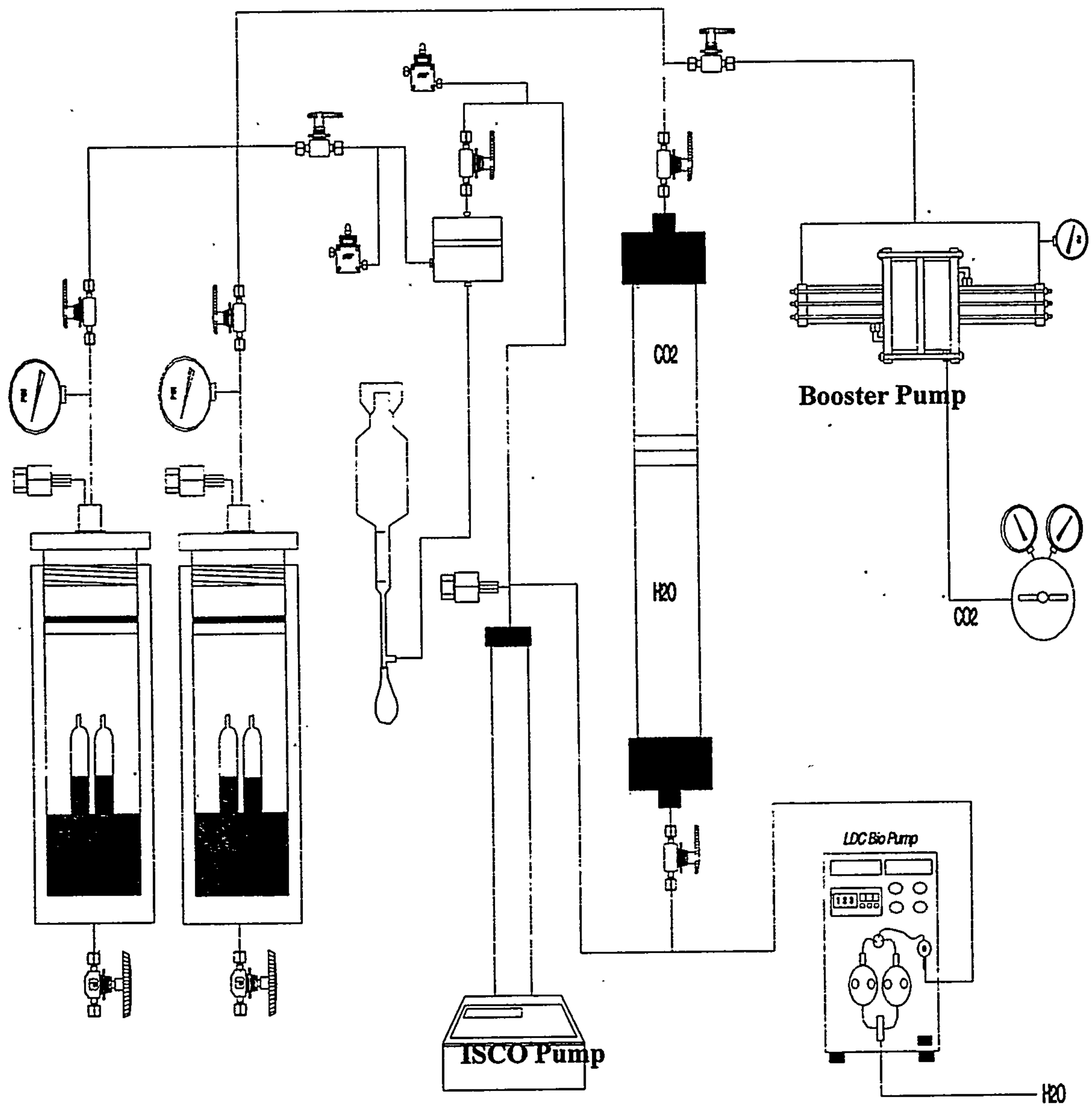
Adsorption of Chaser CD-1045 in South Cowden Field Core at 98 F

FIGURE 48



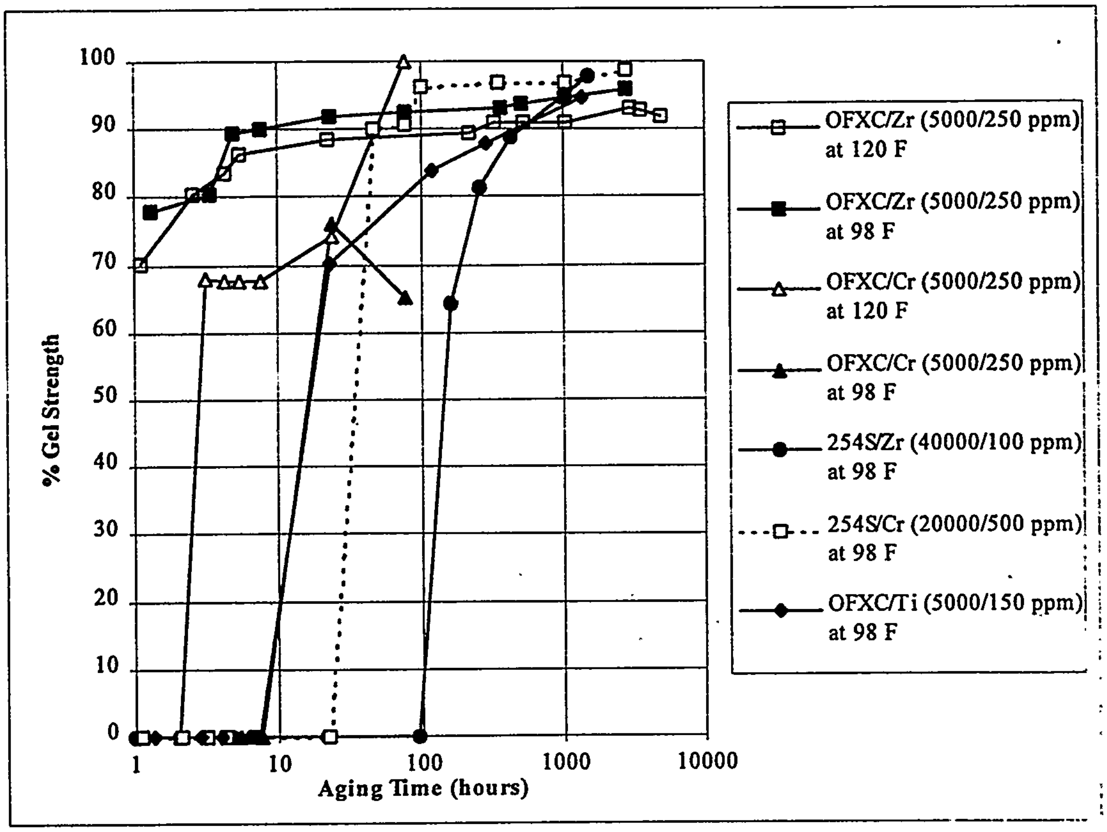
Dependence of Adsorption on Porosity

FIGURE 49



High Pressure Gel Stability Test Apparatus

FIGURE 50



Gel Strength as a Function of Aging Time for Various Polymer/Cross-linker Systems at different Concentrations and Temperatures.

Relative Amplitude Seismic Section

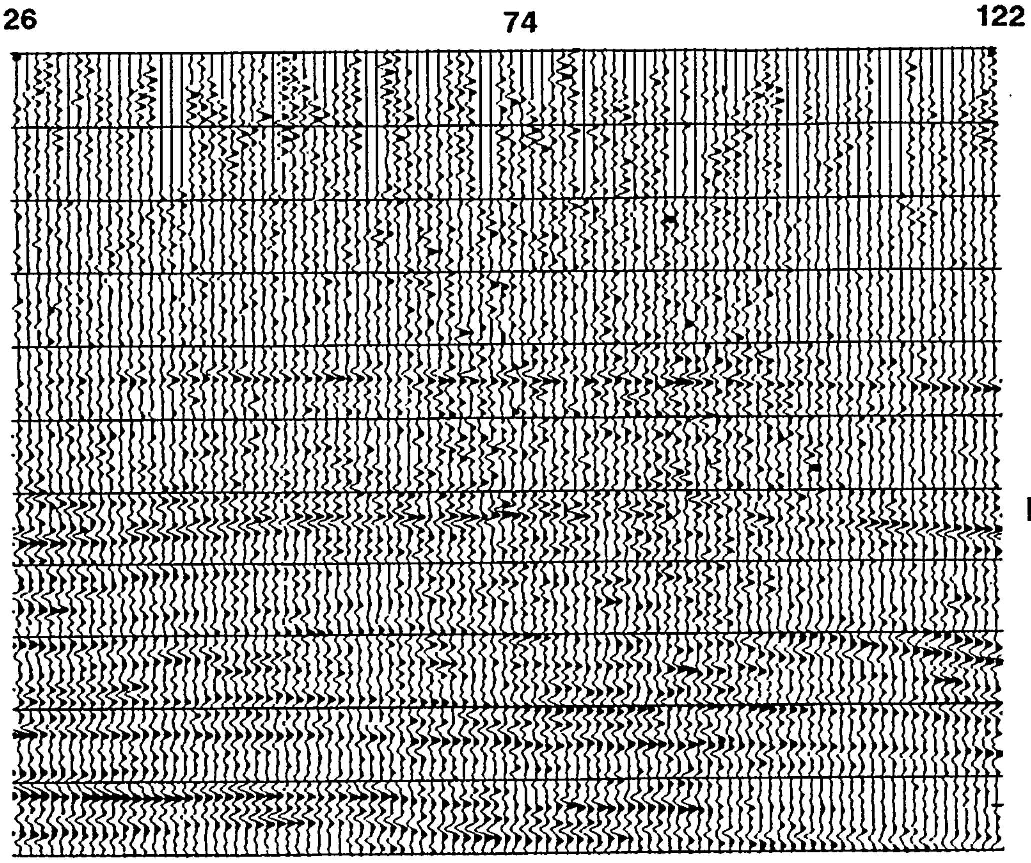


FIGURE 51A

Trace Mixed Seismic Section

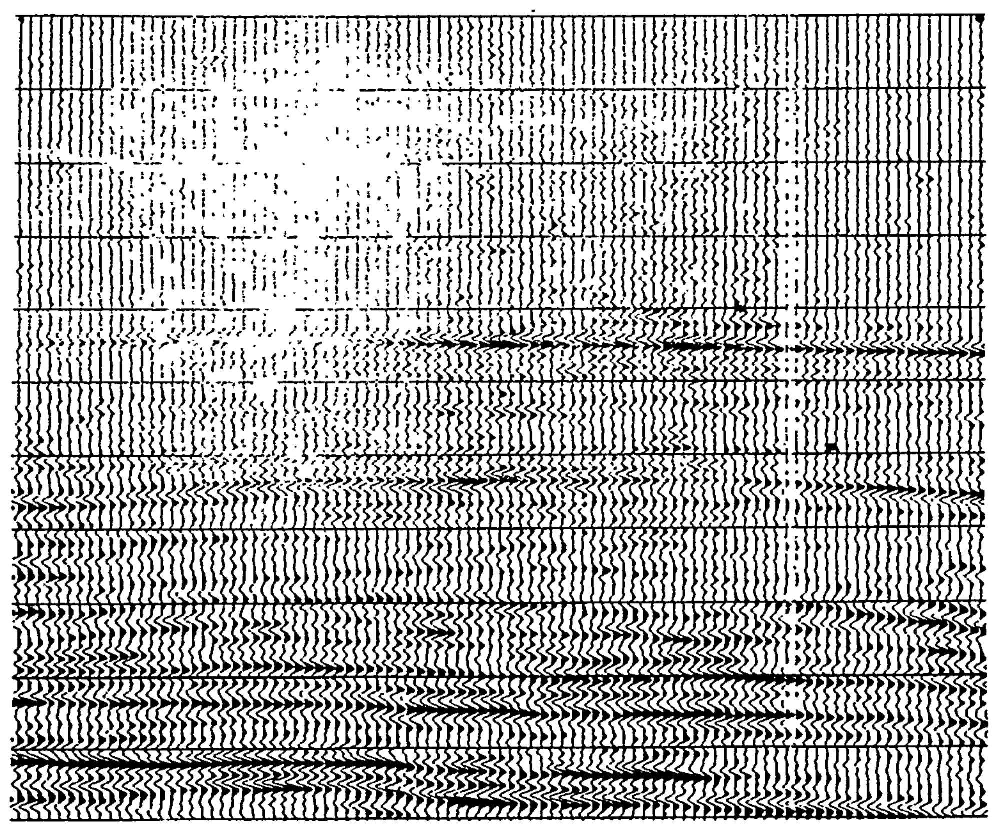


FIGURE 51B

WELL EMM215

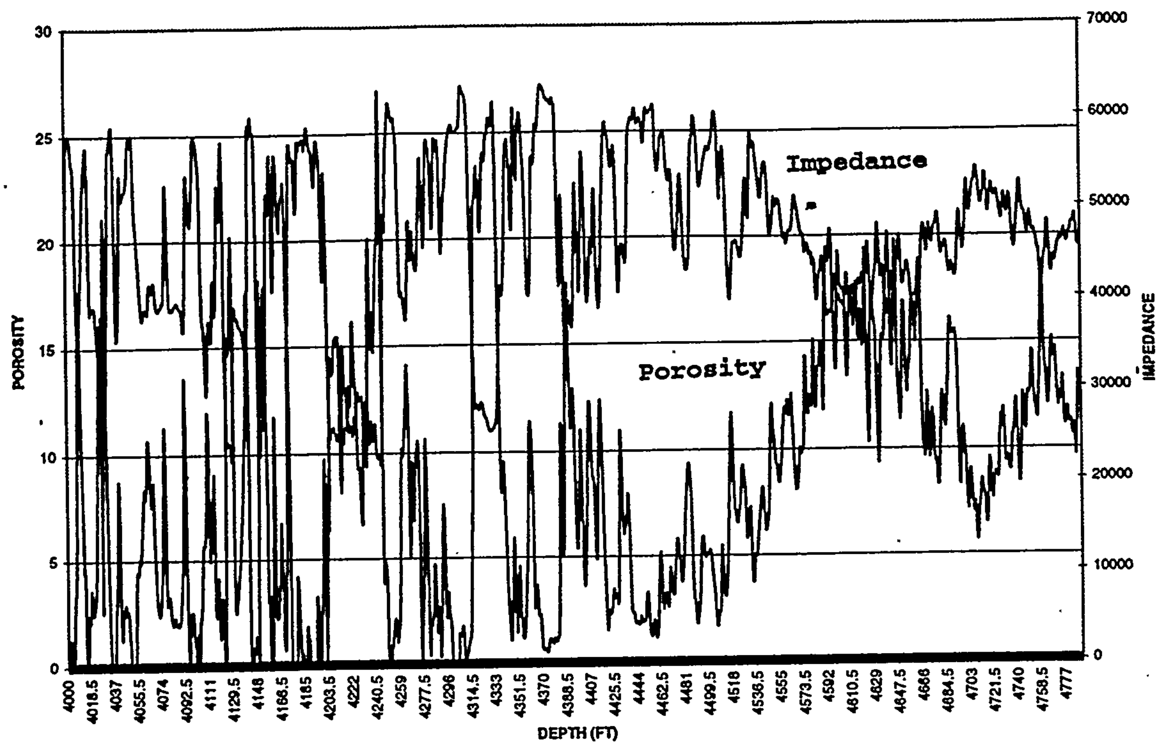


FIGURE 52A

WELL EMM215

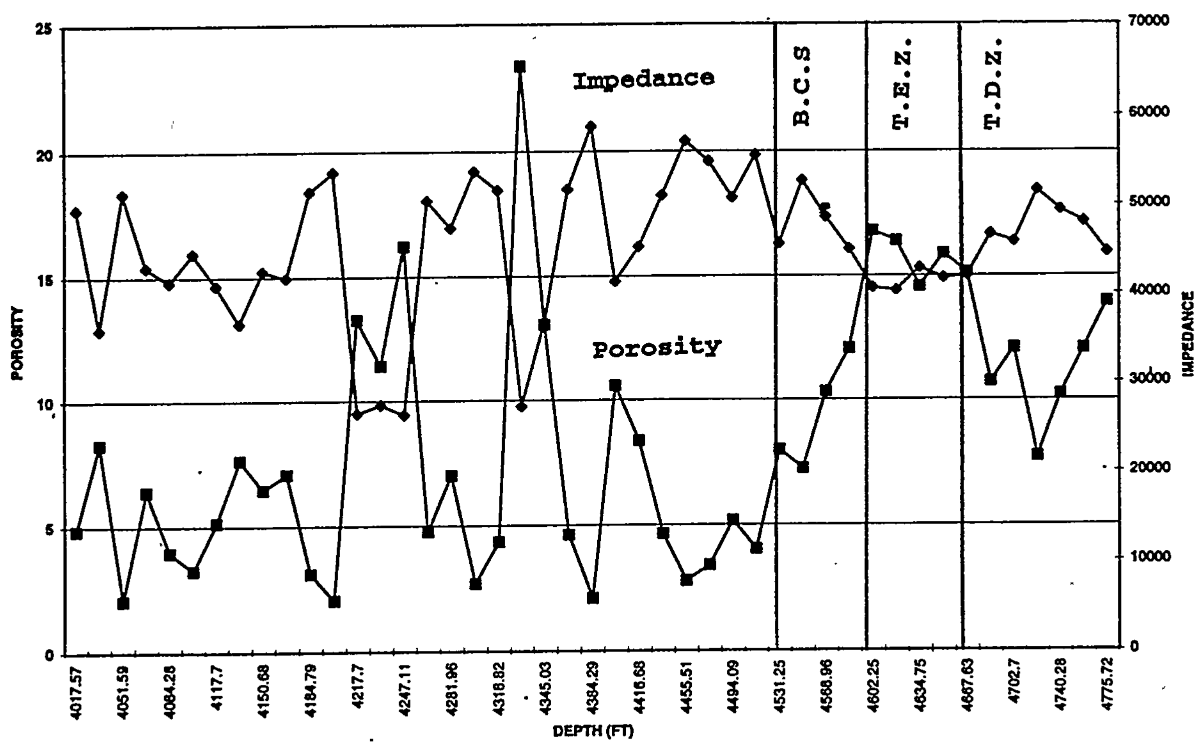


FIGURE 52B

WELL EMM215

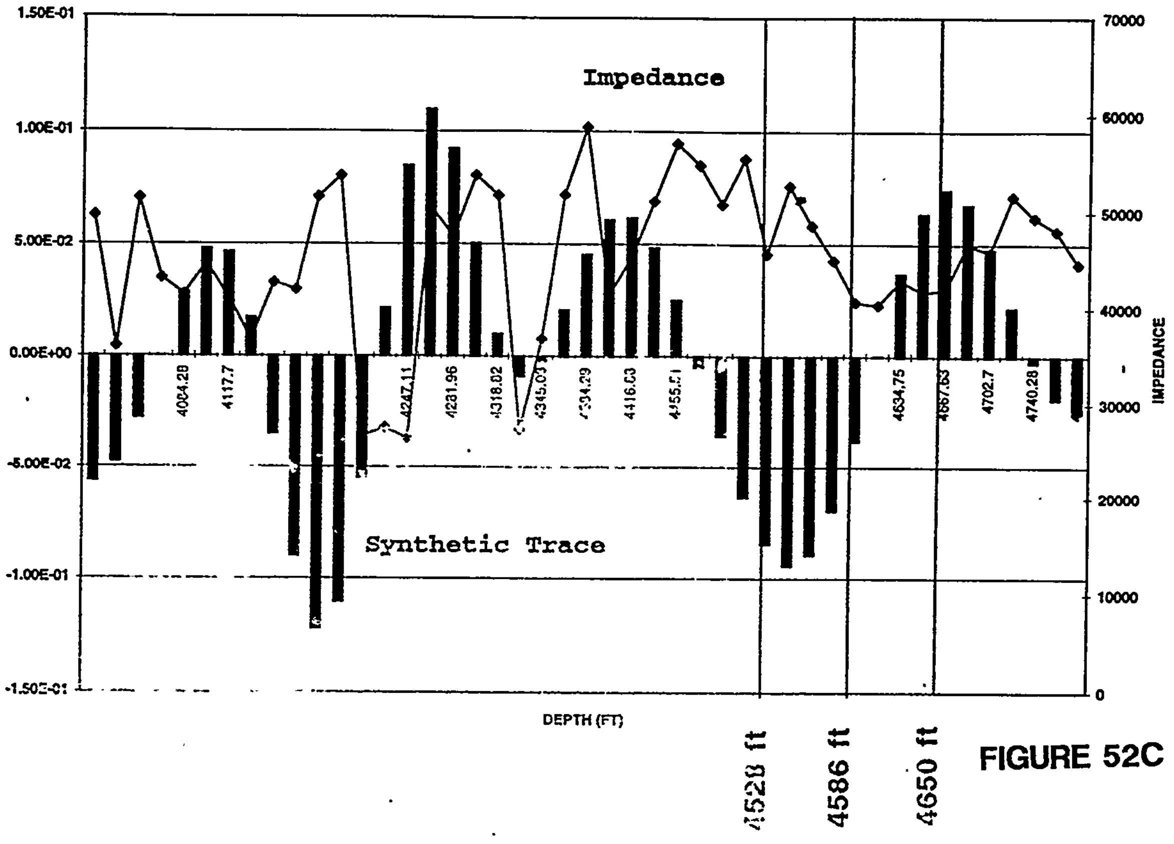


FIGURE 52C

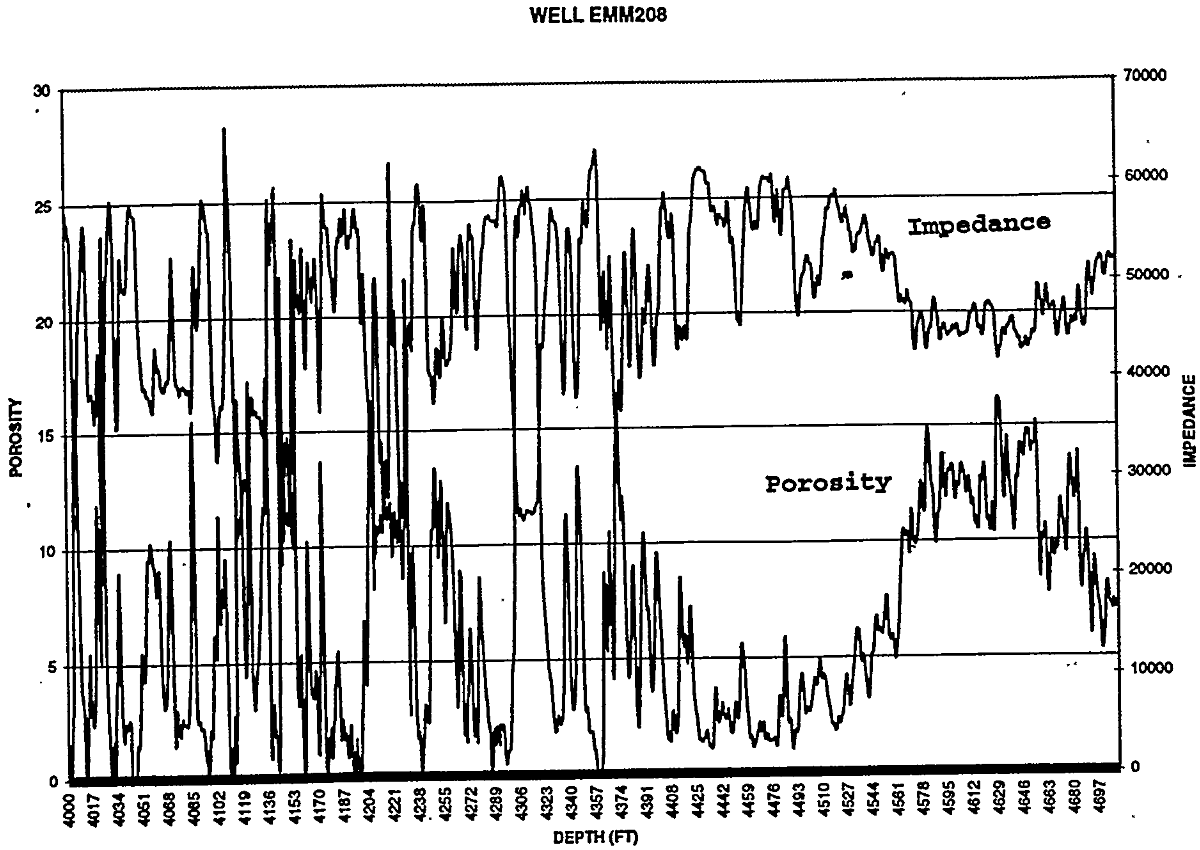


FIGURE 53A

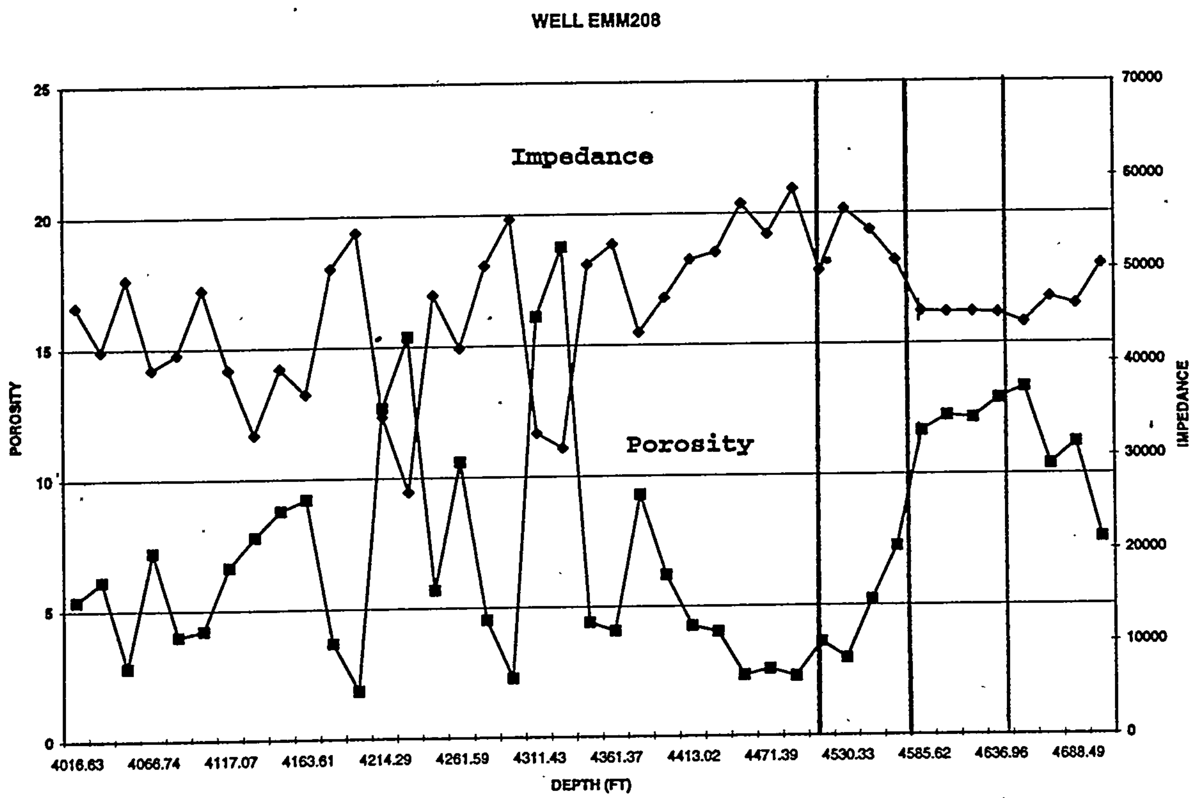


FIGURE 53B

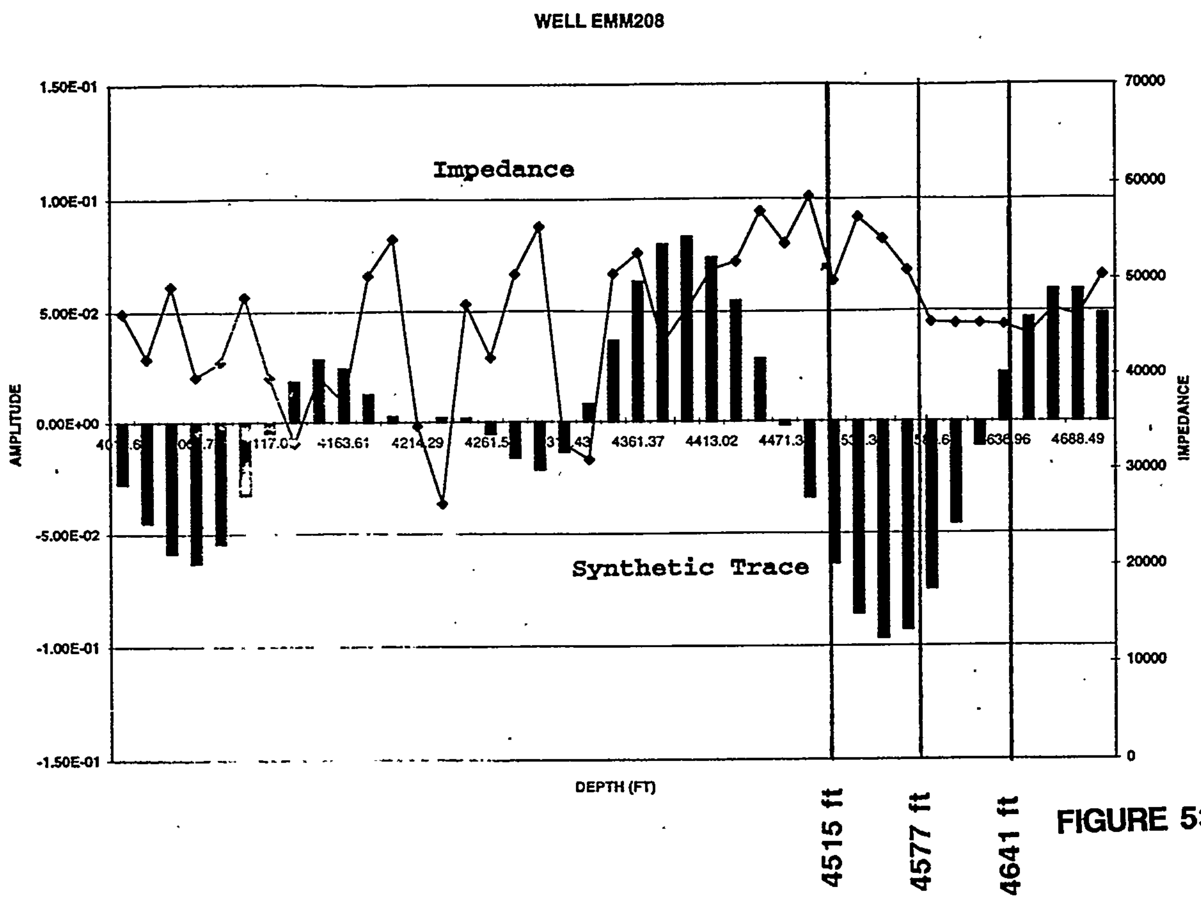

WELL EMM208
Impedance
Synthetic Trace
AMPLITUDE
IMPEDANCE
DEPTH (FT)
1.50E-01
1.00E-01
5.00E-02
0.00E+00
-5.00E-02
-1.00E-01
-1.50E-01
70000
60000
50000
40000
30000
20000
10000
0
4163.61
4214.29
4361.37
4413.02
4688.49
4515 ft
4577 ft
4641 ft

FIGURE 53C

WELL EMM124

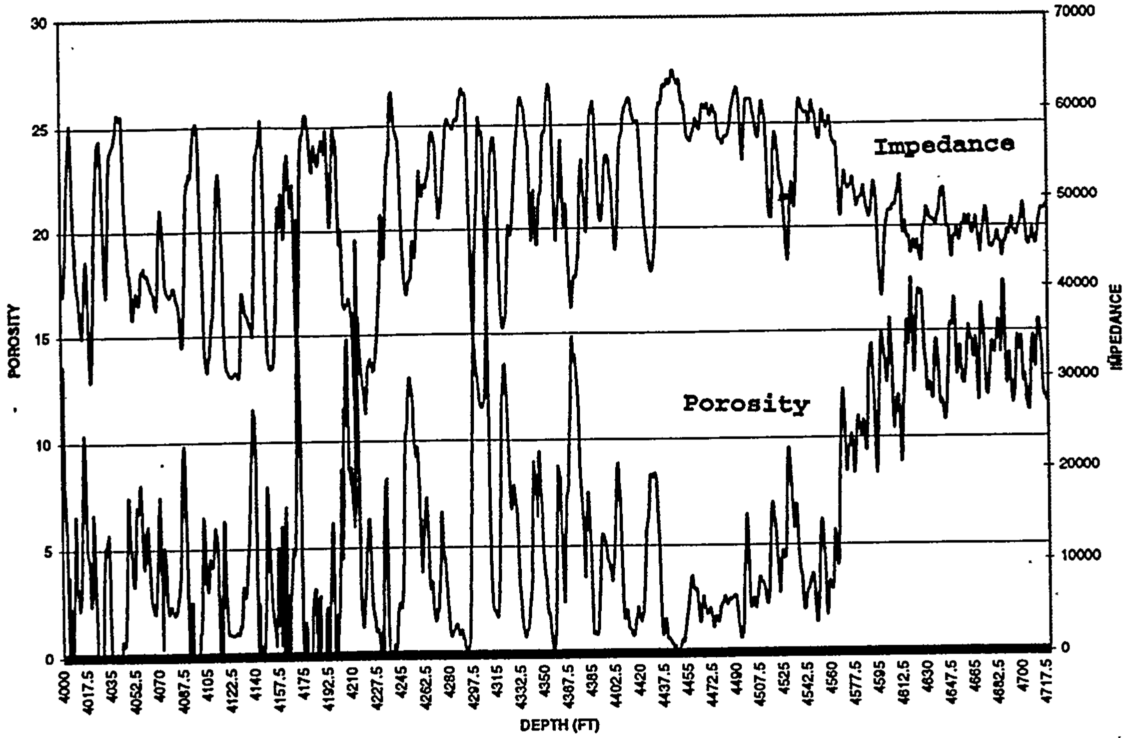


FIGURE 54A

WELL EMM124

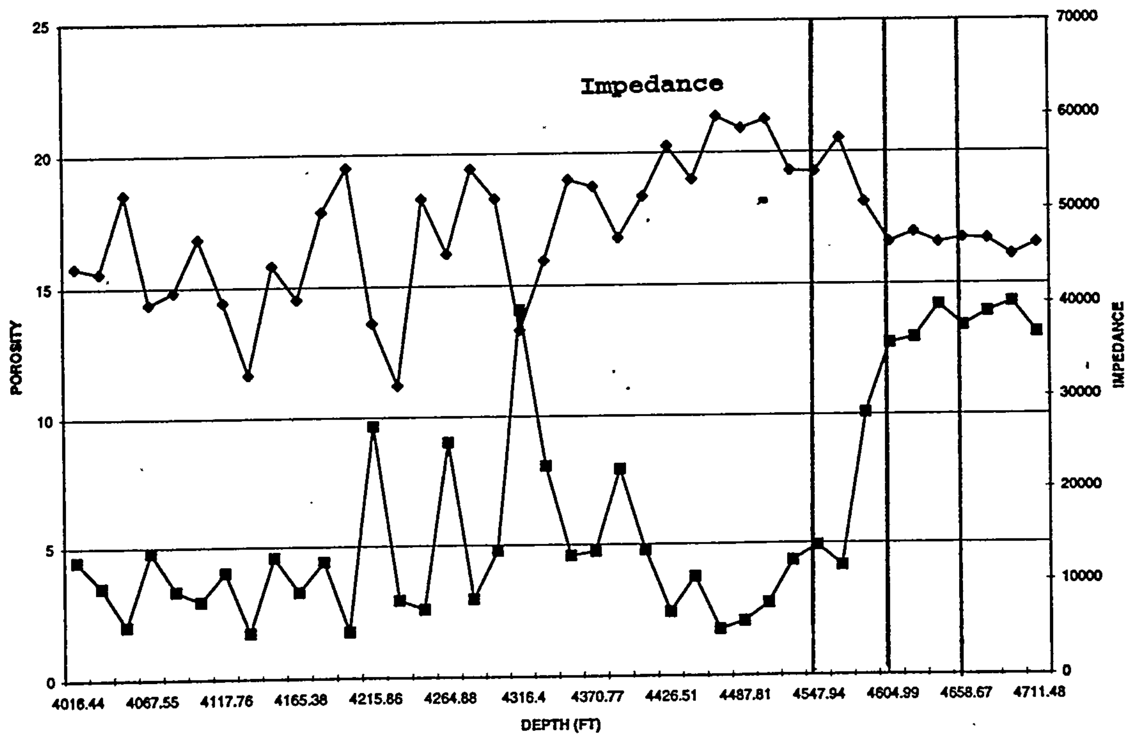


FIGURE 54B

WELL EMM124

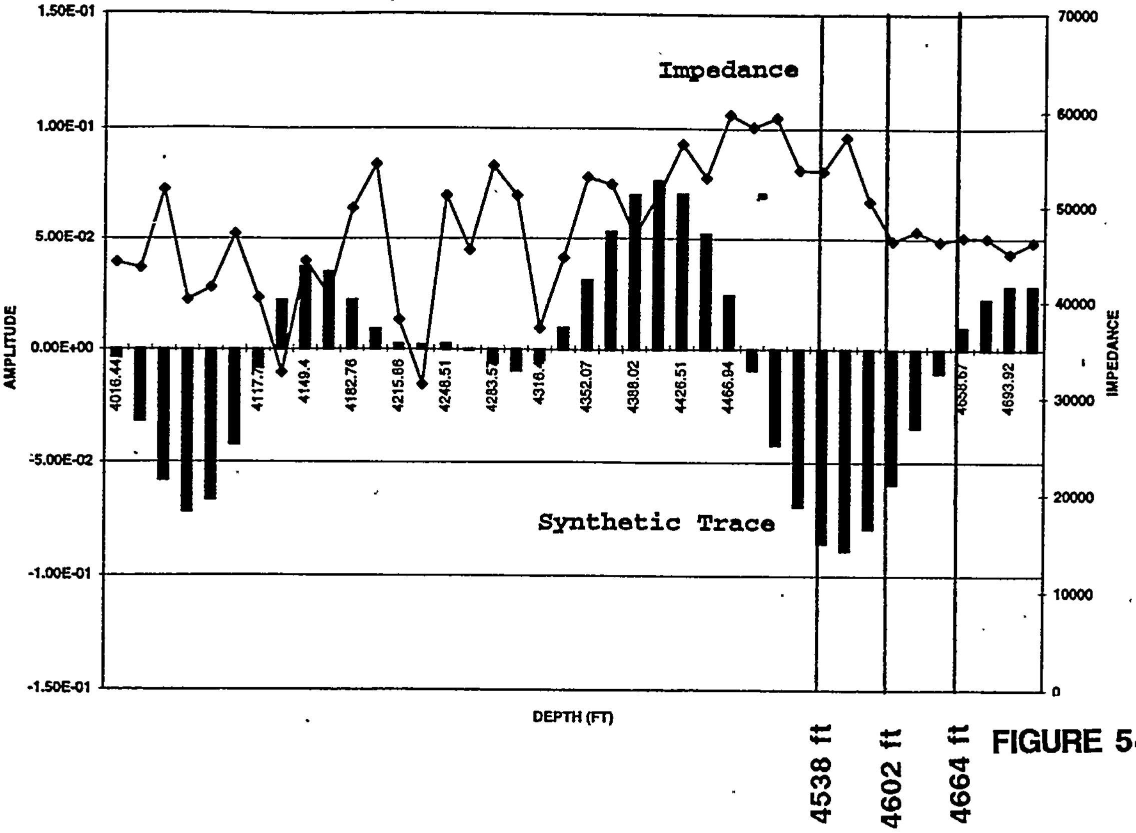


FIGURE 54C

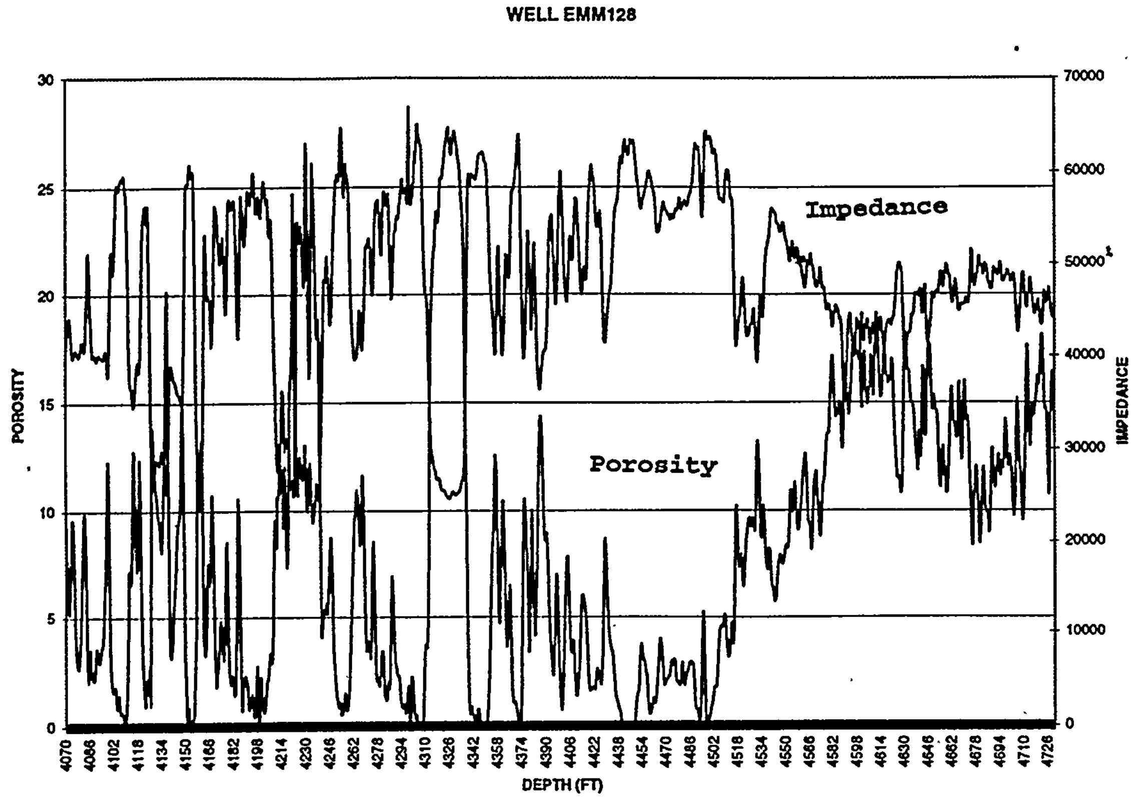


FIGURE 55A

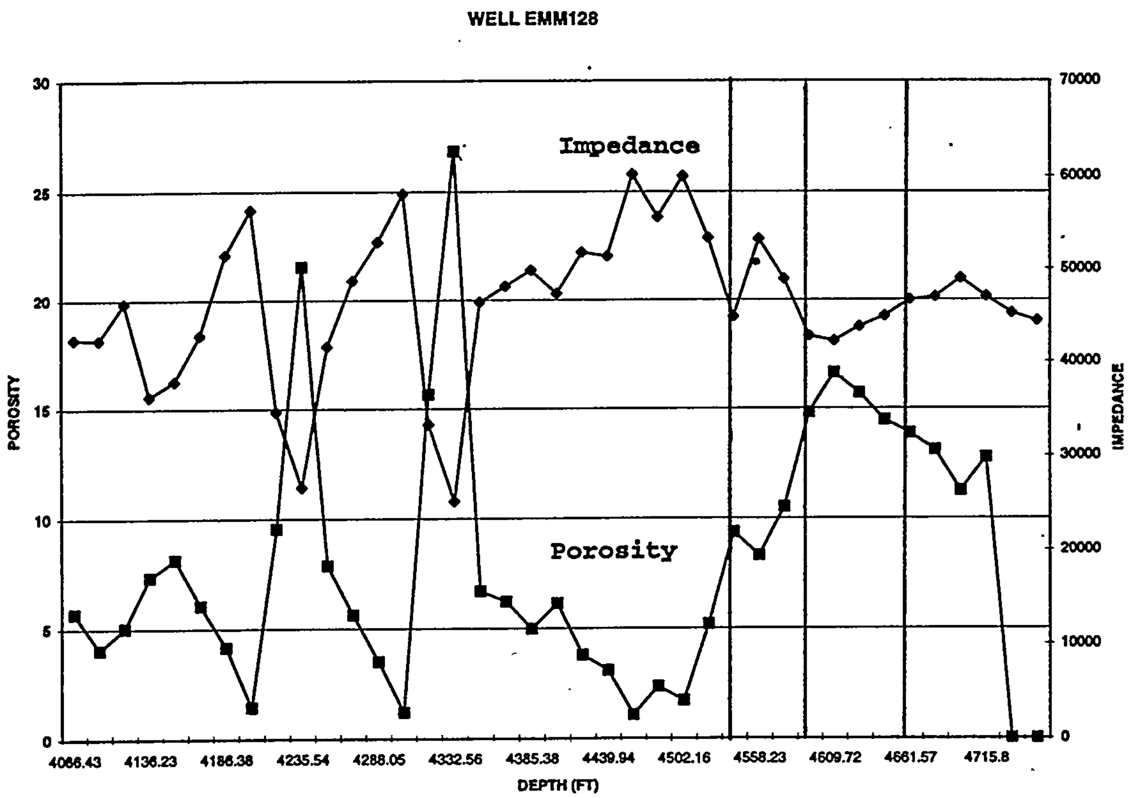
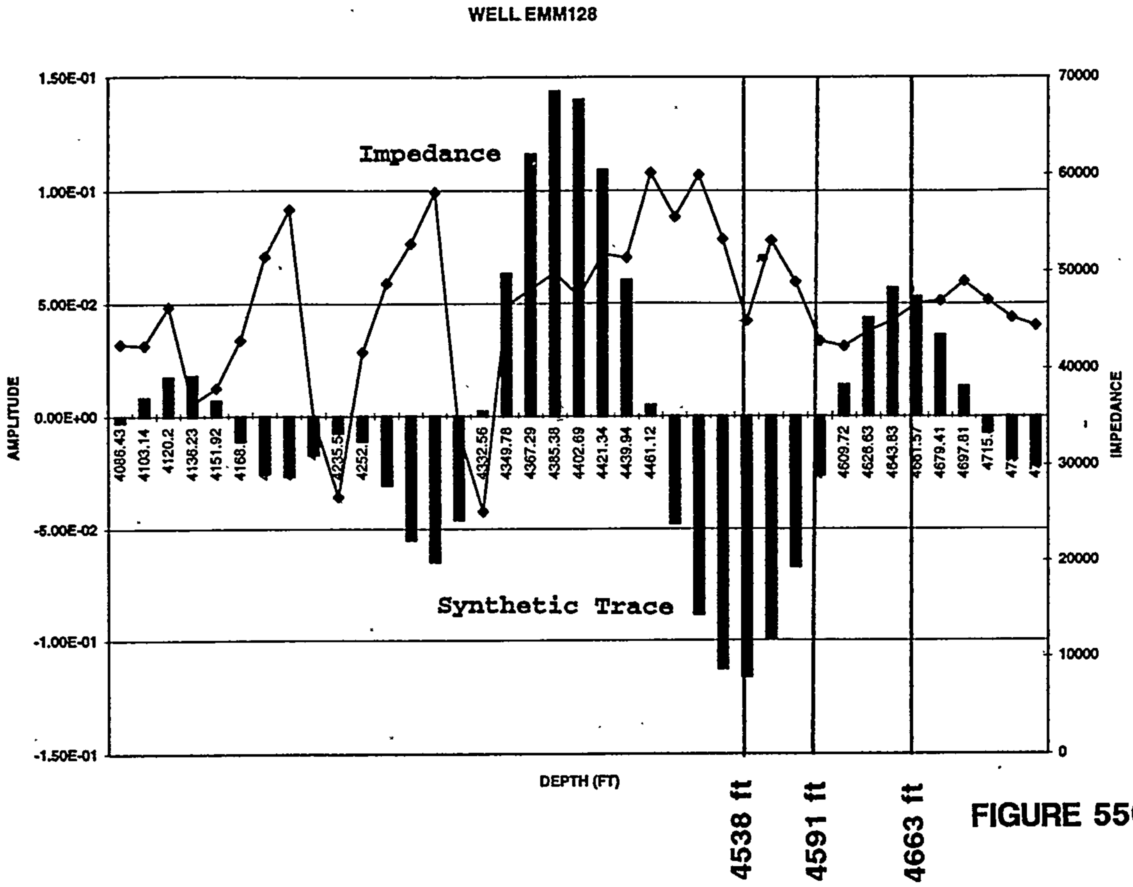


FIGURE 55B



WELL EMM128
Impedance
Synthetic Trace
AMPLITUDE
IMPEDANCE
DEPTH (FT)
1.50E-01
1.00E-01
5.00E-02
0.00E+00
-5.00E-02
-1.00E-01
-1.50E-01
70000
60000
50000
40000
30000
20000
10000
0
4086.43
4103.14
4120.2
4136.23
4151.92
4168.
4235.5
4252.
4332.56
4349.78
4367.29
4385.38
4402.69
4421.34
4439.94
4461.12
4609.72
4626.63
4643.83
4661.57
4679.41
4697.81
4715.
4538 ft
4591 ft
4663 ft

FIGURE 55C

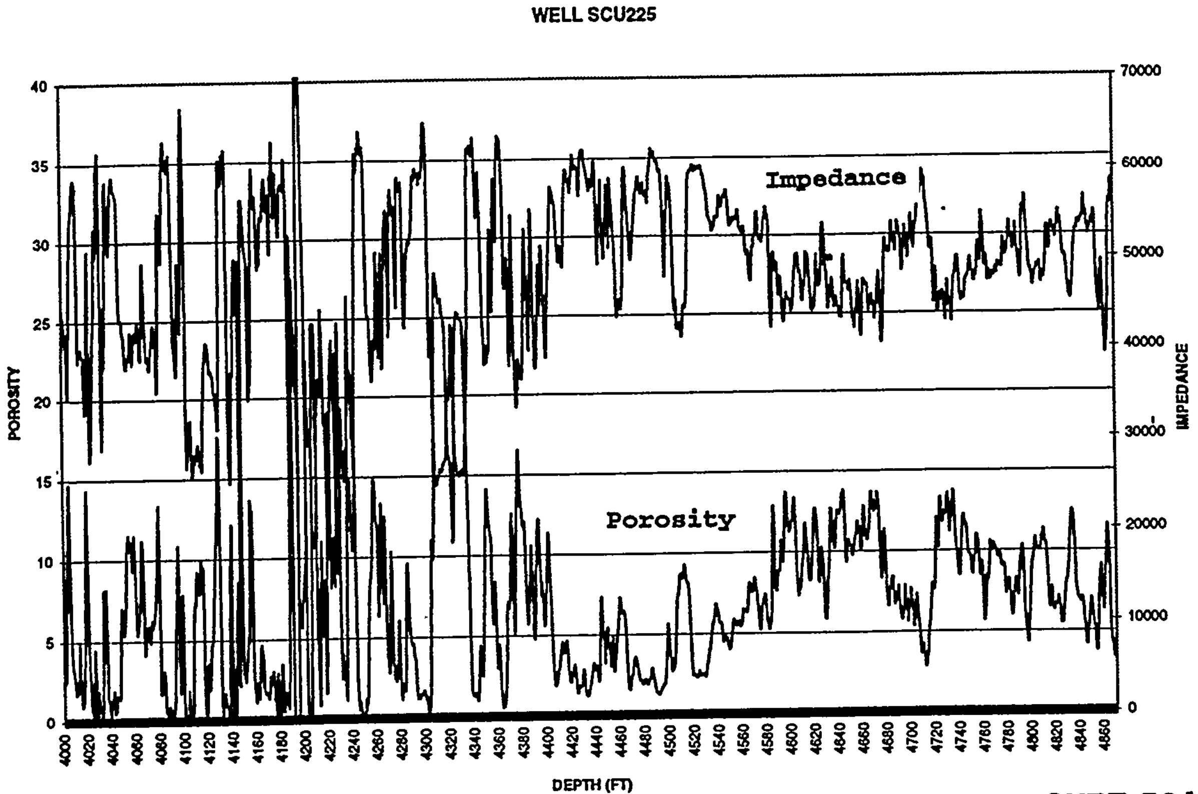


FIGURE 56A

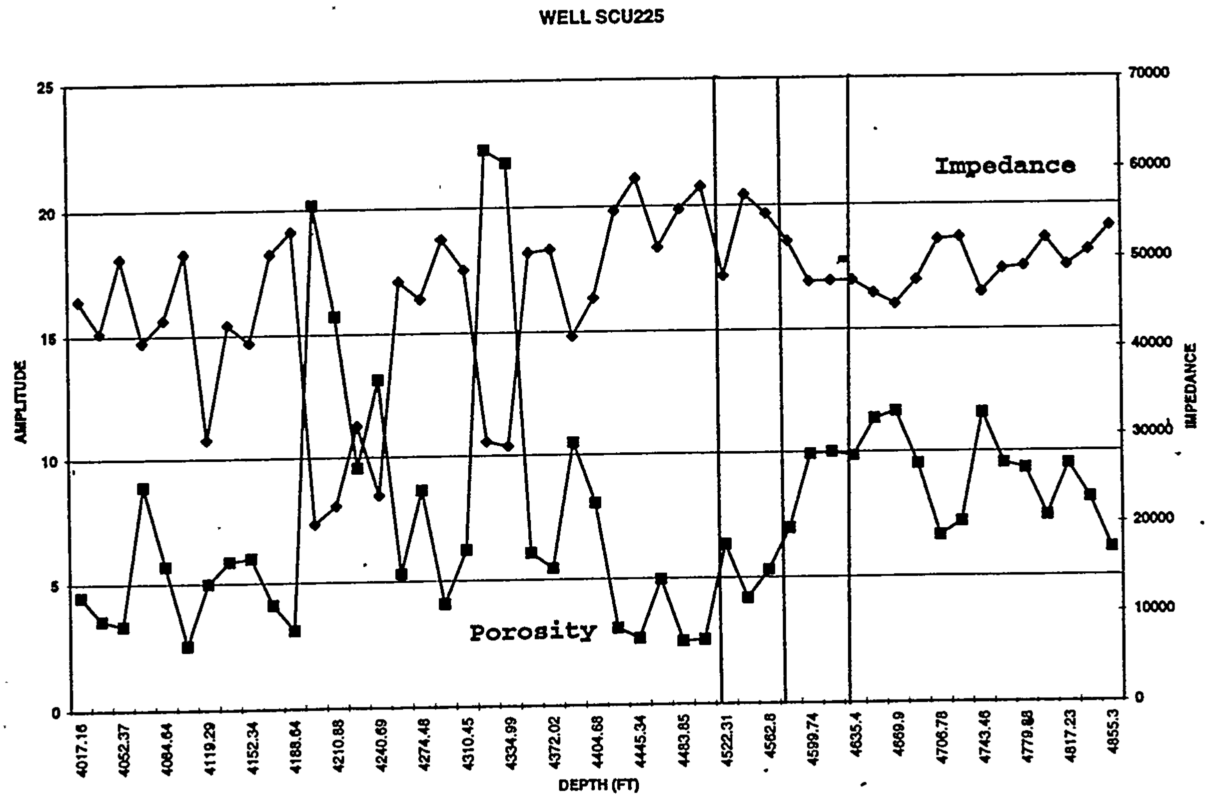


FIGURE 56B

WELL SCU225

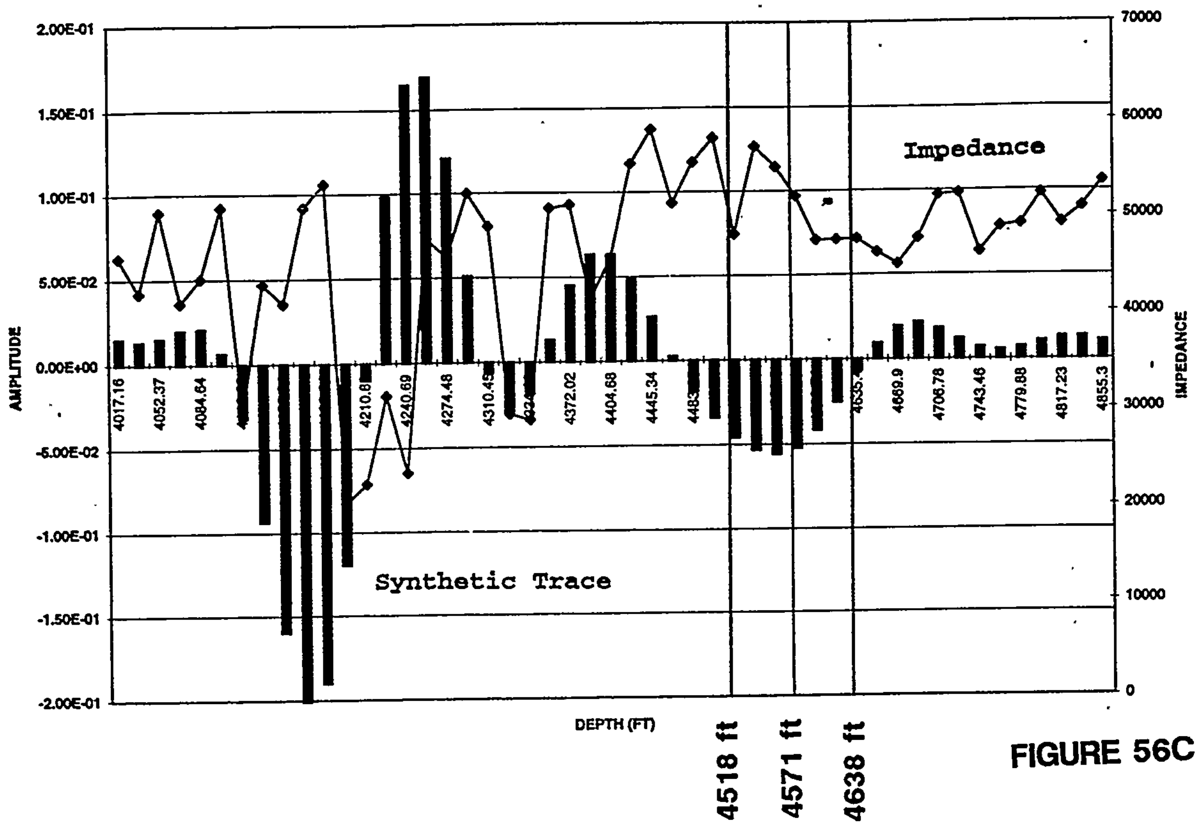
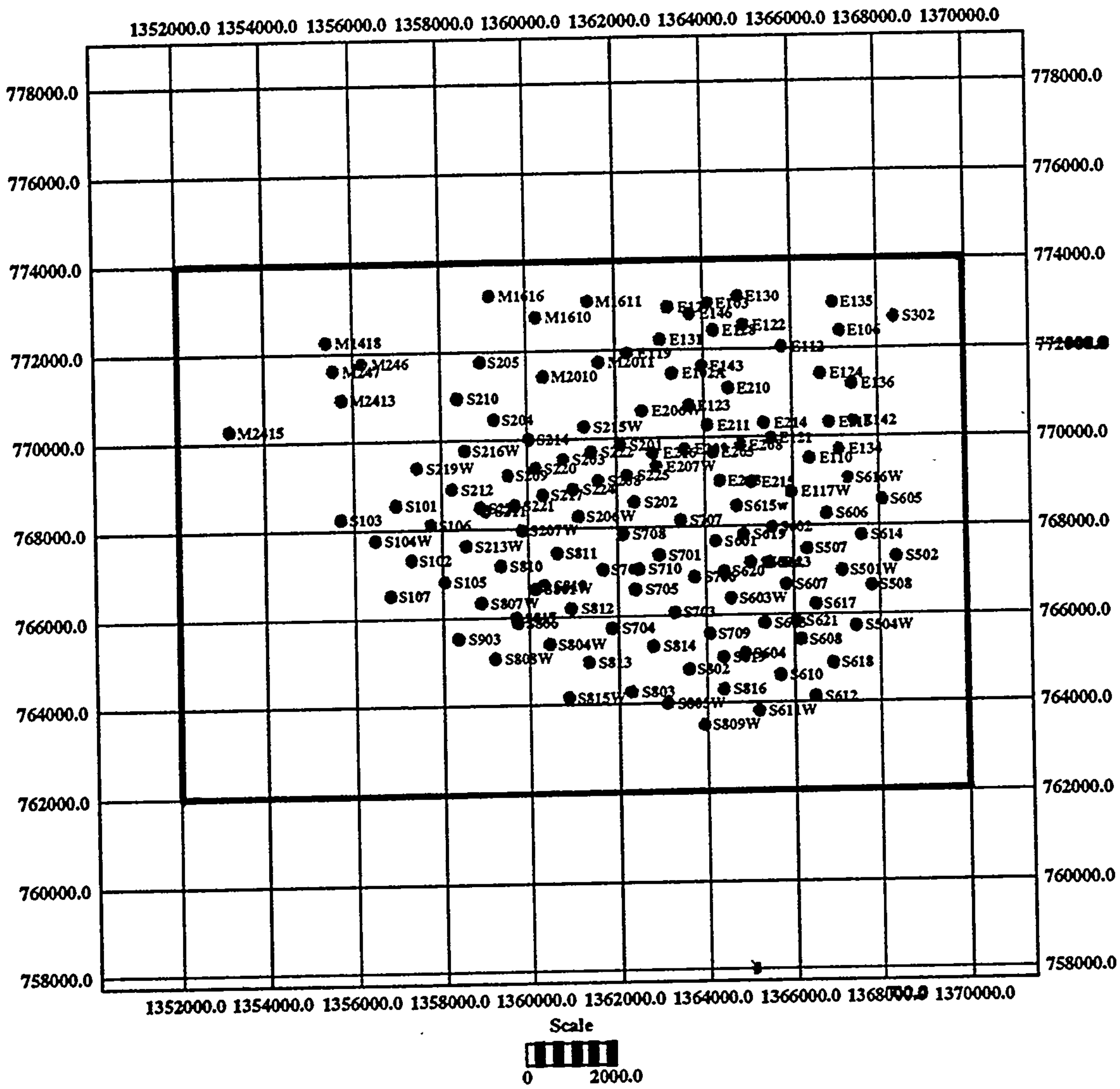


FIGURE 56C

FIGURE 57

Well Base Map Locations / Modeled Area



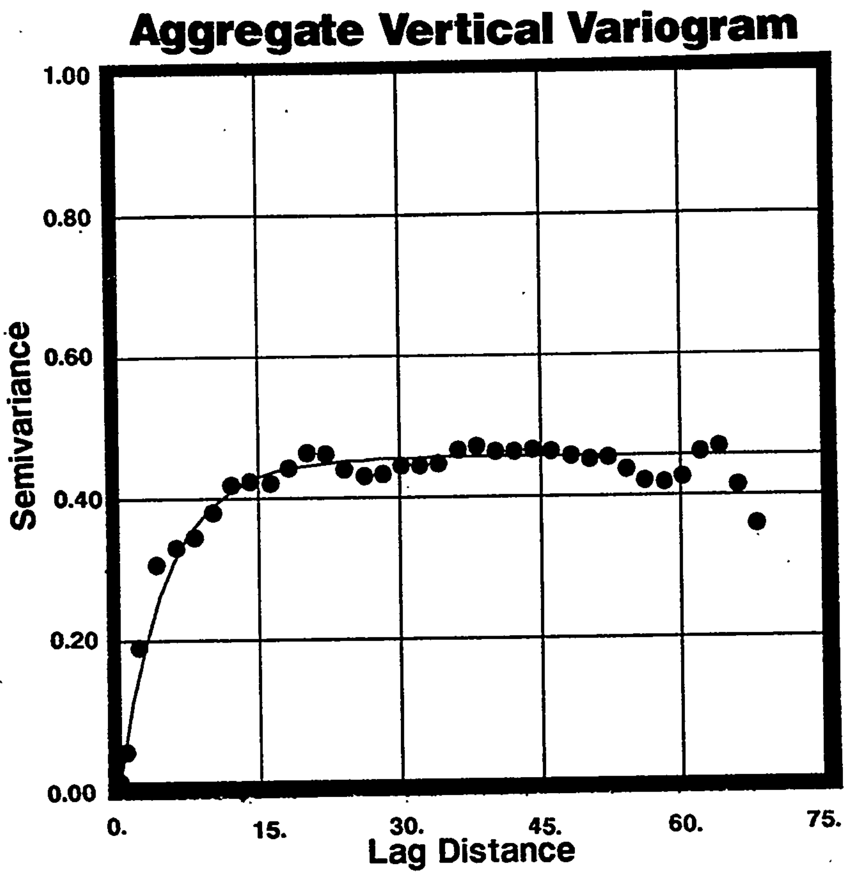


FIGURE 58A

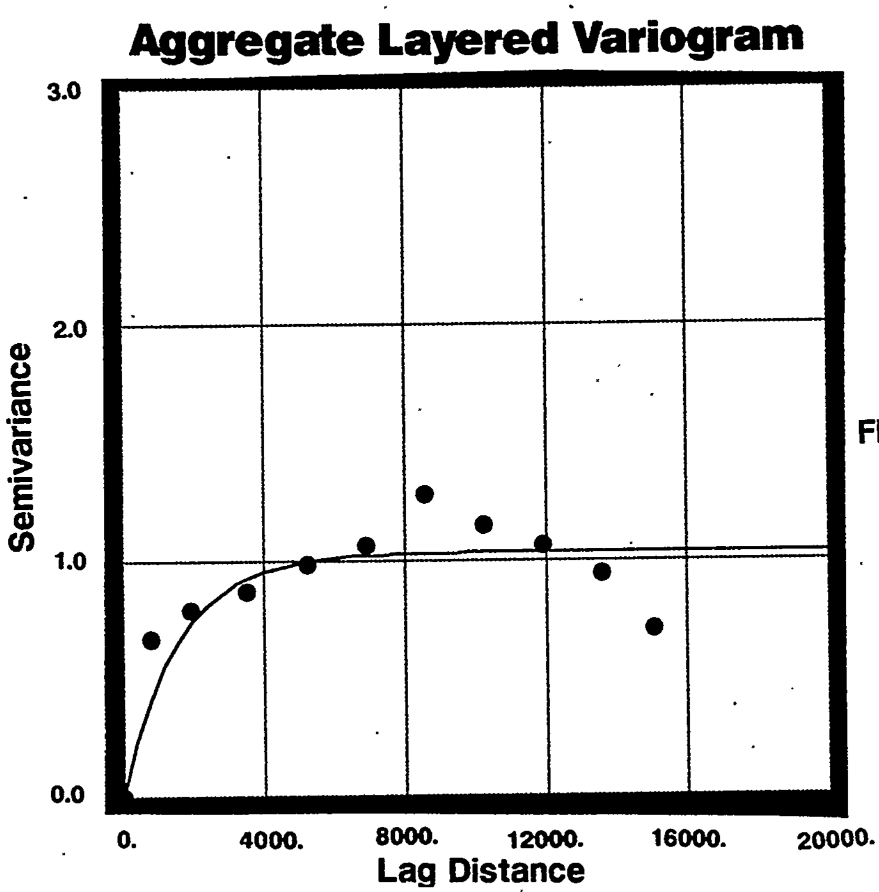


FIGURE 58B

Z Variograms and Variograms fits of Core Porosity Data

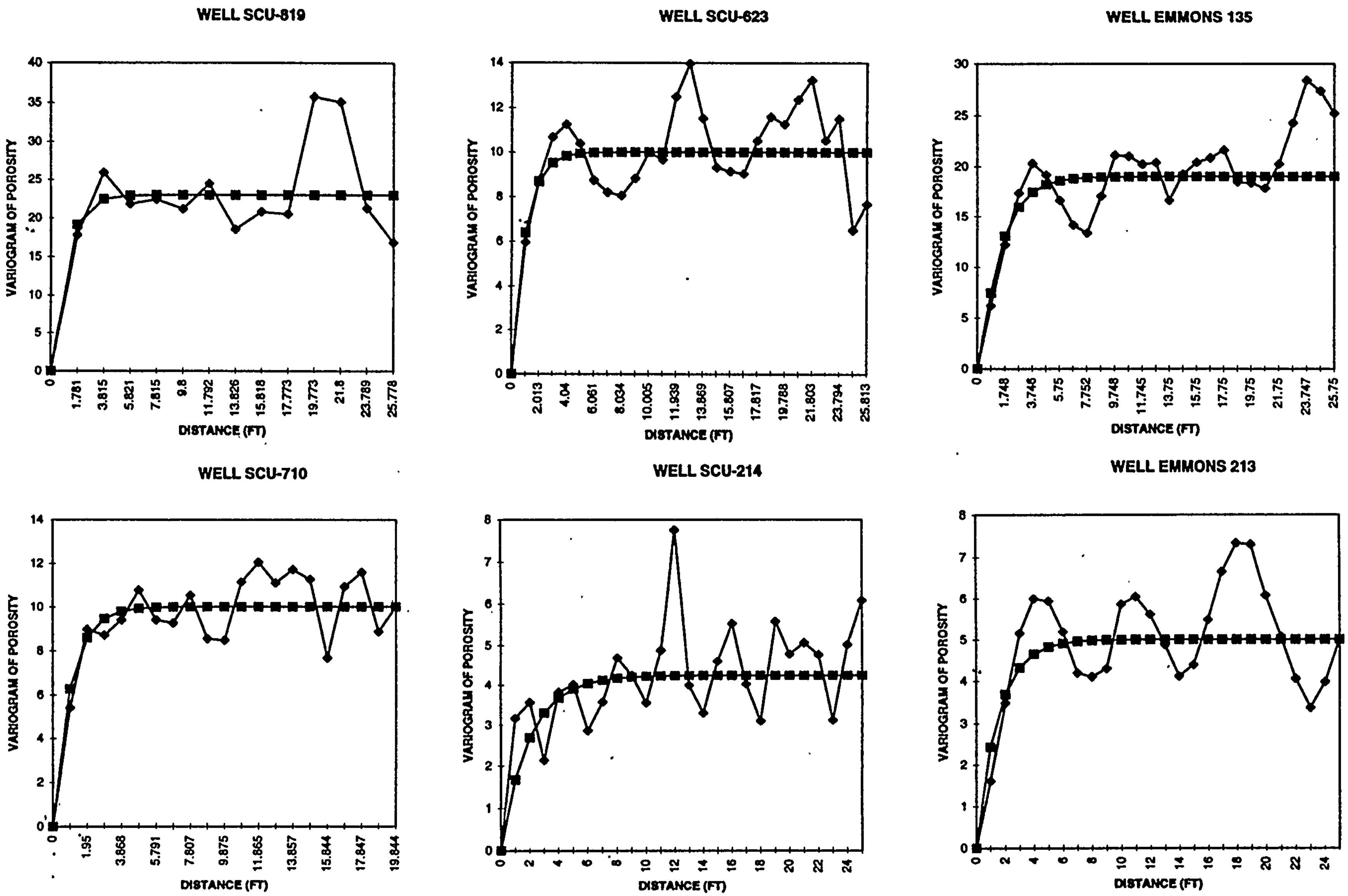


FIGURE 58C

North-South Porosity Cross Section

Column 90

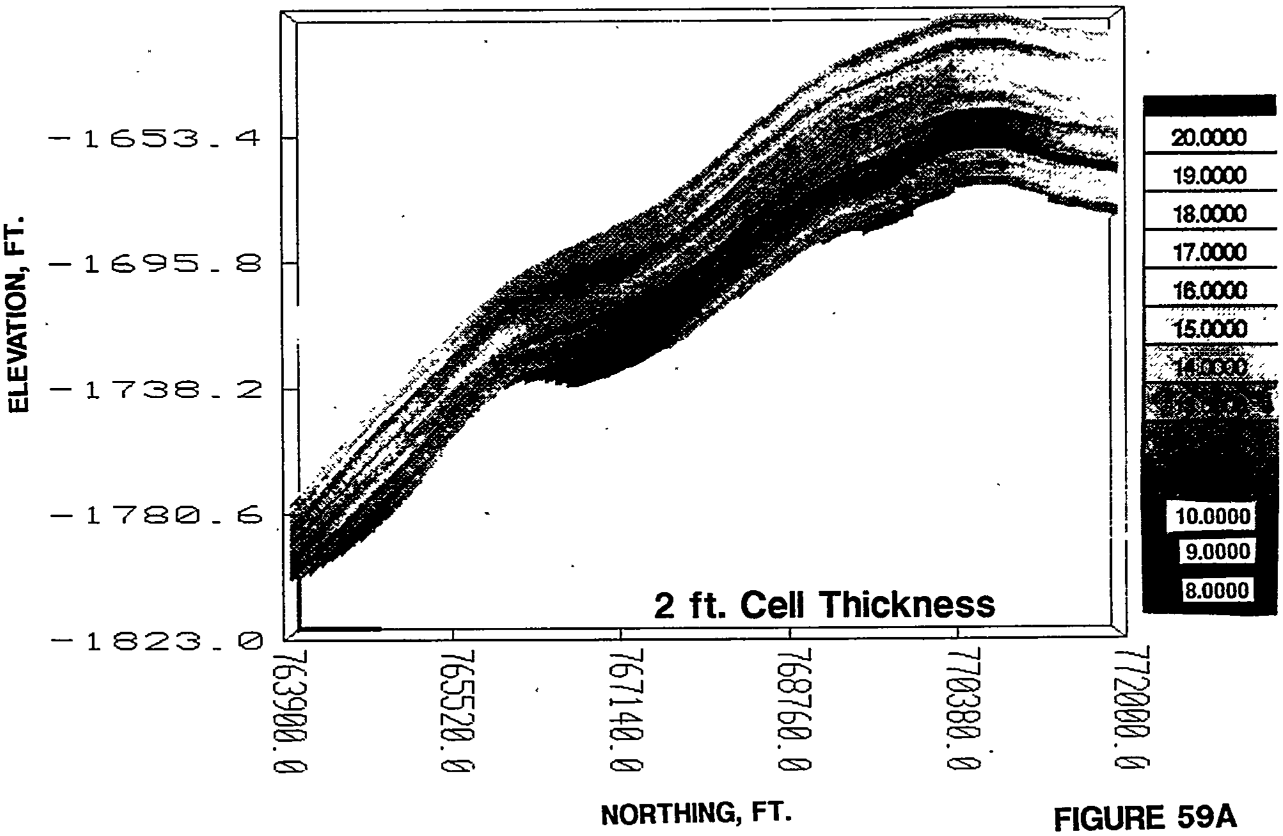


FIGURE 59A

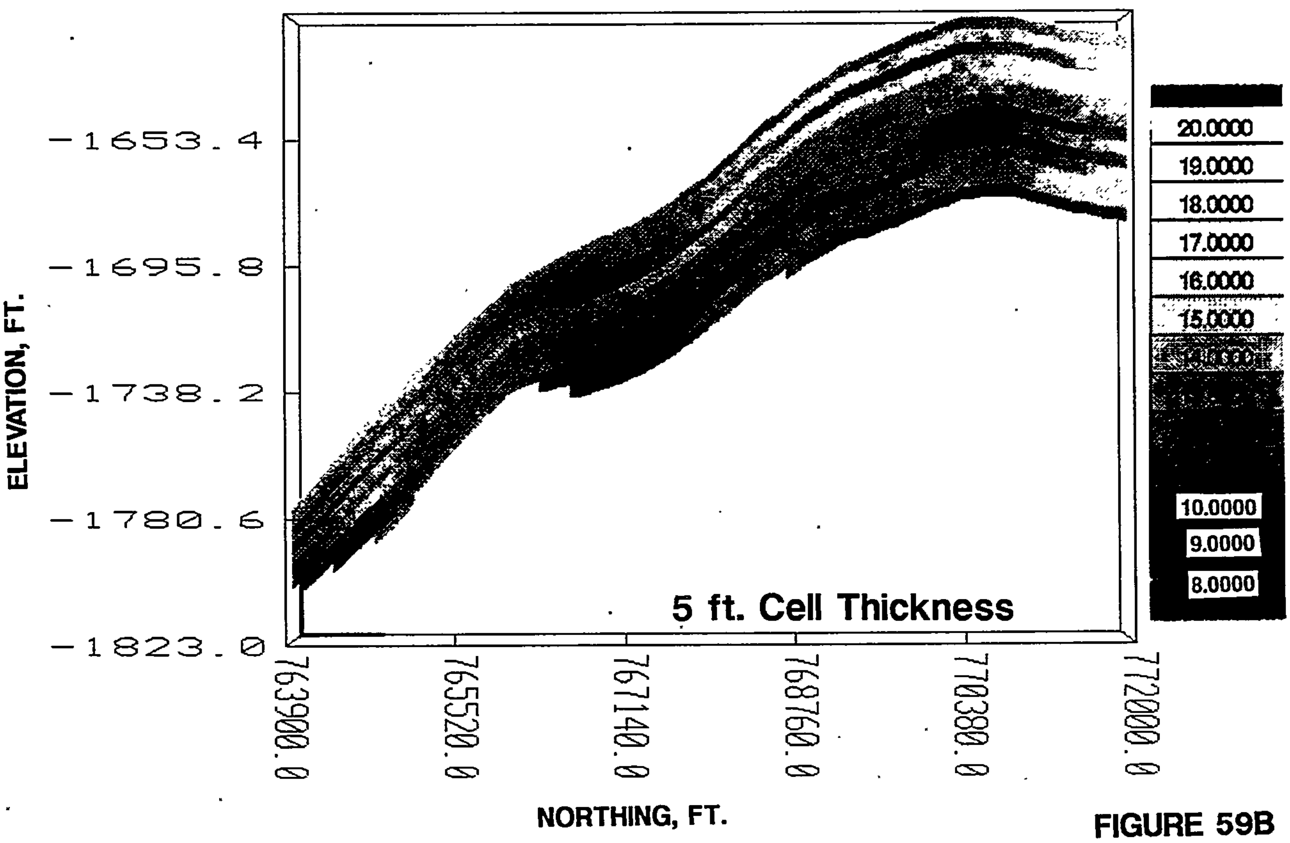


FIGURE 59B

North-South Porosity Cross Section
Column 90

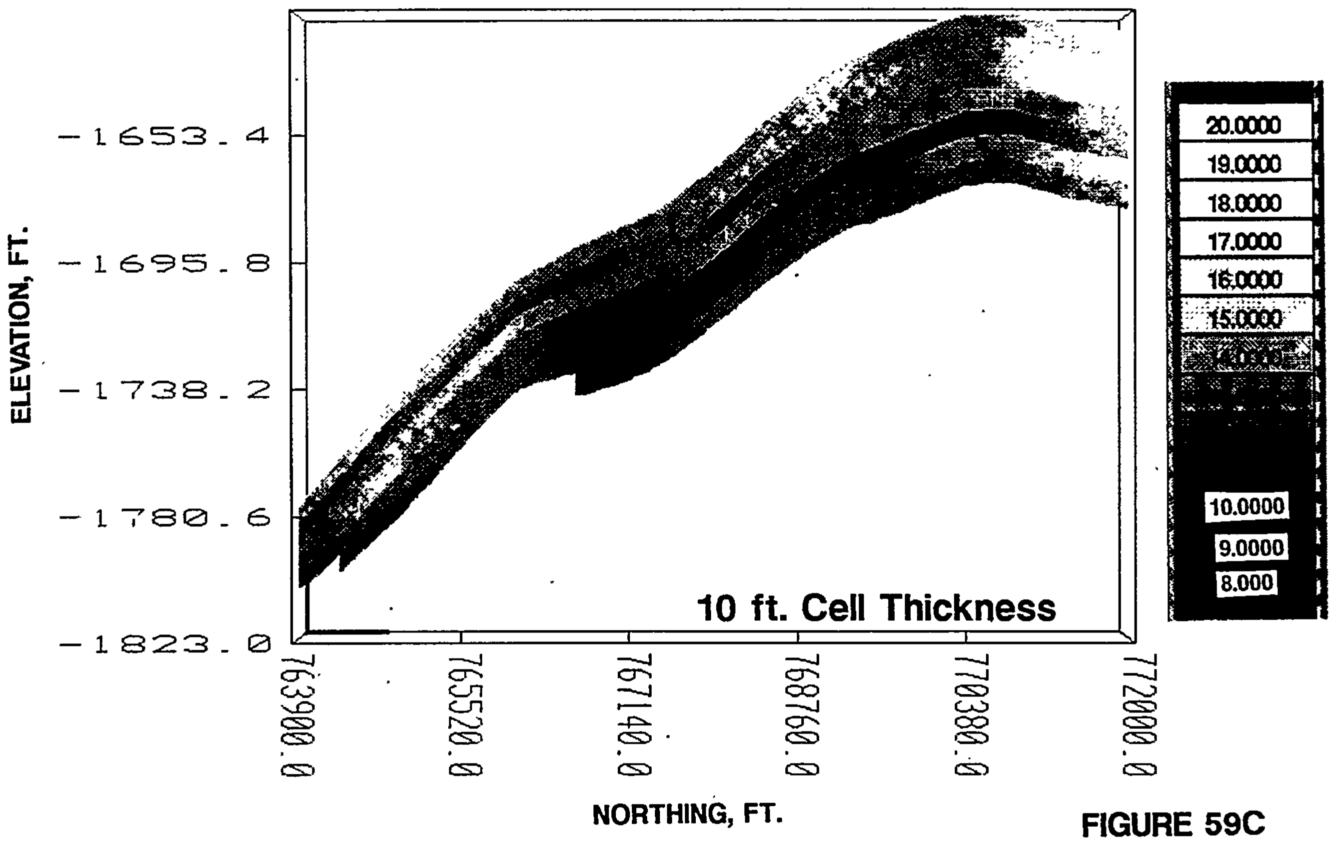
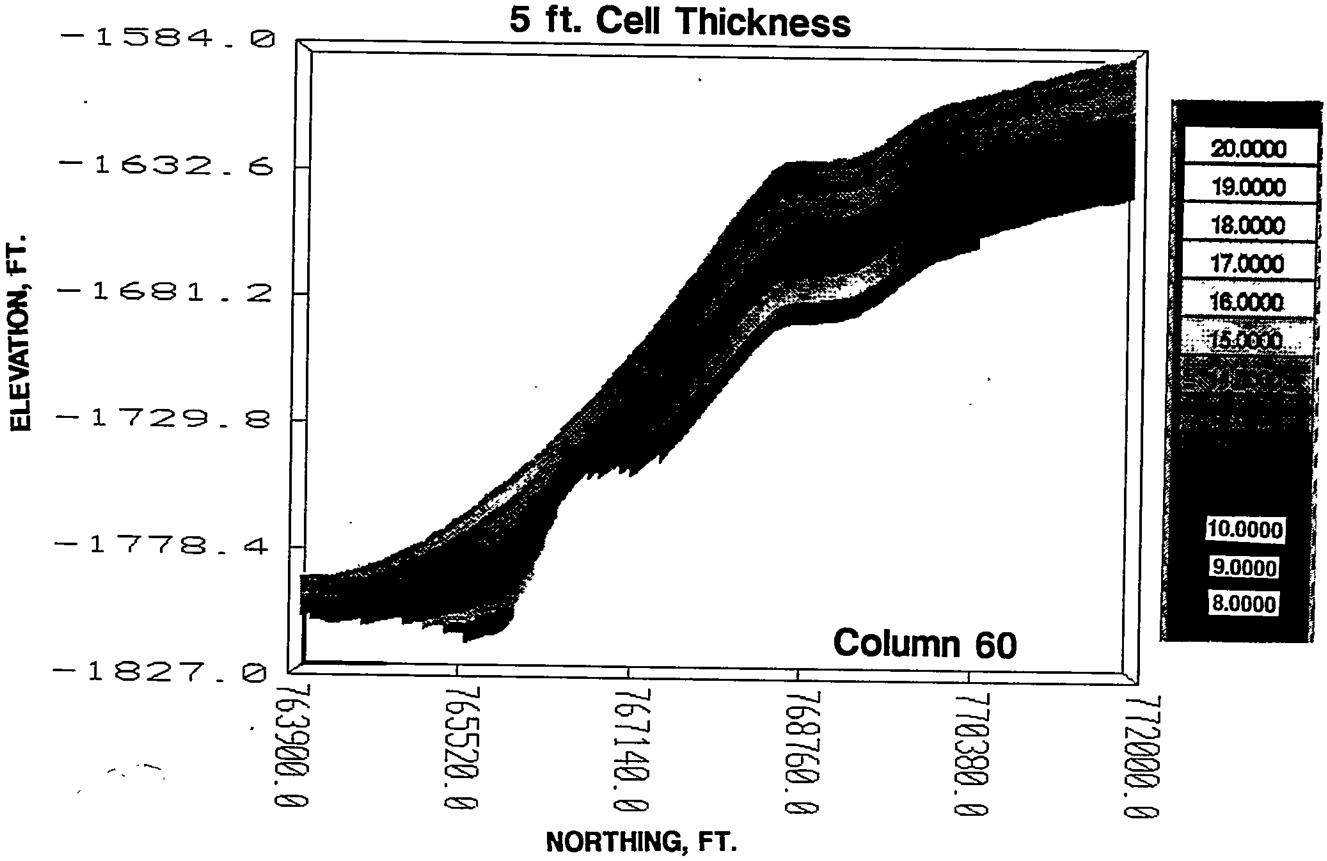


FIGURE 59C

FIGURE 60

North-South Porosity Cross Section

5 ft. Cell Thickness



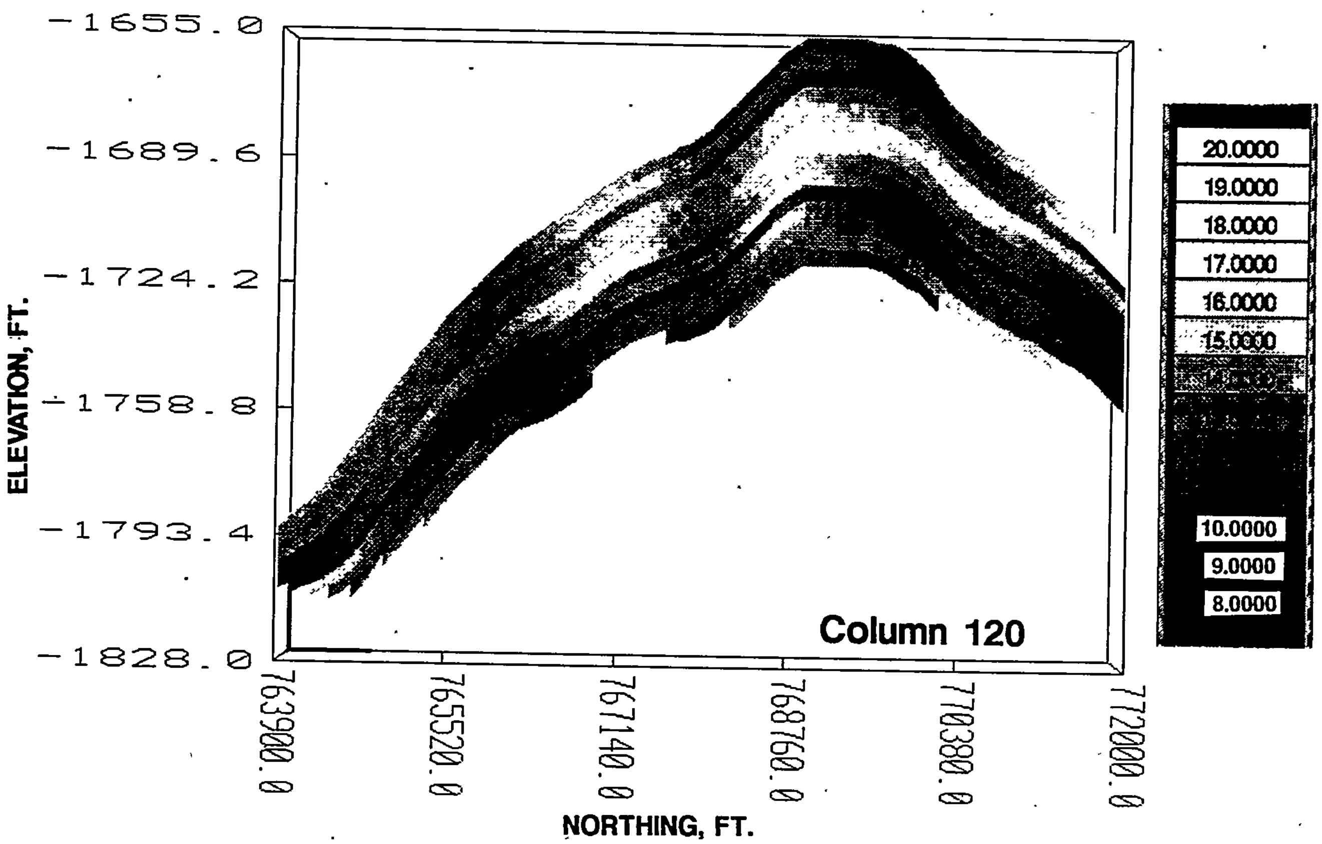


FIGURE 61

East-West Porosity Cross Section

5 ft. Cell Thickness

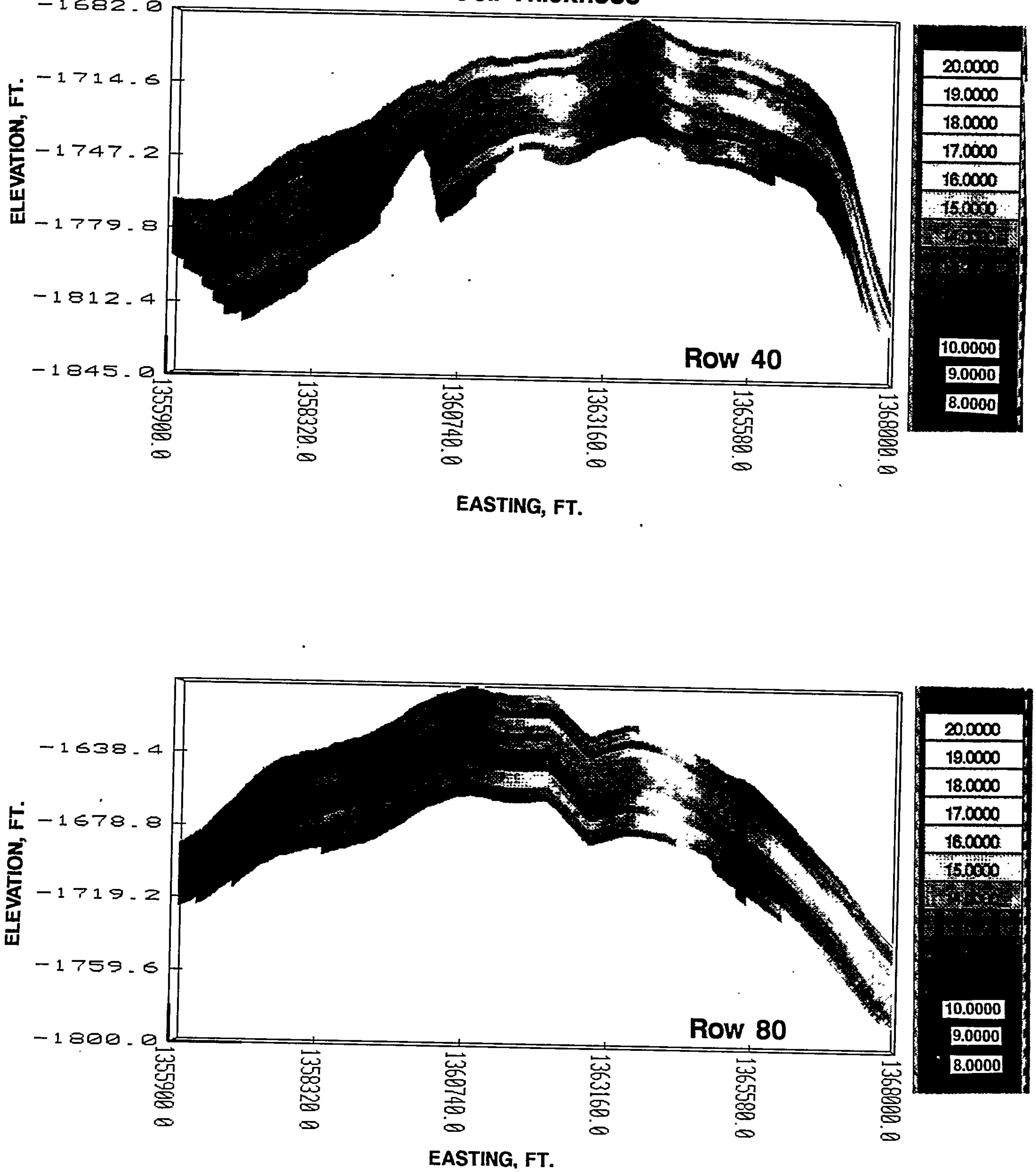
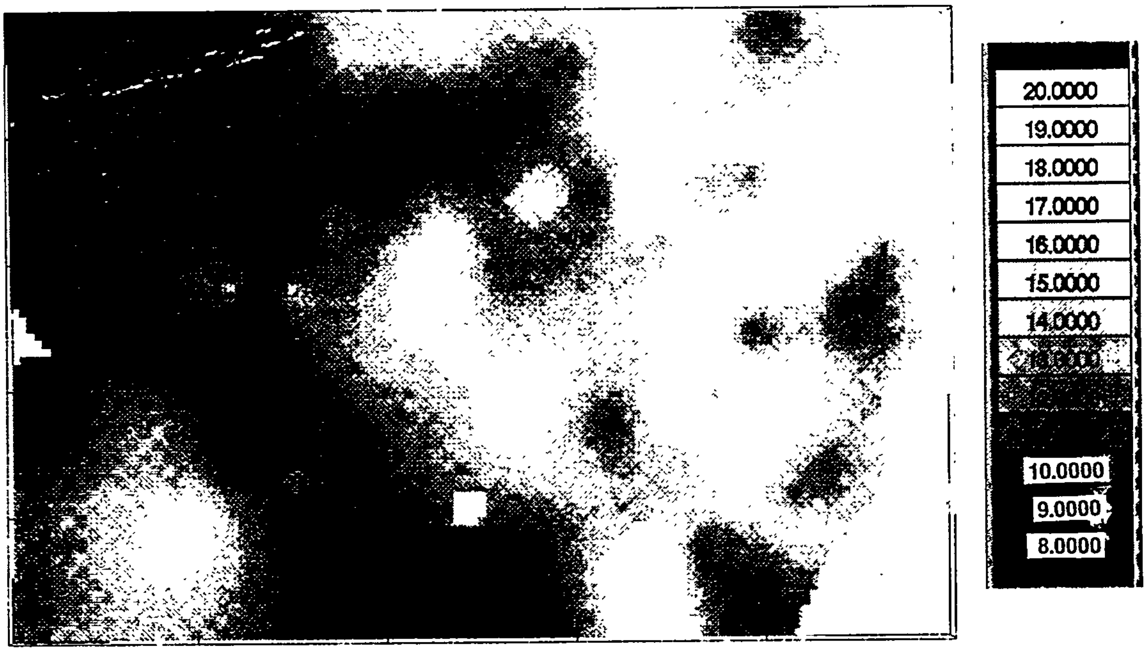


FIGURE 62

Porosity Surface Trends



25 ft. below Top of E Zone

50 ft. below Top of E Zone

FIGURE 63

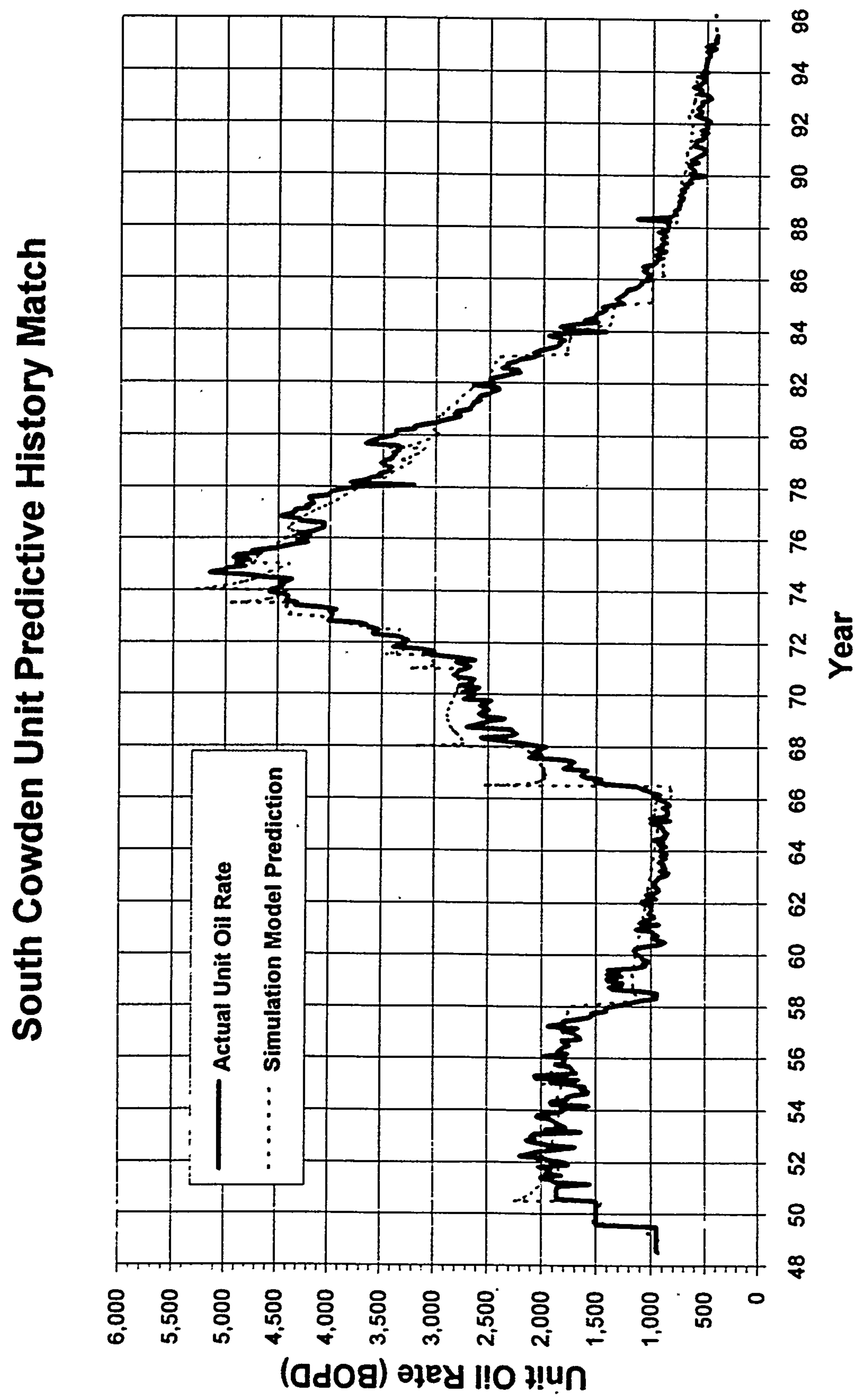
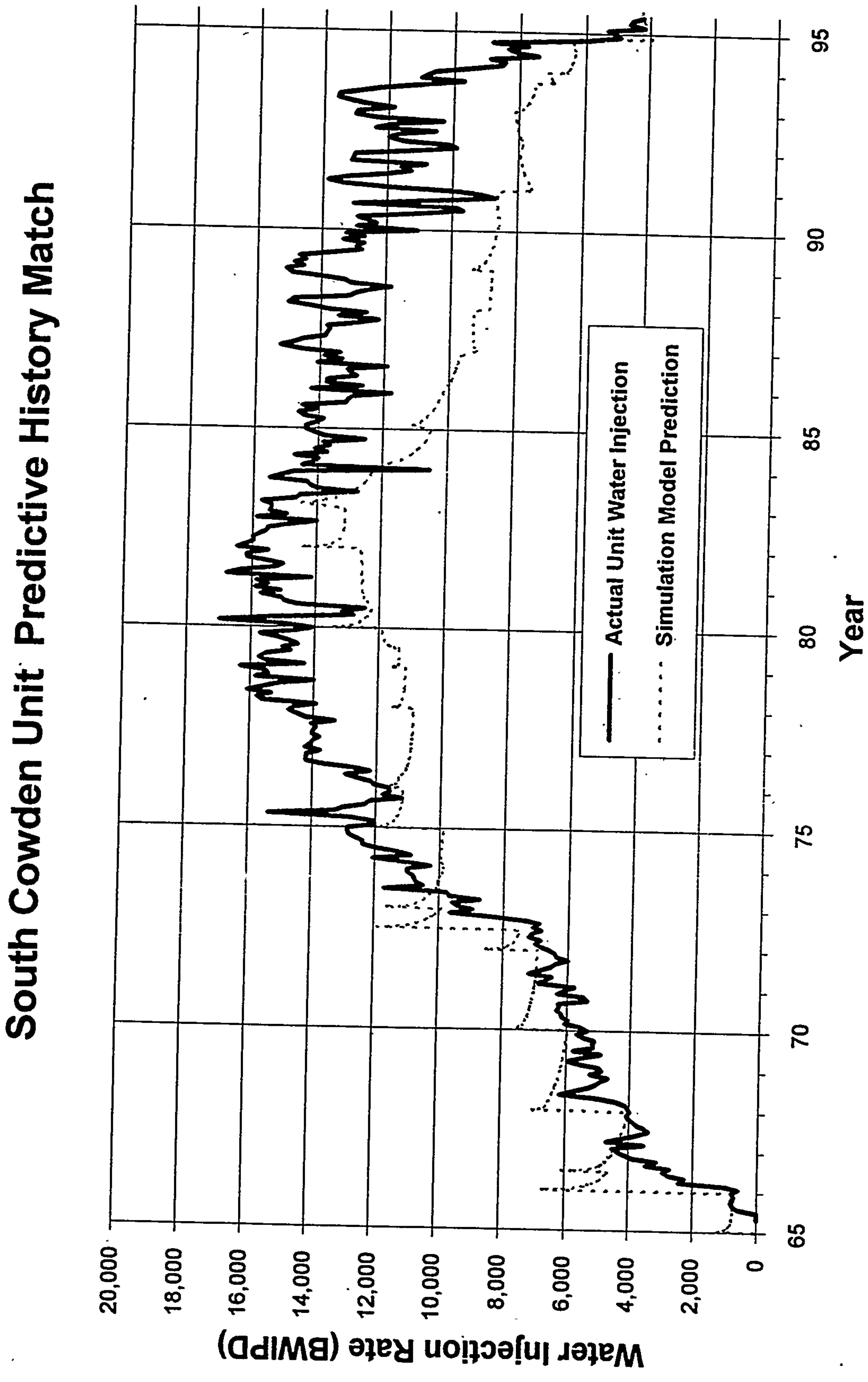

South Cowden Unit Predictive History Match
Actual Unit Oil Rate
Simulation Model Prediction
Unit Oil Rate (BOPD)
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
48
50
52
54
56
58
60
62
64
66
68
70
72
74
76
78
80
82
84
86
88
90
92
94
96
Year

FIGURE 64



South Cowden Unit Predictive History Match
Water Injection Rate (BWIPD)
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
65
70
75
80
85
90
95
Year
Actual Unit Water Injection
Simulation Model Prediction

FIGURE 65

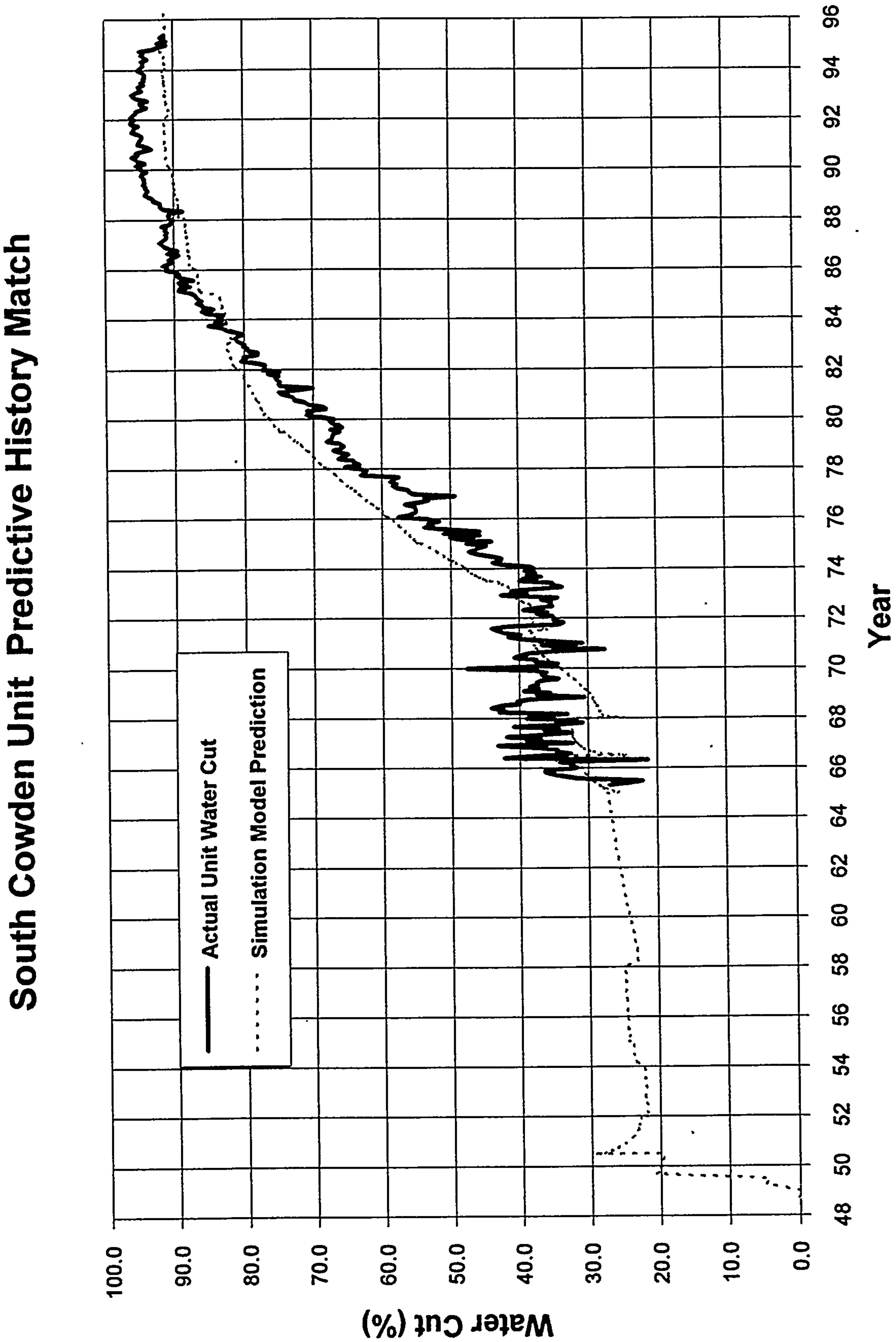
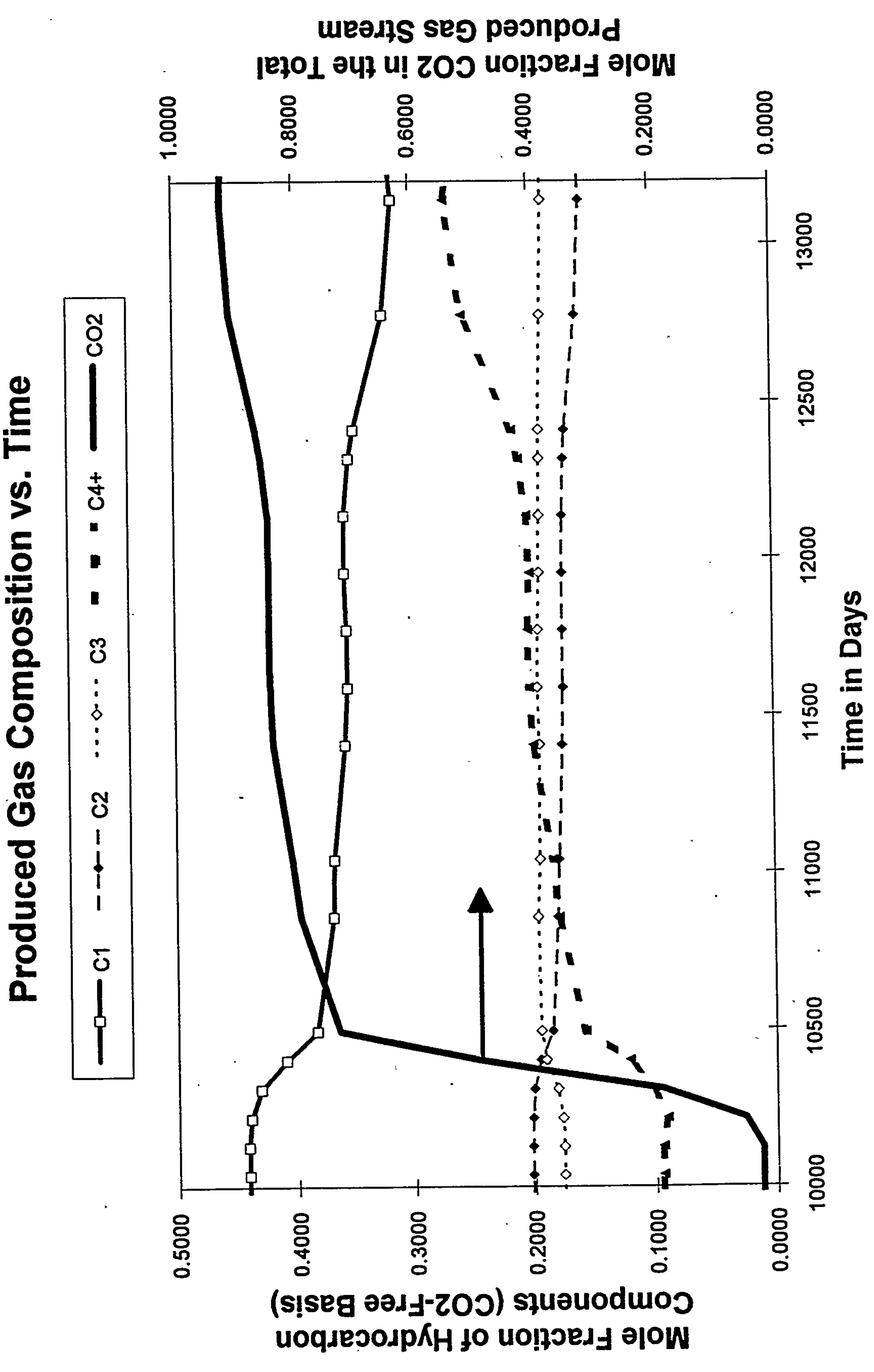

South Cowden Unit Predictive History Match
Actual Unit Water Cut
Simulation Model Prediction
Water Cut (%)
100.0
90.0
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
Year
48
50
52
54
56
58
60
62
64
66
68
70
72
74
76
78
80
82
84
86
88
90
92
94
96

FIGURE 66



Produced Gas Composition vs. Time
C1
C2
C3
C4+
CO2
Mole Fraction CO2 in the Total Produced Gas Stream
1.0000
0.8000
0.6000
0.4000
0.2000
0.0000
Mole Fraction of Hydrocarbon Components (CO2-Free Basis)
0.5000
0.4000
0.3000
0.2000
0.1000
0.0000
10000
10500
11000
11500
12000
12500
13000
Time in Days

FIGURE 67

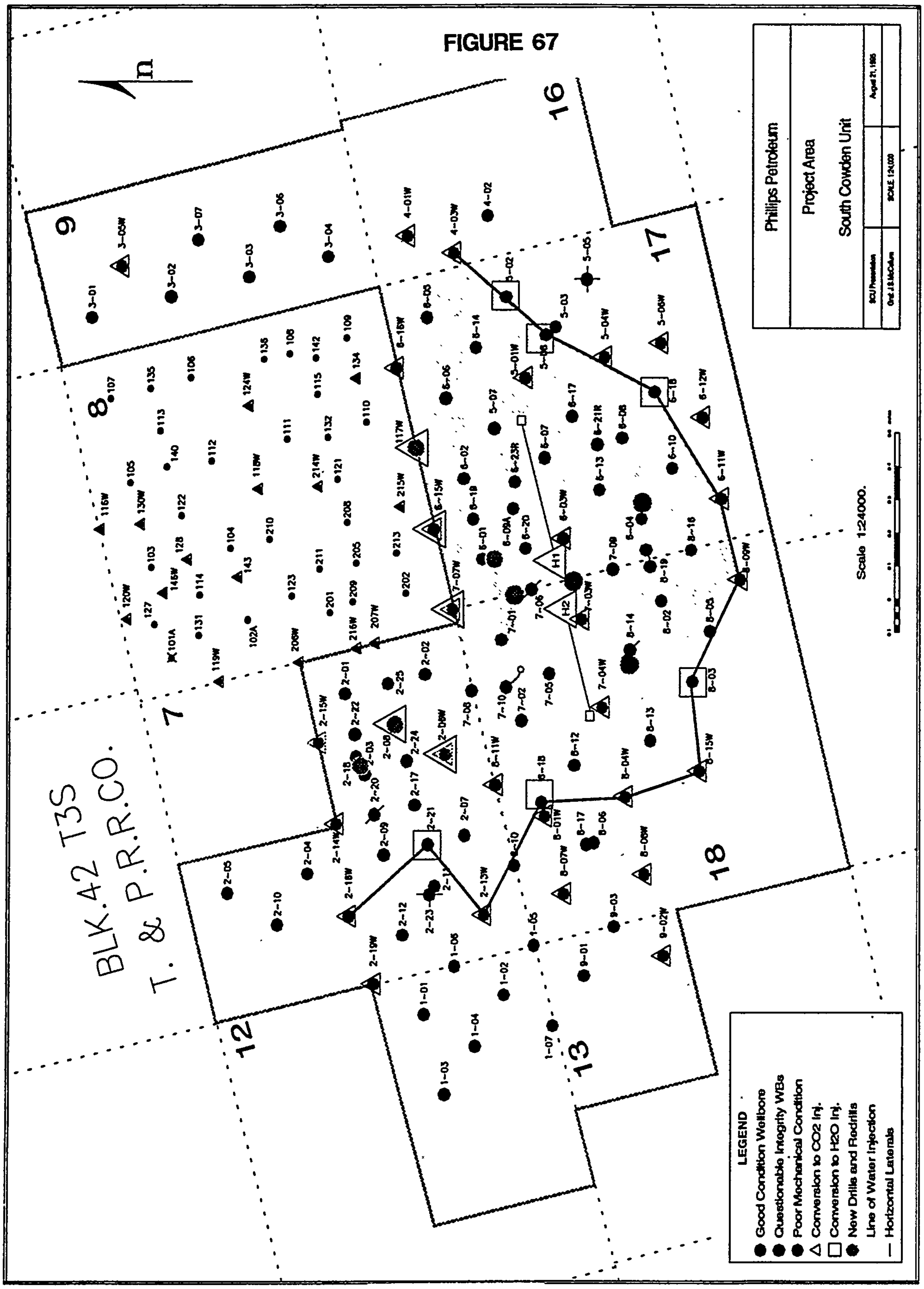

BLK.42 T3S
T. & P.R.R.CO.
Phillips Petroleum
Project Area
South Cowden Unit
Scale 1:24000.
LEGEND
Good Condition Wellbore
Questionable Integrity WBs
Poor Mechanical Condition
Conversion to CO2 Inj.
Conversion to H2O Inj.
New Drills and Redrills
Line of Water Injection
Horizontal Laterals

FIGURE 68

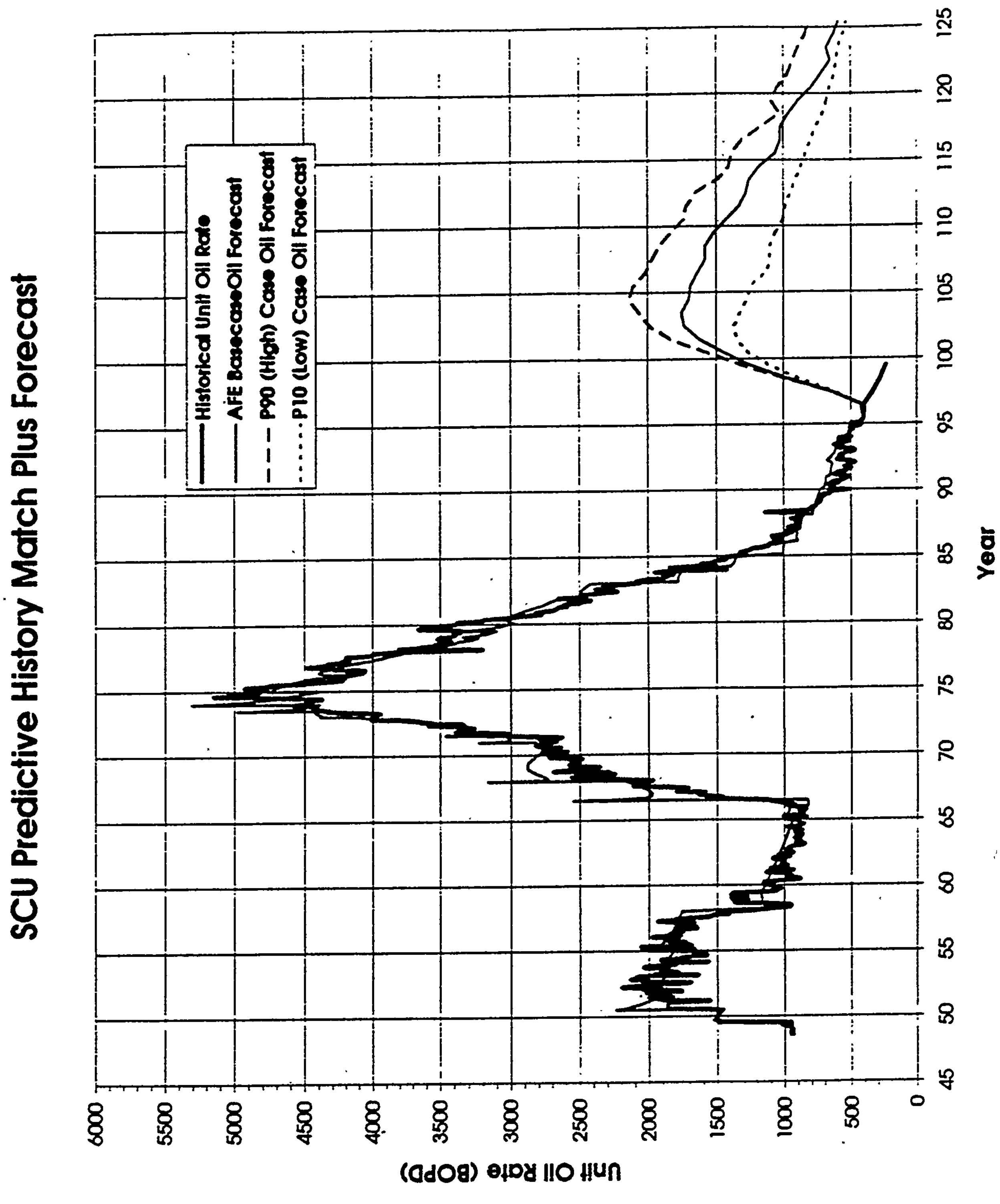

SCU Predictive History Match Plus Forecast
Historical Unit Oil Rate
AFE BasecaseOil Forecast
P90 (High) Case Oil Forecast
P10 (Low) Case Oil Forecast
Unit Oil Rate (BOPD)
Year
6000
5500
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
45
50
55
60
65
70
75
80
85
90
95
100
105
110
115
120
125

FIGURE 69

SCU CO2 PROJECT
OPERATING EXPENSE

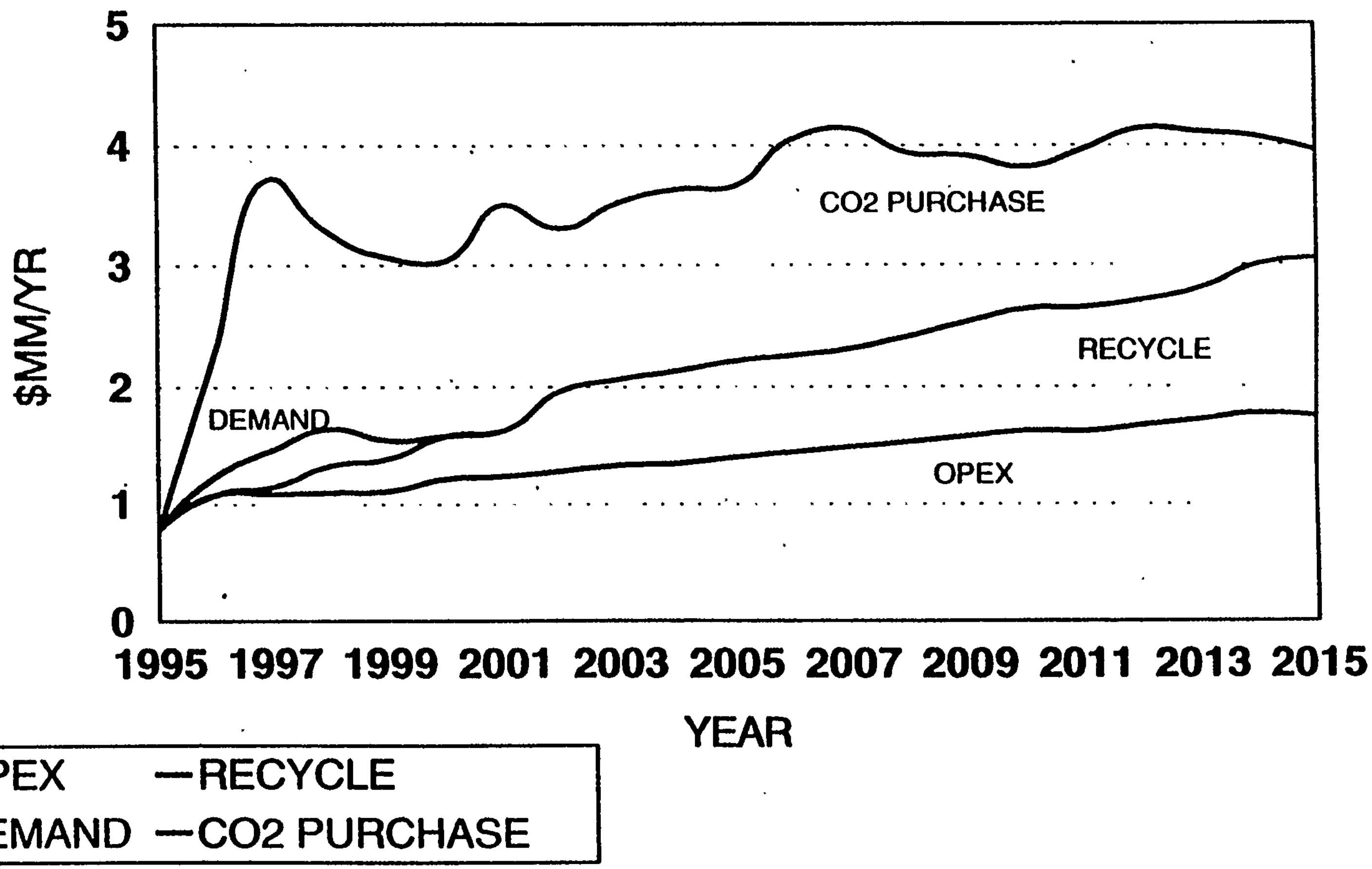


FIGURE 70

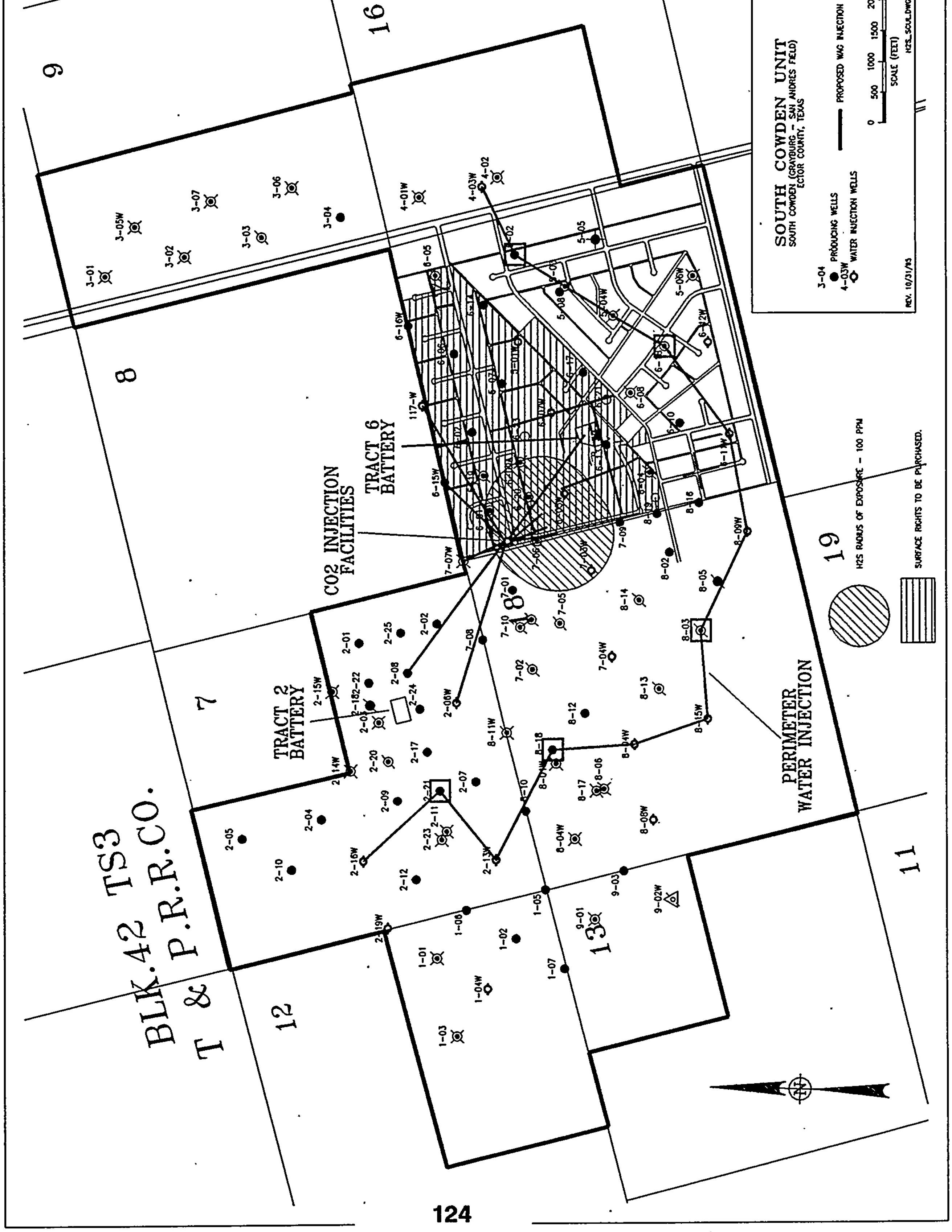
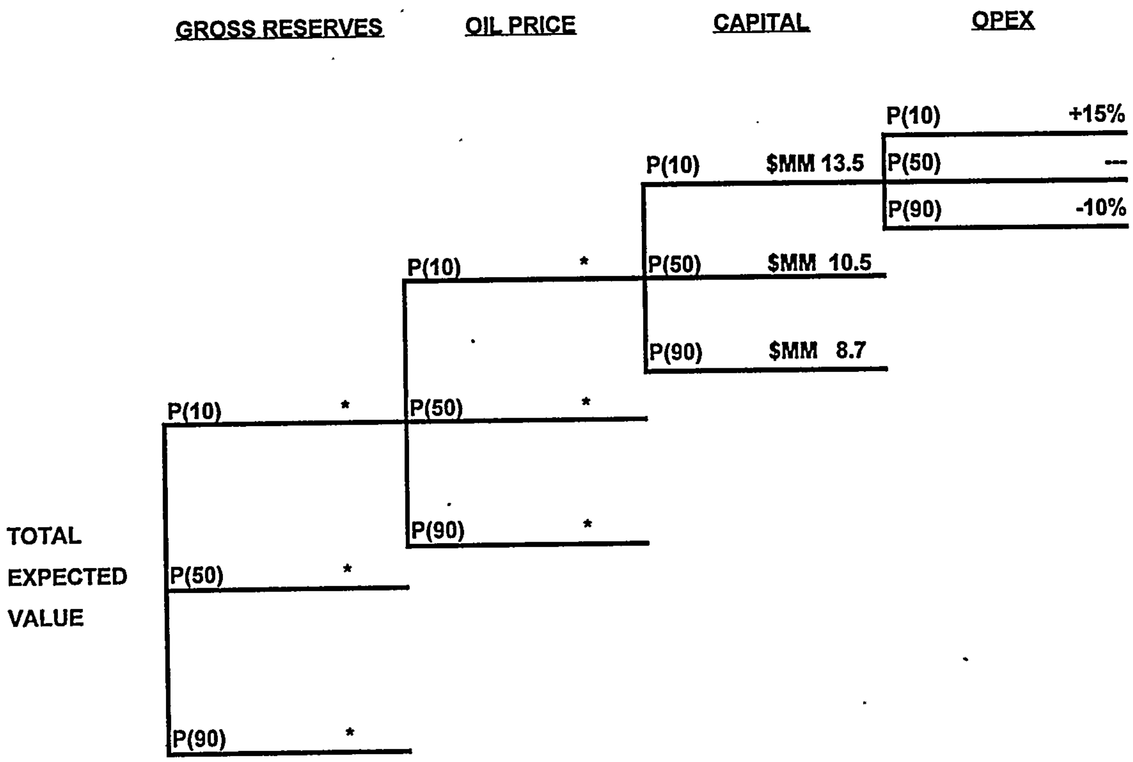

SOUTH COWDEN UNIT
SOUTH COWDEN (GRAYBURG - SAN ANDRES FIELD)
ECTOR COUNTY, TEXAS
PRODUCING WELLS
WATER INJECTION WELLS
PROPOSED WAG INJECTION
0 500 1000 1500 2000
SCALE (FEET)
REV. 10/31/95
H2S RADIUS OF EXPOSURE - 100 PPM
SURFACE RIGHTS TO BE PURCHASED.
BLK. 42 TS3
T & P.R.R.CO.
TRACT 6 BATTERY
CO2 INJECTION FACILITIES
TRACT 2 BATTERY
PERIMETER WATER INJECTION
9
16
8
7
18
19
12
13
11

FIGURE 71

DECISION TREE DESCRIPTION



* - Values not included due to confidential nature.

LIST OF TABLES

TABLES

TABLE I

South Cowden Unit
Injection Surveys

Well No.	TD	Perf/OH	Layer	Date	% Intensity	% Velocity	Date	% Intensity	% Velocity	Date	% Intensity	% Velocity	Date	% Intensity	% Velocity	Date	% Intensity	% Velocity	Date	% Intensity	% Velocity
1W04	4725	OH 4615-4725	Above	5/2/85	6.2	25	5/30/84	12.5	-	5/13/83	55	53	3/30/83			10/23/72	-	41.5	6/12/69		
			G 4645-4664		38.1	21		39.7	-		20	23.6		29	-		-	4.6		-	18.2
			F 4664-4701		55.7	54		47.8	-		21.9	18		32.7	70.8		-	36.7		35.5	50.2
			E 4701-4767								3.1	5.4		38.3	29.2		-	17.2		64.5	31.6
2W06	4685	OH 4480-4685	Above	11/2/84			6/21/84	27	51	8/29/81	32.8	32	10/23/72	-	32	7/21/69			9/2/67		
			G 4508-4522		0	0		0	0		7.2	.8		-	1		0	3.4		-	9.4
			F 4522-4564		21	0		3.9	0		24.6	17		-	6.6		5	1.6		-	8.6
			E 4564-4631		79	100		32.5	23.1		29.4	1.2		-	33.4		42	58.4		-	25.9
			D 4631-4662		0	0		28.7	21.4		6	31.8		-	27		53	36.6		-	56.1
			C 4662					▼ 7.9	▼ 4.5												
2W13	4712	OH 4455-4712	Above	12/12/83	41	84	3/12/83		26	10/24/72	-	12.6	9/3/67								
			G 4608-4619		0	0			▼ 74		-	8.2									
			F 4619-4669		7.5	0		9			-	6.4		-	32						
			E 4669-4738		23.5	6		▼ 91			-	35.8		-	28						
			D 4738		▼ 28	▼ 10					-	▼ 37		-	▼ 40						
2W14	4732	P 4535-4708	Above	8/29/81			10/27/72			6/12/69											
			G 4476-4486																		
			F 4486-4529		51.2	32															
			E 4529-4595		34.8	35					15.7	40									
			D 4595-4624		10.7	2.5		-	22.9		48.3	18									
			C 4624-4643		3.3	27.8		-	13.8		3	4									
			B 4643-4671		-	2.7		-	13.3		20.1	38									
			A 4671					-	50		12.9	-									
2W15	4700	P 4531-4659	Above	9/2/82			2/18/82			10/26/72											
			G 4480-4500																		
			F 4500-4538		43	57		55	54												
			E 4538-4605		18.6	11.8		19	46		-	56									
			D 4605-4637		11.4	10.3		▼ 26	-		-	35.5									
			C 4637-4654		18	17.9					-	8									
			B 4654		9	3					-	0.5									
2W16	4700	P 4524-4666	Above	11/14/84			3/30/83														
			G 4511-4532																		
			F 4532-4563		24.5	6.4		21	42												
			E 4563-4629		67.6	79		79	58												
			D 4629-4657		7.9	14.6															
			C 4657-4669																		
			B 4669																		
2W19	4700	P 4546-4660	Above	2/3/84			12/12/83			3/23/83											
			G 4533-4552		4.9	-		9.6	8.3		13.5	8									
			F 4552-4587		37.2	-		30.1	38.1		22.9	42.2									
			E 4587-4652		57.9	-		60.3	53.6		63.6	49.8									
			D 4652																		
3W05	4747	OH 4604-4747	Above		NO LAYERS																
4W01	4737	OH 4604-4737	Above	2/3/84	73	-	3/30/83	57.9	-												
			G 4685-4715		27	-		37.4	-												
			F 4715					4.7	-												
4W03	4715	P 4695-4699	Above																		
		OH 4700-4715	G 4678		NO INJECTION SURVEYS																
5W01	4780	OH 4468-4780	Above	7/7/92	95.5	84.2	5/13/84	76	85	4/8/83	78.6	89	9/16/71	73.5	82	10/5/67	-	86 7			
			G 4588-4606		4.5	3.8		0	1.7		2	6		2.6	0		-	13 2			
			F 4606-4641			0		15 4	9.7		3.9	1.3		7.8	10.8						
			E 4641-4703			12		8 6	3 6		15 5	3.7		16.1	7.2						

TABLE I

South Cowden Unit
Injection Surveys

Well No.	TD	Perf/OH	Layer	Date	% Intensity	% Velocity	Date	% Intensity	% Velocity	Date	% Intensity	% Velocity	Date	% Intensity	% Velocity	Date	% Intensity	% Velocity	Date	% Intensity	% Velocity
			D 4703																		
5W04	4738	OH 4501-4738	Above	8/8/84	84	76	3/12/83	73	78	10/27/72	-	63									
			G 4659-4680		16	24		27	22		-	4									
			F 4680-4724								-	33									
			E 4724-4784																		
			D 4784																		
5W06	4736	OH 4633-4736	Above	8/7/85			3/29/83	41.6	-	10/29/72											
			G 4657-4672					3.9	-		-	13									
			F 4672		100	100		46.5	-		-	49									
								8	-		-	38									
6W03	4699	OH 4496-4699	Above	7/7/92	84.6	80	3/15/84	18.5	46	8/11/83	26.4	56.4	9/2/67								
			G 4587-4602		2	0		10	0		4	6		-	0						
			F 4602-4640		2.3	5		11.3	24		15.6	11.6		-	16.5						
			E 4640		11.1	15		60.2	30		54	26		-	83.5						
6W07	4759	OH 4464-4759	Above																		
			G 4575-4592		NO INJECTION SURVEYS																
			F 4592-4631																		
			E 4631-4694																		
			D 4694-4720																		
			C 4720-4739																		
			B 4739																		
6W11	4768	OH 4530-4749	Above	11/7/83			8/28/81			9/26/71	22	36.6	5/25/66	-	31.6						
			G 4658-4671								12.2	18.5		-	0.9						
			F 4671-4713		100	100		100	100		17.8	10.9		-	6.5						
			E 4713-4773								20	26		-	30						
			D 4773								28	8		-	31						
6W12	4767	OH 4550-4746	Above	5/30/84	100	100	3/16/84	100	-	3/11/83	100	100									
			G 4690-4702																		
			F 4702-4745																		
			E 4745																		
6W15	4851	P 4560-4718	Above	12/14/83			9/17/82	8.8													
			G 4547-4560		4.6	0		4.2	0												
			F 4560-4609		30.4	43.5		12.1	17.6												
			E 4609-4679		7	8.7		10.9	4.4												
			D 4679-4707		18.2	32.8		19.7	28.8												
			C 4707-4725		24	5.3		44.3	49.2												
			B 4725-4751		6.3	9.7															
			A 4751		9.5																
6W16	4825	P 4630-4724	Above	7/11/84			7/12/83			3/30/83											
			G 4555-4571		0	0		0	0		0	0									
			F 4571-4612		0	0		0	0		0	0									
			E 4612-4685		78	44.8		37.6	47.4		39.5	62									
			D 4685-4715		22	55.2		30.4	40.6		34.6	28.3									
			C 4715-4732					32	12		25.9	9.7									
			B 4732																		
7W03	4690	OH 4532-4677	Above																		
			G 4573-4591		NO INJECTION SURVEYS																
			F 4591-4639																		
			E 4639-4705																		
			D 4705																		

TABLE I

South Cowden Unit
Injection Surveys

Well No.	TD	Perf/OH	Layer	Date	% Intensity	% Velocity	Date	% Intensity	% Velocity	Date	% Intensity	% Velocity	Date	% Intensity	% Velocity	Date	% Intensity	% Velocity	Date	% Intensity	% Velocity
7W04	4695	OH 4536-4695	Above	11/2/84	30.1	15	10/27/83	22	22	10/28/72	-	25	5/27/66								
			G 4605-4619		4.1	7.7		0.3	0		-	0		-	0						
			F 4619-4667		12.8	26.3		21.6	21		-	29.4		-	24.4						
			E 4667-4737		▼ 53	▼ 51		▼ 56.1	▼ 57		-	▼ 45.6		-	▼ 75.6						
			D 4737																		
7W07	4750	P 4592-4707	Above	5/2/85			9/21/71														
			G 4554-4565		0	0		0	0												
			F 4565-4608		13	10		0	0												
			E 4608-4671		▼ 87	54		100	100												
			D 4671-4700			▼ 36															
			C 4700-4718																		
			B 4718																		
8W01	4774	OH 4494-4774	Above																		
			G 4811		NO INJECTION SURVEYS																
8W04	4780	OH 4514-4754	Above	3/16/84	79	100	4/7/83	71.2	99.1	9/21/71	-	86									
			G 4661-4675		21			28.8	0.9		-	14									
			F 4675-4725																		
			E 4725-4797																		
			D 4797																		
8W07	4790	OH 4529-4790	Above	11/3/84			6/21/84	29.1	87	10/27/83	21.5	31.1									
			G 4653-4664					2.9			1.8	4.2									
			F 4664-4711		16.8	51.8		17.4	5.9		14.1	24.2									
			E 4711-4752		83.2	48.2		33.5	6.2		26.6	40.5									
			D 4752					17.1	0.9		▼ 36										
8W08	4789	OH 4549-4789	Above	5/26/66																	
			G 4683-4694																		
			F 4694-4742		3.6	-															
			E 4742		96.4	-															
8W09	4767	OH 4550-4759	Above	7/11/84	90.3	86.4	4/7/83	86.3	85												
			G 4684-4702		9.7	13.6		13.7	15												
			F 4702-4748																		
			E 4748																		
8W11	4760	P 4568-4690	Above	5/13/83																	
			G 4559-4574		9.2	26															
			F 4574-4616		26.8	23.8															
			E 4616-4683		64	50.2															
			D 4683-4712																		
			C 4712-4726																		
			B 4726																		
8W15	4800	P 4693-4791	Above	7/9/85	48.4	35	7/18/74			7/18/74	2.6										
			G 4698-4717		14.6	54.2		5.9	6.8		8	2.7									
			F 4717-4766			4.8		21.7	38.5		16.8	21									
			E 4766		▼ 37	▼ 6		36.4	25.7		34.6	34.3									
								▼ 36	▼ 29		▼ 38	▼ 42									
9W02	4822	OH 4636-4725	Above	7/9/85		NO LAYERS															

TABLE II

LOG INTERPRETATION PARAMETERS

Porosity / Lithology Computation Parameters

Component	RHOB g/cc	Apparent Log Reading NPHI %LS	DT us/ft	U_pe B/cc
Porosity	1.00	100	189	0.4
Dolomite	2.87	2	44	9.0
Sand	2.65	-3	56	4.8
Anhydrite	2.98	-3	50	14.9

Porosity Regression Equations

Compensated Neutron Porosity (Limestone Porosity Units)

PORE = (0.818 * NPHI) - 1.488 $r^2 = 0.762$

Sidewall Neutron Porosity (Limestone Porosity Units)

PORE = (0.771 * SNP) - 0.252 $r^2 = 0.887$

Sonic Travel Time (Microsec/ft)

PORE = (0.878 * DT) - 38.037 $r^2 = 0.753$

TABLE III

SOUTH COWDEN RESERVOIR FLUID COMPOSITION

Normalized Feed Mole Fractions

Component	Number	
N_2	1	0.0047
CO_2	2	0.0066
H_2S	3	0.0209
C_1	4	0.1150
C_2	5	0.0575
C_3	6	0.0704
C_4	7	0.0156
C_4	8	0.0447
IC_5	9	0.0249
C_5	10	0.0239
C_6	11	0.0699
C_{7+}	12	0.5459
	Sum	1.0000

C_{7+} Molecular Weight	228.00
C_{7+} Specific Gravity	0.8784
Reservoir Temperature	98°F

TABLE IV

SOUTH COWDEN 16-COMPONENT EOS FLUID DESCRIPTION

Revised Component Property Data (Field Units):

Component		No.	Mol Weight	Critical Temp. (R)	Critical Pressure (psia)	Acentric Factor	Critical Volume (ft3/mol)	Specific Gravity	Boiling Point (R)	EOS Constant Correction Factors Omega A	Omega B
N2		1	28.01	227.3	493.0	0.0450	1.4427	0.4700	139.3	1.0000	1.0000
CO2		2	44.01	547.6	1070.6	0.2310	1.5051	0.5072	350.4	1.0000	1.0000
H2S		3	34.08	672.4	1306.0	0.1000	1.5641	0.5000	383.1	1.0000	1.0000
C1		4	16.04	343.0	667.8	0.0115	1.5899	0.3300	201.0	1.0000	1.0000
C2		5	30.07	549.8	707.8	0.0908	2.3695	0.4500	332.2	1.0000	1.0000
C3		6	44.10	665.7	616.3	0.1454	3.2499	0.5077	416.0	1.0000	1.0000
IC4		7	58.12	734.7	529.1	0.1756	4.2082	0.5631	470.6	1.0000	1.0000
C4		8	58.12	765.3	550.7	0.1928	4.0803	0.5844	490.8	1.0000	1.0000
IC5		9	72.15	828.8	490.4	0.2273	4.8991	0.6247	541.8	1.0000	1.0000
C5		10	72.15	845.4	488.6	0.2510	4.8702	0.6310	556.6	1.0000	1.0000
C6		11	86.18	913.4	436.9	0.2957	5.9290	0.6640	615.4	1.0000	1.0000
C7+	(F1)	12	100.01	1022.0	461.1	0.2772	6.3118	0.7637	681.4	1.0000	1.0000
C7+	(F2)	13	143.67	1175.7	369.4	0.3953	8.6332	0.8178	822.1	1.0000	1.0000
C7+	(F3)	14	226.56	1367.5	270.7	0.5986	12.8241	0.8705	1018.4	1.0000	1.0000
C7+	(F4)	15	359.06	1557.3	199.3	0.8707	18.1942	0.9181	1228.8	1.0000	1.0000
C7+	(F5)	16	570.00	1740.6	154.3	1.1880	23.6228	0.9642	1436.8	1.0000	1.0000

Revised Component Property Data (SI Units):

Component		No.	Critical Temp. (K)	Critical Pressure (kPa)	Critical Volume (m3/kmol)	Critical Z-factor	Boiling Point (K)	Parachor	Vol.Trans. Shift s=c/b	EOS Zc
N2		1	126.3	3399.1	0.0901	0.2916	77.4	41.0	-0.19300	0.3074
CO2		2	304.2	7381.5	0.0940	0.2742	194.7	70.0	0.09842	0.3074
H2S		3	373.5	9004.6	0.0976	0.2831	212.8	41.0	-0.12900	0.3074
C1		4	190.6	4604.3	0.0993	0.2884	111.7	77.0	-0.15900	0.3074
C2		5	305.4	4880.1	0.1479	0.2843	184.6	108.0	-0.11300	0.3074
C3		6	369.8	4249.2	0.2029	0.2804	231.1	150.3	-0.08600	0.3074
IC4		7	408.1	3648.0	0.2627	0.2824	261.4	181.5	-0.08400	0.3074
C4		8	425.2	3796.9	0.2547	0.2736	272.7	189.9	-0.06700	0.3074
IC5		9	460.4	3381.2	0.3058	0.2701	301.0	225.0	-0.06700	0.3074
C5		10	469.7	3368.8	0.3040	0.2623	309.2	231.5	-0.06100	0.3074
C6		11	507.4	3012.3	0.3701	0.2643	341.9	271.0	-0.03900	0.3074
C7+	(F1)	12	567.8	3179.3	0.3940	0.2654	378.5	312.4	0.01706	0.3074
C7+	(F2)	13	653.2	2546.9	0.5390	0.2528	456.7	430.0	0.04564	0.3074
C7+	(F3)	14	759.7	1866.6	0.8006	0.2366	565.8	630.3	0.07905	0.3074
C7+	(F4)	15	865.1	1374.4	1.1358	0.2170	682.7	887.5	0.08352	0.3074
C7+	(F5)	16	967.0	1064.2	1.4747	0.1952	798.2	1137.7	0.02383	0.3074

Normalized Feed Mole Fractions:

Component		No.	Feed Identifier 1
N2		1	0.0047000
CO2		2	0.0066000
H2S		3	0.0209000
C1		4	0.1150000
C2		5	0.0575000
C3		6	0.0704000
IC4		7	0.0156000
C4		8	0.0447000
IC5		9	0.0249000
C5		10	0.0239000
C6		11	0.0699000
C7+	(F1)	12	0.0915369
C7+	(F2)	13	0.1633763
C7+	(F3)	14	0.1558047
C7+	(F4)	15	0.0972604
C7+	(F5)	16	0.0379218
	Sum:	16	1.0000000

Plus Molecular Weight 228.00
Plus Specific Gravity 0.8784

TABLE V

EOS Predicted vs. Laboratory Measured Phase Properties

	(41 mol% CO2 @ 634 psia) Laboratory Measurement	(41 mol% CO2 @ 634 psia) EOS Prediction	(68 mol% CO2 @ 2514 psia) Laboratory Measurement	(68 mol% CO2 @ 2514 psia) EOS Prediction
$Vr_{HC\text{-}RICH}$	47.4%	49.4%	75%(est.)	79.5%
$\mu_{CO_2\text{-}RICH}$	.017 cp	.015 cp	0.17 cp	0.16 cp
$\mu_{HC\text{-}RICH}$	1.41 cp	1.57 cp	0.54 cp	0.56 cp
$\rho_{CO_2\text{-}RICH}$	0.080 gm/cc	0.081 gm/cc	0.797 gm/cc	0.817 gm/cc
$\rho_{HC\text{-}RICH}$	0.828 gm/cc	0.828 gm/cc	0.846 gm/cc	0.855 gm/cc
$MW_{CO_2\text{-}RICH}$	38.9	38.0	58.2	57.0
$MW_{HC\text{-}RICH}$	128.1	125.2	81.2	83.2
$X_{CO_2/CO_2\text{-}RICH}$	72.3%	69.0%	74.9%	75.5%
$X_{CO_2/HC\text{-}RICH}$	27.7%	31.5%	64.3%	64.2%
$X_{C_{7+}/CO_2\text{-}RICH}$	0.11%	0.08%	10.5%	10.1%
$X_{C_{7+}/HC\text{-}RICH}$	46.1%	42.7%	20.2%	20.1%

TABLE VI

SOUTH COWDEN 8-COMPONENT EOS FLUID DESCRIPTION

Revised Component Property Data (Field Units):

Component	No.	Mol Weight	Critical Temp. (R)	Critical Pressure (psia)	Acentric Factor	Critical Volume (ft3/mol)	Specific Gravity	Boiling Point (R)	---- EOS Constant ---- - Correction Factors - Omega A	Omega B
CO2	1	44.01	547.6	1070.6	0.2310	1.5240	0.5072	350.4	1.0000	1.0000
C1N2	2	17.14	363.6	708.4	0.0336	1.2123	0.3420	216.1	0.9040	0.9966
C2	3	30.07	549.8	707.8	0.0908	1.7597	0.4500	332.2	1.0000	1.0000
C3C5	4	56.44	756.9	547.6	0.1928	3.9078	0.5698	486.3	0.9574	0.9804
C6F1	5	94.02	978.9	451.5	0.2845	7.7368	0.7207	655.2	0.9907	0.9972
F2	6	143.67	1175.7	369.4	0.3953	11.1685	0.8178	822.1	1.0000	1.0000
F3	7	226.56	1367.5	270.7	0.5986	17.4082	0.8705	1018.4	1.0000	1.0000
F4F5	8	418.23	1627.4	182.1	0.9920	29.9614	0.9352	1308.3	0.9567	0.9832

Revised Component Property Data (SI Units):

Component	No.	Critical Temp. (K)	Critical Pressure (kPa)	Critical Volume (m3/kmol)	Critical Z-factor	Boiling Point (K)	Parachor	Vol.Trans. Shift s=c/b	EOS Zc
CO2	1	304.2	7381.5	0.0951	0.2776	194.7	70.0	0.09842	0.3074
C1N2	2	202.0	4884.2	0.0757	0.2201	120.1	76.7	-0.14989	0.3074
C2	3	305.4	4880.1	0.1099	0.2111	184.6	108.0	-0.11300	0.3074
C3C5	4	420.5	3775.6	0.2440	0.2634	270.2	184.0	-0.07343	0.3074
C6F1	5	543.8	3113.0	0.4830	0.3325	364.0	294.5	-0.00641	0.3074
F2	6	653.2	2546.9	0.6972	0.3270	456.7	430.0	0.04564	0.3074
F3	7	759.7	1866.4	1.0868	0.3211	565.8	630.3	0.07905	0.3074
F4F5	8	904.1	1255.5	1.8704	0.3124	726.8	957.7	0.05733	0.3074

Normalized Feed Mole Fractions:

Component	No.	Feed Identifier 1				
CO2	1	0.0275000				
C1N2	2	0.1197000				
C2	3	0.0575000				
C3C5	4	0.1795000				
C6F1	5	0.1614369				
F2	6	0.1633763				
F3	7	0.1558047				
F4F5	8	0.1351822				
Sum:	8	1.0000000				

TABLE VII

Summary of South Cowden CO2 Trapped Gas Coreflood Experiments

Coreflood No.	6
Upstream Core Well	6-23
Downstream Core Well	6-23
Upstream Core Facies	Chaotic
Downstream Core Facies	Chaotic
Upstream Core Depth (ft)	4709.9
Downstream Core Depth (ft)	4709.6
Live Oil Injection	
Ko (live oil) @ Swi (md) *	7.67
Brine Flood 1	
Kw @ Sorw (md)	1.24
Krw @ Sorw (md)	0.162
CO2 Injection	
Kco_2 @ Sorm (md)	0.81
$Krco_2$ @ Sorm (md)	0.106
Sorm (% PV)	4.26
Brine Flood 2	
Kw @ Sgtrap (md)	0.90
Krw @ Sgtrap (md)	0.118
Trapped Gas Saturations	
Sgtrap (% PV) - high est.	32.2
Sgtrap (% PV) - low est.	28.1
Sgtrap (% PV) - average est.	30.2

* Used as the reference (denominator) in relative permeability calculations.

Table VIII.
So. Cowden Water Analyses

Water Sample	%TDS	Na	K	Ca	Mg	Sr	Cl	SO_4
	ppm							
Tract 2-Trans, Pump	7.27	22800	388	2500	619	55.8	36200	3593
Tract 6-FWKO	7.84	25100	441	2490	633	55.0	39900	3238
Tract 6-IPD	7.84	25200	513	2490	650	55.3	39400	3237
Tract 6-FWKO (Aerated and filtered)	7.72	24900	442	2420	636	53.4	40500	4173

Table IX.
Polymer and Crosslinker Systems

OFXC®1163 (American Cyanamid)	High Molecular Weight (10-15x10^6) Anionic (5-7 mole%) Polyacrylamide in Emulsion
Alcoflood® 254S (Allied Colloids)	Low Molecular Weight (3-5x10^5) Anionic (5 or <5mole%) Polyacrylamide, A Solid Product
Zirtech® LA110 (Benchmark R&T)	Organically Complexed Zirconium Compound in Aqueous Solution
RIX:98 (Benchmark R&T)	Organically Complexed Titanium Compound in Aqueous Solution
Water-Cut®684 (Tiorco, Inc.)	Organically Complexed Chromium(III) Compound in Aqueous Solution

Table X.
Bulk Gel Test With OFXC®1163 and Zirtech® LA110 in Aerated FWKO Water at 120°F

Polymer Concn. ppm	Zr Concn. ppm	0hr	1hr	2hr	3.4hr	4.5hr	24hr	15d	224d
		Tongue Length (TL), cm							
5000	250	T	PG	7.0	6.0	5.3	4.7	4.8	4.7
5000	500	T	PG	6.4	4.8	4.4	3.2	2.5	2.2
5000	750	T	PG	8.3	6.4	5.6	3.3	2.2	1.7
5000	1000	T	PG	PG	7.6	6.8	4.6	2.6	1.2
5000	1500	T	SG	PG	PG	8.2	5.1	3.3	0.9
5000	2000	T	VT	SG	PG	PG	6.8	3.6	2.9

NG= No gel, T= Thick, VT= Very thick, SG= Slight gel, PG= Partial gel

Table XI.
Bulk Gel Test With OFXC®1163 and Zirtech® LA110 in Aerated and pH Adjusted (4.2) FWKO Water at 120° F

Polymer Concn. ppm	Zr Concn. ppm	0hr	1hr	2.6hr	4.2hr	5.4hr	22.6hr	13.9d	206d
		Tongue Length (TL), cm							
5000	250	T	6.7	4.4	3.7	3.1	3.0	2.0	1.8
5000	500	T	PG	5.5	4.5	4.0	2.9	1.8	2.7
5000	750	T	PG	6.6	5.1	4.5	3.1	1.8	1.3
5000	1000	T	PG	8.2	6.5	5.1	3.6	1.8	0.7
5000	1500	T	PG	PG	PG	7.8	5.2	2.9	3.5
5000	2000	T	SG	PG	PG	PG	6.5	4.0	4.2

NG= No gel, T= Thick, VT= Very thick, SG= Slight gel, PG= Partial gel

Table XII.
Comparison of Bulk Gels Prepared With 5000 ppm Polymer and 500 ppm Zr in So. Cowden Water With Those Prepared in NBU and C. B. Long Waters at 120° F

Polymer/X-linker/Water	0hr	1hr	2hr	3hr	4hr	24hr	
	Tongue Length (TL), cm						
OFXC®/LA110/FWKO	T	PG	6.4	4.8	4.4	3.2	2.5(15d)
OFXC®/LA110/FWKO (pH 4.2)	T	PG	5.5	--	4.5	2.9	1.8(13d)
OFXC®/LA110/NBU TB-57	T	3.9	3.2	--	2.4	2.2	1.6(6d)
OFXC®/LA110/CBLong(pump dis.)	T	4.1	2.2	2.1	--	1.8	1.2(6d)

NG= No gel, T= Thick, VT= Very thick, SG= Slight gel, PG= Partial gel

Table XIII.
Bulk Gel Test With Alcoflood®254S and Zirtech® LA110 in Aerated and pH Adjusted (4.2) FWKO Water at 120° F

Polymer Concn. ppm	Zr Concn. ppm	0hr	1hr	2.6hr	4.2hr	5.4hr	22.7hr	13.9d	206d
		Tongue Length (TL), cm							
20000	250	NG	NG	NG	NG	T	T	4.0	0.9
20000	500	NG	NG	NG	NG	T	T	1.5	0.7
20000	750	NG	NG	NG	NG	NG	T	1.7	0.7
20000	1000	NG	NG	NG	NG	NG	T	2.8	0.6
20000	1500	NG	NG	NG	NG	NG	NG	8.0	0.7
20000	2000	NG	NG	NG	NG	NG	NG	S-PG	0.5

NG= No gel, T= Thick, VT= Very thick, SG= Slight gel, PG= Partial gel

Table XIV.
Bulk Gel Test With Alcoflood®254S and Zirtech® LA110 in Aerated and pH Adjusted (4.2) FWKO Water at 120°F

Polymer Concn. ppm	Zr Concn. ppm	0hr	1hr	3hr	4.4hr	6.5hr	23hr	13d	196d
		Tongue Length (TL), cm							
30000	250	NG	NG	NG	NG	T	S-PG	2.3	0.7
30000	500	NG	NG	NG	NG	T	S-PG	0.8	0.7
30000	750	NG	NG	NG	NG	T	SG	0.8	0.8
30000	1000	NG	NG	NG	NG	T	T	1.0	0.7
30000	1500	NG	NG	NG	NG	T	T	2.7	0.8
30000	2000	NG	NG	NG	NG	T	T	7.9	0.6

NG= No gel, T= Thick, VT= Very thick, SG= Slight gel, PG= Partial gel

Table XV.
Gel Stability Tests at 98° F Under 2000 psi Pressure of CO_2

Gel System	Cross-linker Concn. ppm	%Gel Strength Before Exposure to CO_2	%Gel Strength After Exposure to CO_2
1%OFXC® 1163 and Zr in pH unadjusted FWKO water	250	70	70
	500	93	93
	750	98	98
	1000	98	98
	1500	97	97
2%Alcoflood®254S and Cr pH adjusted (4.2) FWKO water	250	95	95
	500	97	97
	750	98	98
	1000	98	98
	1500	97	97

TABLE XVI

SCHEDULE OF WORK
(WELLS)

		EXPENDITURE,$M (x 10^3)
1995		
•	DRILL WELL RC-3 (6-24)	$350
1996		
•	DRILL WELLS H-1 AND H-2	$3,870
•	DRILL VERTICAL WAG INJECTOR 206C (2-26W)	
•	DRILL 2 LEASELINE VERTICAL WAG INJECTORS 707 AND M17C	
•	EQUIP 615W AS WAG INJECTOR	
•	DRILL PRODUCING WELLS 798, 7-12, 6-22 & 799	
•	REACTIVATE PRODUCERS 705 AND 620	
•	CONVERT TO WATER INJECTION WELLS 2-21, 8-18, 8-03, 6-18 AND 5-02	
1997		
•	REACTIVATE 6-16W AS LEASELINE WATER INJECTOR	$510
•	REACTIVATE PRODUCERS 6-19, 7-02, 7-08 AND 8-13	
•	DRILL VERTICAL WAG INJECTOR 208C (2-27W)	
1998		
•	DRILL PRODUCING WELLS 203A AND 699	$720
•	REACTIVATE PRODUCERS 2-20 AND 6-05	
1999+		
•	DRILL 4 REPLACEMENT PRODUCERS (LOCATIONS TO BE DETERMINED)	$1,210
•	CONVERT TO WAG INJECTION: RC-3 & 224C	
	TOTAL	$6,660

TABLE XVII

SCHEDULE OF WORK (FACILITIES)

		EXPENDITURE,$M (x 10^3)
1995		
●	PURCHASE LAND AND BUILD FENCE	$320
1996		
●	CONSTRUCT INJECTION FACILITIES	$2,390
●	START BATTERY MODIFICATIONS	
●	PREPARE FOR COMPRESSION	
●	REPLACE WATER INJECTION SYSTEM	
●	INSTALL CATHODIC PROTECTION	
●	START AUTOMATION INSTALLATION	
1997		
●	CONTINUE BATTERY MODIFICATIONS	$250
●	START FLOWLINE REPLACEMENT	
●	CONTINUE AUTOMATION INSTALLATION	
1998		
●	FINISH BATTERY MODIFICATION	$450
	CONTINUE FLOWLINE REPLACEMENT	
●	UPGRADE COMPRESSION	
●	CONTINUE AUTOMATION	
1999+		
●	FINISH FLOWLINE REPLACEMENT	$300
	FINISH AUTOMATION INSTALLATION	
	TOTAL	$3,710

TABLE XVIII

South Cowden CO2

Investment Summary
(Unescalated Gross)

Year	Well Costs	CO2 Facilities	Production Facilities	Flowlines	Compression Installation	Land Acquistion	Replace W.I. Lines	Cathodic Protection	Automation	Total Investments	DOE Share Investments
1996	$4,221.82	$662.91	$203.00	$75.30	$555.00	$322.30	$395.24	$405.90	$87.00	$6,928.47	$2,224.73
1997	$511.51		$30.00	$142.24	$1.00			$0.00	$79.53	$764.28	$245.41
1998	$721.54		$180.00	$142.24	$50.00				$79.53	$1,173.31	$376.75
1999	$607.61			$142.22					$79.53	$829.36	$266.31
2000	$303.81			$0.00	$25.00					$328.81	
2001	$303.81									$303.81	
2002					$50.00					$50.00	
2003										$0.00	
2004										$0.00	
2005										$0.00	
2006										$0.00	
2007										$0.00	
2008										$0.00	
2009										$0.00	
2010										$0.00	
2011										$0.00	
2012										$0.00	
2013										$0.00	
2014					$25.00					$25.00	
2015										$0.00	
2016										$0.00	
2017										$0.00	
2018										$0.00	
2019										$0.00	
2020										$0.00	
2021										$0.00	
2022					$15.00					$15.00	
2023										$0.00	
2024										$0.00	
2025										$0.00	
TOTAL	$6,670.10	$662.91	$413.00	$502.00	$721.00	$322.30	$395.24	$405.90	$325.59	$10,418.04	$3,113.20

TABLE XIX

South Cowden CO2

Expense Summary
(Unescalated Gross)

Year	Total CO2 Cost	DOE Share CO2	Recycle Costs	DOE Share Recycle	Project Area Well Count	Project Area Well Cost	Other SCU Well Count	Other SCU Well Cost	Total Lease Expense	Total Minus CO2 Expense
1996			$0.00	$0.00	34	$782.00	13	$299.00	$1,081.00	$1,081.00
1997			$61.20	$19.65	34	$782.00	12	$276.00	$1,058.00	$1,119.20
1998			$214.66	$68.93	34	$782.00	11	$253.00	$1,035.00	$1,249.66
1999			$249.80	$80.21	34	$782.00	10	$230.00	$1,012.00	$1,261.80
2000			$318.41		34	$860.20	9	$207.00	$1,067.20	$1,385.61
2001			$331.74		34	$860.20	8	$184.00	$1,044.20	$1,375.94
2002			$556.44		34	$860.20	8	$184.00	$1,044.20	$1,600.64
2003			$575.35		34	$860.20	8	$184.00	$1,044.20	$1,619.55
2004			$591.02		33	$834.90	8	$184.00	$1,018.90	$1,609.92
2005			$593.10		33	$834.90	8	$184.00	$1,018.90	$1,612.00
2006			$578.60		33	$834.90	8	$184.00	$1,018.90	$1,597.50
2007			$569.60		33	$834.90	8	$184.00	$1,018.90	$1,588.50
2008			$590.50		33	$834.90	8	$184.00	$1,018.90	$1,609.40
2009			$618.49		33	$834.90	8	$184.00	$1,018.90	$1,637.39
2010			$635.68		33	$834.90	8	$184.00	$1,018.90	$1,654.58
2011			$628.64		31	$784.30	8	$184.00	$968.30	$1,596.94
2012			$617.87		31	$784.30	8	$184.00	$968.30	$1,586.17
2013			$626.93		31	$784.30	8	$184.00	$968.30	$1,595.23
2014			$688.22		31	$784.30	8	$184.00	$968.30	$1,656.52
2015			$709.48		30	$759.00	8	$184.00	$943.00	$1,652.48
2016			$660.14		29	$733.70	8	$184.00	$917.70	$1,577.84
2017			$657.18		29	$733.70	8	$184.00	$917.70	$1,574.88
2018			$674.72		28	$708.40	8	$184.00	$892.40	$1,567.12
2019			$683.56		28	$708.40	8	$184.00	$892.40	$1,575.96
2020			$700.55		27	$683.10	8	$184.00	$867.10	$1,567.65
2021			$673.28		25	$632.50	8	$184.00	$816.50	$1,489.78
2022			$417.28		25	$632.50	8	$184.00	$816.50	$1,233.78
2023			$397.63		24	$607.20	8	$184.00	$791.20	$1,188.83
2024			$397.37		23	$581.90	8	$184.00	$765.90	$1,163.27
2025			$383.96		22	$556.60	8	$184.00	$740.60	$1,124.56
TOTAL	*	*	$15,401.41			$22,887.30		$5,865.00	$28,752.30	$44,153.71
	* - Confidential Information									

FORCE FIELD EVALUATION

TABLE XX

Forces Pushing for CO2 Flood	**Forces Against CO2 Flood**
Improved Recovery, additional booked reserves which cannot be added any other way. Relatively low risk reserves.	Higher operating costs due to CO_2 purchases and recycle costs resulting in lower margins.
Extended field life which allows recovery of additional waterflood reserves which would have been abandoned.	Capital requirements to implement CO_2 injection and maintain SCU operations for an additional 20-30 years.
Proven success at EVGSAU operating a profitable CO_2 flood. Second highest IBRT property in PPC.	Project uncertainty with development concept of horizontal injection wells.
Innovative CO_2 supply contract which is tied to future oil prices for escalation factors.	Technical manpower commitments to PPC for maintenance of CO_2 flood operations.
Possible Emmons Unit cooperation and/or acquisition resulting in additional reserves and lowering of SCU project cost.	
DOE contribution to project capital and expenses. ($6.1 million)	

LIST OF APPENDIX

Appendix	Description
I	Drilling and Completion Premises
II	Production Facilities Upgrade Premises
III	Water Injection Facilities Premises
IV	CO_2 Injection Facilities Premises
V	Facilities Compression Premises
VI	Water Disposal Premises
VII	Facilities Automation Premises
VIII	Electrical Premises
IX	Risk Assessment
X	Facilities Land Purchase Premises
XI	Facilities Cathodic Protection Premises

APPENDIX

APPENDIX I

DRILLING AND COMPLETION PREMISES

DRILLING AND COMPLETION PREMISES

Multiple wells will be drilled and reactivated as a result of the CO_2 project. The drilling and completion premises are written for the following scenarios:

1) Drill open-hole horizontal WAG injector
   a) 2400' lateral
   b) 1650' lateral

2) Drill cased-hole horizontal WAG injector
   a) For informational purposes only

3) Drill vertical WAG injector

4) Drill well #RC-3 (cored producer)

5) Drill producer

6) Deepen current water injector

7) Reactivation of TA'd producers

8) Conversion of current producers to water injection

9) Conversion of TA'd producers to water injection

Surplus equipment units that are currently in the field will be used on new drilled wells and reactivations. The first five reactivations in 1996 and 1997 already have pumping units on site. These reactivations include well numbers 7-05, 6-20, 6-19, 7-02 and 8-13.

SCU CO_2 Project
2400' Horizontal WAG Injector Premise
August 24, 1995

1) Exact location and azimuth will be determined after examining core from RC3.

2) Drill 12-1/4" surface hole with fresh water/native mud.

3) Set 9-5/8", 36.0 lb/ft, H-40 ST&C surface casing at 1450'.

4) Cement 9-5/8" surface casing to surface.

5) Drill 8-3/4" hole with 10 ppg brine to 4580' TVD/4798' MD.

6) Set 7", 20.0 lb/ft, J-55 ST&C production casing at 4580' TVD/4798' MD.

7) Cement 7" production casing to surface. Run temperature survey if cement does not circulate.

8) Drill 6-1/8" open-hole to 4675' TVD/8755' MD with 10 ppg brine and starch to control fluid loss to 15 cc or less.

9) Well will be equipped with a 3000 psi wellhead meeting NACE Standard MR-01-75.

10) Well will be mud logged.

11) CNL/LDT logs will be ran.

12) Well will be stimulated with 25,000 gallons of 20% NeFe HCl acid through coiled tubing.

13) 3-1/2" tbg with Rice Duoline 20 fiberglass lining will be set at 4775'.

14) A temperature and full bore spinner on coil tubing will be utilized for injection surveys.

15) Cathodic protection equipment will be installed.

HORIZONTAL DRILLING TIME ESTIMATE

PHILLIPS PETROLEUM CO.
SOUTH COWDEN UNIT
ECTOR COUNTY, TEXAS

DATE: JUNE 19, 1995

DEPTH INTERVAL	SECTION	BHA	PROPOSED BIT	EST. ROP FT./HR.	DRILLING HOURS	TRIP HOURS	CIRC. HOURS	RMNG/CO SURV. HO	TOTAL HOURS	STD-BY HOURS
0 TO 4106	Gyro wellbore	RIG DC'S			6 days				0.0	24.0
4106 TO 4798	Drill Curve w/ avg. BUR @ 12 deg./100' to83 deg. incl.	6-3/4" M1C DA Set @1.7 6-1/2" NMDC	2X 8-3/4" ATJ-33	28	24.7	5.0	2.0	6.0	37.7	0.0
4798 TO 4800	Run & cmt. 7" casing NU, test and drill out	3-1/2" HWDP	1X 6-1/8" Mill Tooth						0.0	48.0
4800 TO 8755	BUR 8 deg./100' to @ 90 deg. incl. and 0 deg. AZ.	4-3/4" M1C AK SET @ 1.2 4-3/4" NMDC	2X 6-1/8" ATJ-33	32	123.6	21.0	6.0	30.0	180.6	0.0
					DRILLING HOURS	TRIP HOURS	CIRC. HOURS	RMNG/CO SURV HOU	TOTAL HOURS	STD-BY HOURS
				TOTAL	148.3	26.0	8.0	36.0	218.3	72.0

*TTL DRLG DAYS	:	10.0
TTL STAND-BY DAYS:		3.0
TTL JOB DAYS	:	13.0

*THE TOTAL DRILLING DAYS INCLUDES A 10% CONTINGENCY FACTOR.

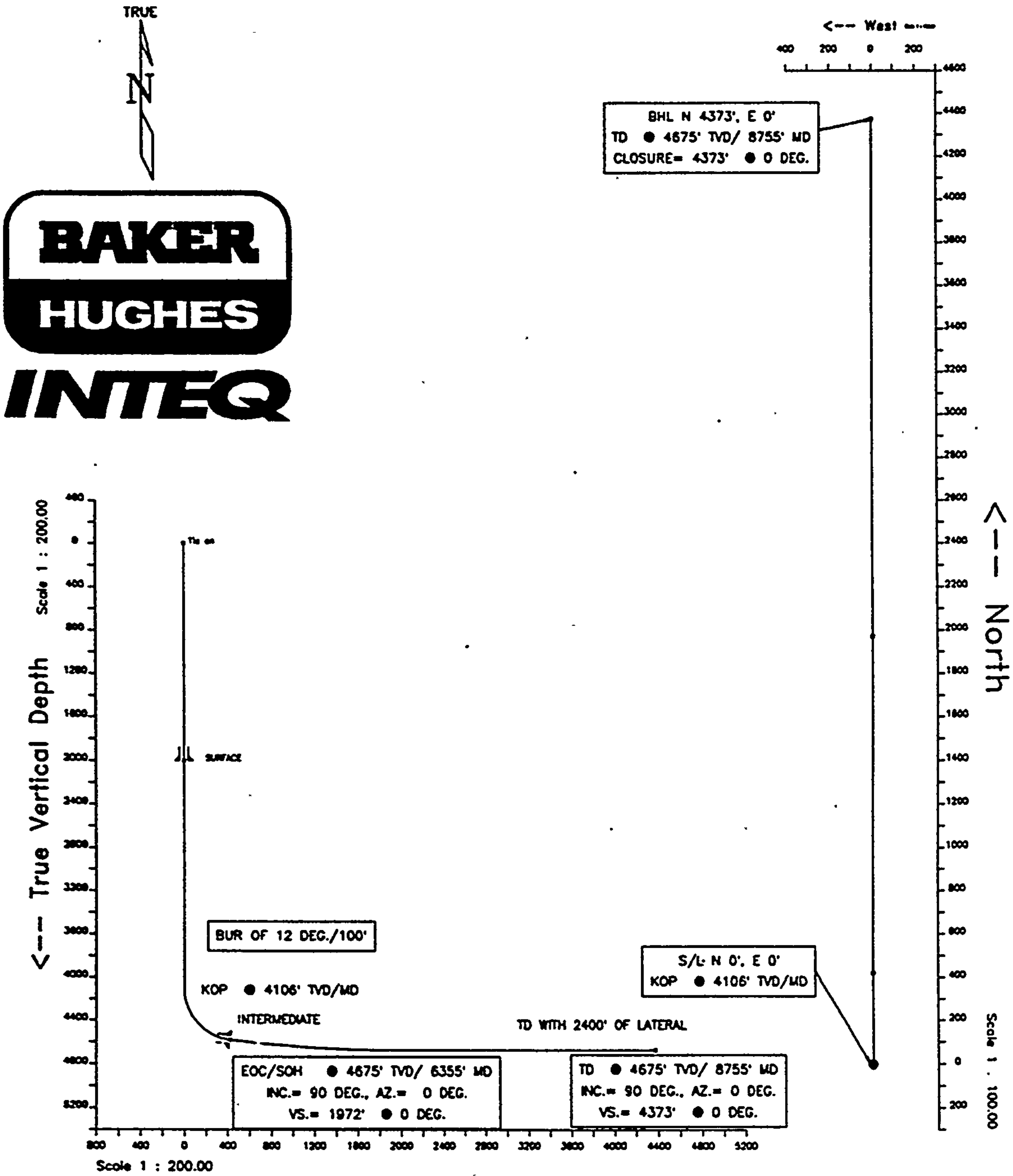
PHILLIPS

Structure : SOUTH COWDEN UNIT

Field : FOSTER   Location : ECTOR COUNTY, TEXAS

---- WELL PROFILE DATA ----

Point	MD	Inc	Dir	TVD	North	East	Deg/100
Tie on	0	0.00	0.00	0	0	0	0.00
End of Hold	4106	0.00	0.00	4106	0	0	0.00
End of Build	4796	83.00	0.00	[illegible]	419	0	12.00
End of Build	6355	90.00	0.00	4675	1972	0	[illegible]
End of Hold	8755	90.00	0.00	4675	4373	0	0.00



Scale 1 : 200.00

Vertical Section on 0.00 azimuth with reference 0.00 N, 0.00 E from slot #1

SCU CO_2 Project
1650' Horizontal WAG Injector Premise
August 24, 1995

1) Exact location and azimuth will be determined after examining core from RC3.

2) Drill 12-1/4" surface hole with fresh water/native mud.

3) Set 9-5/8", 36.0 lb/ft, H-40 ST&C surface casing at 1450'.

4) Cement 9-5/8" surface casing to surface.

5) Drill 8-3/4" hole with 10 ppg brine to 4580' TVD/4798' MD.

6) Set 7", 20.0 lb/ft, J-55 ST&C production casing at 4580' TVD/4798' MD.

7) Cement 7" production casing to surface. Run temperature survey if cement does not circulate.

8) Drill 6-1/8" open-hole to 4675' TVD/8005' MD with 10 ppg brine and starch to control fluid loss to 15 cc or less.

9) Well will be equipped with a 3000 psi wellhead meeting NACE Standard MR-01-75.

10) Well will be mud logged.

11) CNL/LDT logs will be ran.

12) Well will be stimulated with 20,000 gallons of 20% NeFe HCl acid through coiled tubing.

13) 3-1/2" tbg with Rice Duoline 20 fiberglass lining will be set at 4775'.

14) A temperature and full bore spinner on coil tubing will be utilized for injection surveys.

15) Cathodic protection equipment will be installed.

HORIZONTAL DRILLING IME ESTIMATE

PHILLIPS PETROLEUM CO.
SOUTH COWDEN UNIT
ECTOR COUNTY, TEXAS

DATE: JUNE 19, 1995

BAKER HUGHES INTEQ

DEPTH INTERVAL	SECTION	BHA	PROPOSED BIT	EST. ROP FT./HR.	DRILLING HOURS	TRIP HOURS	CIRC. HOURS	RMNG/CO SURV. HO	TOTAL HOURS	STD-BY HOURS
0 TO 4106	Gyro wellbore	RIG DC'S			6 days				0.0	24.0
4106 TO 4798	Drill Curve w/ avg. BUR @ 12 deg./100' to 83 deg. incl.	6-3/4" M1C DAM Set @1.7 6-1/2" NMDC	1X 8-3/4" ATJ-33	28	24.7	5.0	2.0	6.0	37.7	0.0
4798 TO 4800	Run & cmt. 7" casing NU, test and drill out	3-1/2" HWDP	1X 6-1/8" Mill Tooth						0.0	48.0
4800 TO 8005	BUR 8 deg./100' to @ 90 deg. incl. and 0 deg. AZ.	4-3/4" M1C AKO SET @ 1.2 4-3/4" NMDC	2X 6-1/8" ATJ-33	32	100.2	12.0	4.0	18.0	134.2	0.0

	DRILLING HOURS	TRIP HOURS	CIRC. HOURS	RMNG/CO SURV HOU	TOTAL HOURS	STD-BY HOURS
TOTAL	124.9	17.0	6.0	24.0	171.9	72.0

*TTL DRLG DAYS :	7.9
TTL STAND-BY DAYS:	3.0
TTL JOB DAYS :	10.9

*THE TOTAL DRILLING DAYS INCLUDES A 10% CONTINGENCY FACTOR.

PHILLIPS

ucture : SOUTH COWDEN UNIT

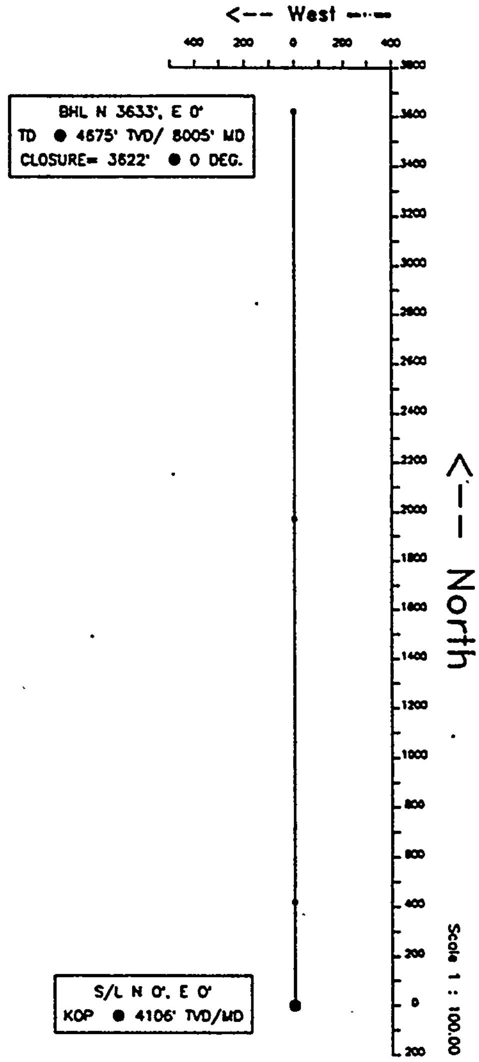
Field : FOSTER Location : ECTOR COUNTY, TEXAS

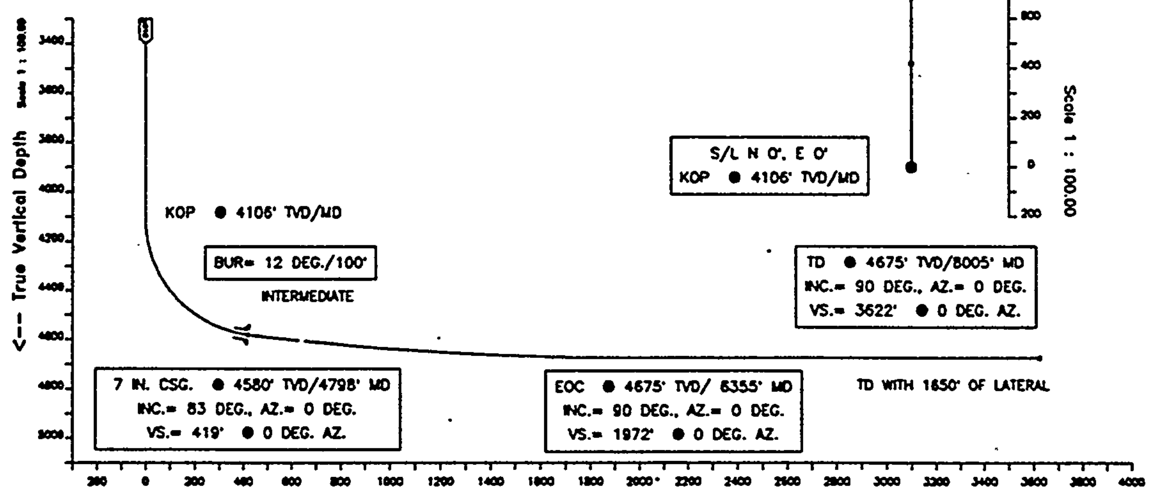
WELL PROFILE DATA

Point	MD	Inc	Dir	TVD	North	East	Deg/100
Tie on	0	0.00	0.00	0	0	0	0.00
End of Hold	4106	0.00	0.00	4106	0	0	0.00
End of Build	4798	83.00	0.00	4580	419	0	12.00
End of Build	6355	90.00	0.00	4675	1972	0	0.46
End of Hold	8005	90.00	0.00	4675	3622	0	0.00

TRUE N

BAKER HUGHES INTEQ





Scale 1 : 100.00

Vertical Section on 0.00 azimuth with reference 0.00 N, 0.00 E from slot #1

SCU CO_2 Project
1650' Horizontal WAG Injector with liner Premise
August 24, 1995

1) Exact location and azimuth will be determined after examining core from RC3.

2) Drill 12-1/4" surface hole with fresh water/native mud.

3) Set 9-5/8", 36.0 lb/ft, H-40 ST&C surface casing at 1450'.

4) Cement 9-5/8" surface casing to surface.

5) Drill 8-3/4" hole with 10 ppg brine to 4580' TVD/4798' MD.

6) Set 7", 20.0 lb/ft, J-55 ST&C production casing at 4580' TVD/4798' MD.

7) Cement 7" production casing to surface. Run temperature survey if cement does not circulate.

8) Drill 6-1/8" open-hole to 4675' TVD/8005' MD with 10 ppg brine and starch to control fluid loss to 15 cc or less.

9) Set 4-1/2", 9.5 lb/ft, J-55 ST&C liner from TD to 4758' MD.

10) Two rigid turbolating centralizers will be placed on each joint of 4-1/2" casing.

11) Cement liner with 90 sacks of foam cement (Class C + 2% $CaCl_2$ + 0.8 gal/sk Howco Suds + 0.4 gal/sk foam stabilizer). The cement is foamed with 350 ft^3/bbl nitrogen to give a slurry density of 10 ppg.

12) Well will be equipped with a 3000 psi wellhead meeting NACE Standard MR-01-75.

13) Well will be mud logged.

14) CNL/LDT logs will be ran.

15) Perforate first 1000' with five 150' 1 spf intervals with 50' gaps for packer setting. Perforate last 600' with four 100' 2 spf intervals with 50' gaps for packer setting. (**Note:** Perfs will be picked after well is logged.)

16) 993.53303 RDX 32 gram explosive charges will be used. Concrete target data shows 0.43" entry hole diameter and 30.46" penetration.

17) Well will be stimulated with 20,000 gallons of 20% NeFe HCl acid through coiled tubing.

18) 3-1/2" tbg with Rice Duoline 20 fiberglass lining will be set at 4775'.

19) A temperature and full bore spinner on coil tubing will be utilized for injection surveys.

20) Cathodic protection equipment will be installed.

NOTE: For informational purposes only. Both horizontal wells are premised to be completed with an open hole.

SCU CO_2 Project
Vertical WAG Injector Premise
August 24, 1995

1) Drill 11" surface hole with fresh water/native mud.

2) Set 8-5/8", 24.0 lb/ft, K-55 ST&C surface casing at 1450'.

3) Cement 8-5/8" surface casing to surface.

4) Drill 7-7/8" hole with 10 ppg brine to 4500'. Mud up at 4500' with starch to control fluid loss to 15 cc or less.

5) Set 5-1/2", 15.5 lb/ft, K-55 ST&C production casing at 4900'.

6) Cement 5-1/2" production casing to surface. Run temperature survey if cement does not circulate.

7) Well will be equipped with a 3000 psi wellhead meeting NACE Standard MR-01-75.

8) CNL/LDT & DLL/MSFL logs will be ran.

9) Perforate 50' at 1 spf with 22.7 gm charges. Perfs will be picked off of logs.

10) Well will be stimulated with 5,000 gallons of 20% NeFe HCl acid.

11) 2-7/8" tbg with Rice Duoline 20 fiberglass lining or an equivalent IPC lining will be set 30' above top perf.

12) Cathodic protection equipment will be installed.

SCU CO_2 Project
Well #RC3 Premise
August 24, 1995

1) Drill proir to spudding of two horizontal WAG injectors.

2) Drill 11" surface hole with fresh water/native mud.

3) Set 8-5/8", 24.0 lb/ft, K-55 ST&C surface casing at 1450'.

4) Cement 8-5/8" surface casing to surface.

5) Drill 7-7/8" hole with 10 ppg brine to 4500'. Mud up at 4500' with starch to control fluid loss to 15 cc or less.

6) 250' of conventional core will be cut in the San Andres formation. Estimated core interval is from 4570' to 4820'.

7) Set 5-1/2", 15.5 lb/ft, K-55 ST&C production casing at 4900'.

8) Cement 5-1/2" production casing to surface. Run temperature survey if cement does not circulate.

9) Well will be equipped with a 3000 psi wellhead meeting NACE Standard MR-01-75.

10) CNL/LDT & DLL/MSFL logs will be ran.

11) Perforate 50' at 1 spf with 22.7 gm charges. Perfs will be picked off of logs.

12) Well will be stimulated with 5,000 gallons of 20% NeFe HCl acid.

13) RIH with 1 jt. bull-plugged tbg, perforated sub, seating nipple, 300' of tbg, tubing anchor, and 2-7/8" 6.5 lb/ft J-55 production tubing. Set SN at 4700'± and tubing anchor at 4400'±.

14) Cathodic protection equipment will be installed.

SCU CO_2 Project
Producer Premise
August 24, 1995

1) Drill 11" surface hole with fresh water/native mud.

2) Set 8-5/8", 24.0 lb/ft, K-55 ST&C surface casing at 1450'.

3) Cement 8-5/8" surface casing to surface.

4) Drill 7-7/8" hole with 10 ppg brine to 4500'. Mud up at 4500' with starch to control fluid loss to 15 cc or less.

5) Set 5-1/2", 15.5 lb/ft, K-55 ST&C production casing at 4900'.

6) Cement 5-1/2" production casing to surface. Run temperature survey if cement does not circulate.

7) Well will be equipped with a 2000 psi wellhead meeting NACE Standard MR-01-75.

8) CNL/LDT & DLL/MSFL logs will be ran.

9) Perforate 50' at 1 spf with 22.7 gm charges. Perfs will be picked off of logs.

10) Well will be stimulated with 5,000 gallons of 20% NeFe HCl acid.

11) RIH with 1 jt. bull-plugged tbg, perforated sub, seating nipple, 300' of tbg, tubing anchor, and 2-7/8" 6.5 lb/ft J-55 production tubing. Set SN at 4700'± and tubing anchor at 4400'±.

12) Surplus pumping units within the unit will be utilized.

13) Cathodic protection equipment will be installed.

SCU CO_2 Project
Injection Well Deepening Premise
August 24, 1995

1) Deepen two off-structure wells for increased water injection capacity.

2) The four candidates (4-03, 6-11, 6-12, 8-09) are presently 4-1/2" open-hole completions.

3) POOH with injection tubing and packer.

4) MIRU air drilling equipment and deepen well another 500' with a 4-1/2" bit.

5) RDMO air drilling equipment and RIH with injection tubing and packer.

6) Clean well with 1500 gallon acid job.

7) Return well to water injection.

SCU CO_2 Project
TA'd Well Reactivation Premise
August 24, 1995

1) Reactivate seven temporarily abandoned producers.

2) Five of the seven reactivations currently have pumping units on site (7-05, 6-20, 6-19, 7-02 & 8-13).

3) Depending on the condition, surplus rods & tubing within the unit could be used in the reactivations. Three of the proposed reactivations (7-05, 6-19 & 8-13) currently have rods & tubing in the hole and three of the proposed conversions to water injection (2-21, 8-18 & 5-02) also have rods & tubing in the hole.

4) The reactivations will consist of drilling out the CIBP and cleaning up the well with a small acid job.

5) RIH with rods and tubing.

6) Return well to pumping.

SCU CO_2 Project
Water Injection Conversion Premise
August 24, 1995

1) Convert three producers and two TA'd producers to water injection.

2) POOH with rods and tubing (2-21 & 8-18).

3) POOH with tubing and submersible pump (5-02).

4) Drill out CIBP (6-18 & 8-03).

5) RIH with IPC injection tubing and packer.

6) Clean well with 1500 gallons acid job.

7) Put well on water injection.

8) Move pumping units to new drilled wells 604-A and 799.

APPENDIX II

PRODUCTION FACILITIES UPGRADE PREMISES

PREMISE - SCU - UPGRADE PRODUCTION FACILITIES

Tract 6 Battery

Current vessel sizing will handle the predicted volumes of fluid.

Year 1 Modifications

* 3 Infrared CO_2 Gas Analysis meters to be installed - one on each test system, and one on the re-injected gas stream, prior to recompression.
* 4 H2S monitors to be installed.

Year 2 Modifications

* VRU to be upgraded to compress vapors to 50 psia. Cost includes new compressor, changing to jacket water cooled (radiator, thermostat, etc.), 25 hp motor (using current starter), plus electrical and welding contract labor (3 hours each).

Year 3 Modifications

* 2 - 125# FWKO and heater treaters to be installed. These are REPLACEMENT equipment for the battery, and were included due to the uncertainty of the remaining life of the current vessels.

Tract 2 Battery

Year 1 Modifications

* 2 - CO_2 gas analysis meters to be installed - one on each test system.
* Tract 2 to become satellite - tankage and LACT not to be used.
  Two lines to continue between Tract 2 and Tract 6. One is the current water transfer line that is currently in place. The 4" water injection line (which is being replaced with fiberglass) will be rerouted to Tract 2.
* Undetermined number of wells to be routed from Tract 2 to Tract 6. If a well (due to breakthrough, high gas volume) becomes difficult to separate at Tract 2, it will be rerouted to Tract 6 when needed.

Year 3 Modifications

* IF pressure and volume cause it to be necessary, a 125# treater will be installed at Tract 2.
* IF pressure and volume cause it to be necessary, a 6" buried Drisco line will be

installed between Tract 2 and Tract 6 to handle additional fluid or gas volume.

Flowlines

Flowlines are replaced over a three year period, beginning in Year 2. Lines are replaced with 2-3/8", J-55 coated with either TK-70 or Corvell 1660.

Lines in the unpurchased residential area will be buried. Lines in the purchased area will be laid on surface and will be as straight as practical (IE - not having to be laid in alleyways.

Flowlines will be replaced as pressure response is seen.

APPENDIX III

WATER INJECTION FACILITIES PREMISES

WITH 1 ATTACHMENT

REPLACEMENT OF EXISTING WATER INJECTION SYSTEM, LAY WATER INJECTION LINES, & INSTALL RUNS TO FIVE NEW CONVERSIONS AT SOUTH COWDEN UNIT CO_2 PROJECT

INJECTION SYSTEM

- Ditch and lay approximately 5,200 ft. of 4 in., 3,300 ft. of 3 in., 1,700 ft. of 2-7/8 in., and 16,900 ft. of 2 in. to a total of twelve (12) wells. All pipe to be 2000 PSI rated fiberglass line pipe.

- All pipelines to be buried with a minimum of 36 in. cover.

- Install three (3) 4 in., two (2) 3 in., and twelve (12) 2 in. ANSI 900 - 1500 fiberglass flanges.

- Install 2000 PSI rated fiberglass tee's as follows:

  A) One (1) 4 in. x 4 in. x 4 in.

  B) Two (2) 4 in. x 4 in. x 2-7/8 in.

  C) One (1) 4 in. x 4 in. x 2 in.

  D) One (1) 2-7/8 in. x 2-7/8 in. x 2 in.

  E) Four (4) 3 in. x 3 in. x 2 in.

  F) Four (4) 2 in. x 2 in. x 2 in.

- Install 2000 PSI rated fiberglass nipples as follows:

  A) Three (3) 4 in. x 1 ft. long

  B) Five (5) 3 in. x 1 ft. long

  C) Fourteen (14) 2 in. x 1 ft. long

  D) Twelve (12) 2 in. x 6 ft. long

- Install fourteen (14) 2 in., 2000 PSI rated fiberglass 45° fittings.

- Install three (3) 2 in., 2000 PSI rated fiberglass 90° fittings.

- Block Valve Settings:

A) One (1) 4 in. block valve setting consisting of:

1) Valve, Gate, 4 in. Aluminum Bronze, ANSI 900, RF.

2) Approximately 16 ft. of 4 in. Sch. 80 Line Pipe.

3) Four (4) Flanges, 4 in. CS, Weld Neck, ANSI 1500, RF, w/Sch. 80 Bore.

4) Four (4) 4 in. Sch. 80, CS, Weld-end 45° fittings.

5) 4 in. x 1/2 in. Thread-O-Let.

6) Valve, Ball, 1/2 in., SS (2500 PSI).

B) One (1) 3 in. block valve setting consisting of:

1) Valve, Gate, 3 in., Aluminum Bronze, ANSI 900, RF.

2) Approximately 16 ft. of 3 in. Sch. 80, Line Pipe.

3) Four (4) Flanges, 3 in., CS, Weld Neck, ANSI 1500, RF, w/Sch. 80 Bore.

4) Four (4) 3 in. Sch. 80, CS, Weld-end 45° fittings.

5) 3 in. x 1/2 in. Thread-O-Let.

6) Valve, Ball, 1/2 in., SS (2500 PSI).

C) One (1) 2-7/8 in. block valve setting consisting of:

1) Valve, Gate, 2-7/8 in., ANSI 900, RF.

2) Approximately 16 ft. of 2-7/8 in. Sch. 80, Line Pipe.

3) Four (4) Flanges, 2-7/8 in. CS, Weld Neck, ANSI 1500, RF, w/Sch. 80 Bore.

4) Four (4) 2-7/8 in. Sch. 80, CS, Weld-end 45° fittings.

5) 2-7/8 in. x 1/2 in. Thread-O-Let.

6) Valve, Ball, 1/2 in., SS (2500 PSI).

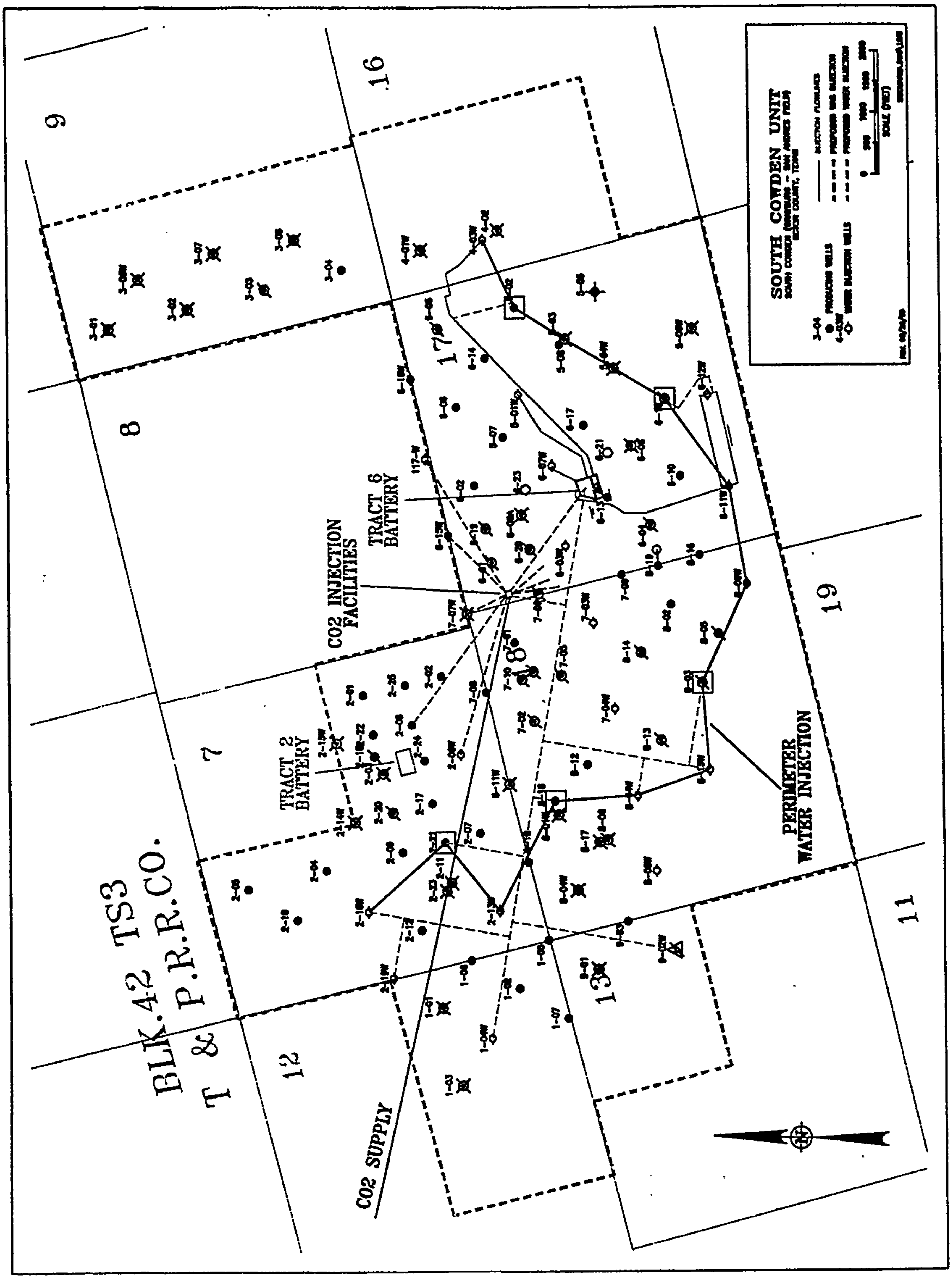
- Install water injection meter runs on five (5) new conversion wells Nos. 2-21, 8-18, 8-03, 6-18, and 5-02; each consisting of:

1) 12 ft. of 1 in. Nominal, Sch. 80, SS, Smls.

2) Valve, Gate, 3000 PSI, 1 in. Aluminum Bronze.

3) Meter, Turbine, 1 in. x 1 in. Halliburton Union w/Magnetic Pickup.

4) Strainer, 1 in. 3000 PSI, Aluminum Bronze, w/316 SS, 20 Mesh Screen.


SOUTH COWDEN UNIT
BLK.42 TS3
T & P.R.R.CO.
CO2 SUPPLY
TRACT 2 BATTERY
CO2 INJECTION FACILITIES
TRACT 6 BATTERY
PERIMETER WATER INJECTION
9
16
8
17
7
18
19
12
13
11

APPENDIX IV

CO_2 INJECTION FACILITIES PREMISES

WITH 3 ATTACHMENTS

WAG DISTRIBUTION & INJECTION SYSTEMS PREMISES FOR SOUTH COWDEN UNIT CO_2 PROJECT

WAG DISTRIBUTION SYSTEM

- Ditch and lay approximately 11,600' of 2 in. 2000 LP Fiberglass line pipe w/T&C couplings, and approximately 1,700' of 2-1/2 in. 2000 LP Fiberglass line pipe w/T&C couplings to eight (8) WAG Injection wells. All fiberglass to be manufactured by Fiber Glass Systems, Inc. (STAR). Anticipated wellhead pressure to be a maximum of 1500 psi.

  All pipelines to be buried with a minimum of 36 in. cover.

- Install sixteen (16) 2 in. 900 - 1500 ANSI 8rd Fiberglass flanges.

- Install eight (8) 2 in. x 1 ft. long 2000 LP Fiberglass nipples.

WAG INJECTION METER RUNS

- Install eight (8) 316L Stainless Steel Injection Meter Runs; each consisting of:

  A) Approximately 36 ft. of 2 in. nominal, Sch. 80, 316L SS Smls.

  B) Thirteen (13) Flanges, Weld Neck, 2 in., ANSI 1500, RTJ, WN, Sch. 80 bore, 316L SS.

  C) Valve, Ball 2 in., ANSI 900, RTJ, Regular Port, SS body, w/SS trim.

  D) Choke, 2 in., ANSI 900, RTJ, Taylor 316 SS body and intervals, 316 SS Defuser Basket, two (2) 3/8 in. Ceramic Discs, 90 Durometer Peroxide Cured Buna-N O-Rings, w/120V Actuator and Basket.

  E) Valve, Check, Swing, 2 in., ANSI 900, RTJ, all 316 SS w/Teflon Seats.

  F) Strainer, 2 in., 3000 psi, SW, 316L SS body, 316 SS 20 Mesh Screen.

  G) Meter, Turbine, 1 in. x 2 in. Halliburton EZ-IN BF, ANSI 1500 w/Hardware Kit and Magnetic Pickup. (The two (2) horizontal wells require 1.5 in. x 2 in..)

H) Valve, Relief, 1/2 in. x 1 in., 316 SS, set at 1750 psi.

I) Pressure Transmitter.

J) Three (3) 1/2 in. SS Ball Valves (2500 psi).

K) Two (2) 2 in. x 1/2 in. 316 SS Thread-O-Lets.

L) Six (6) 1/2 in. x 4 in. SS Schedule 160 Nipples.

M) Two (2) 2 in. 316 SS Weld 45°, Sch. 80.

N) 1/2 in. x 1/2 in. X 1/2 in. Threaded SS X-Heavy Tee.

- Install eight (8) Injection Run Assemblies at Wellhead; each consisting of:

A) Approximately 25 ft. of 2 in. Nominal, Sch. 80, 316L SS Smls.

B) Four (4) Flanges, Weld Neck, 2 in., ANSI 1500, RTJ, WN, Sch. 80 Bore, 316L SS.

C) Valve, Check, Swing, 2 in., ANSI 900, RTJ, all 316 SS w/Teflon Seats.

D) Valve, Ball, 2 in., ANSI 900, RTJ, Regular port, SS body, w/ SS trim.

E) 1/2 in. x 2 in. Thread-O-Let, 316 SS.

F) 1/2 in. SS Ball Valve (2500 psi).

G) Two (2) 2 in. 316 SS, Weld 45°, Sch. 80.

- Install WAG Field Header approx. 2000' North of Tract Six Battery.

A) CO_2 Manifold consisting of:

1) Approximately 50 ft. of 4 in. Sch. 80 Line Pipe, CS .45 CE or less.

2) Eight (8) Reducing Weld Tees, X-Heavy CS 4 in. x 4 in. x 2 in., with .45 CE or less.

3) Eight (8) Flanges, 2 in. CS, ANSI 1500, with Sch. 80 Bore, RTJ, .45 CE or less.

4) Eight (8) Valves, Ball, 2 in., ANSI 900, RTJ, Regular Port, CS, Nace Trim.

5) Eight (8) Flanges, 4 in. CS, Weld Neck, ANSI 1500, RTJ, w/Sch. 80 Bore, .45 CE or less.

6) Two (2) 4 in. CS, ANSI 1500, Blind Flange, RTJ, .45 CE or less.

7) Weld Tee, 4 in. x 4 in. x 4 in. CS, Sch. 80, .45 CE or less.

8) Weld-O-Let, 4 in. x 2 in. CS.

9) Three (3) Flanges, CS, ANSI 1500, RTJ, Sch. 80 Bore, .45 CE or less.

10) Valve, 1/2 in., Needle, CS, ANSI 1500, Regular Port.

11) Valve, Relief, 1 in. x 1/2 in., CS, set at 1750 psi.

12) 2 in. x 1/2 in. Thread-O-Let, CS.

13) Valve, Ball, 1/2 in., CS, 2500 psi.

14) To be Stress Relieved after Shop Fabrication.

B) H_2O Manifold, consisting of:

1) Approximately 900 ft. of 4 in. 2000 LP Fiberglass Line Pipe w/T&C Couplings.

2) Approximately 50 ft. of 4 in. Sch. 80 Line Pipe, IPC.

3) Eight (8) Reducing Weld Tees, X-Heavy 4 in. x 2 in., IPC.

4) Eight (8) Flanges, 2 in., Weld Neck, ANSI 1500, Sch. 80 Bore, RF, IPC.

5) Eight (8) Valves, Gate, 2 in., ANSI 900, RF, Aluminum Bronze Body, SS Trim.

6) Eight (8) Flanges, 4 in., Weld Neck, Sch. 80 Bore, ANSI 1500 RF, IPC.

7) Two (2) Flanges, Blind, CS, ANSI 1500, RF, IPC.

8) Tee, 4 in. x 4 in. x 4 in., Weld Neck, X-Heavy, CS, IPC.

9) To be Internally Plastic Coated after Shop Fabrication.

C) CO_2 Purchase Valve Setting:

1) Approximately 70 ft., 4 in., Sch. 80, CS, Line Pipe, .45 CE or less.

2) Five (5) Flanges, 4 in., Weld Neck, Sch. 80 Bore, CS, RTJ, .45 CE or less.

3) Valve, 4 in., ESD, ANSI 900, RTJ, 416 SS, Nace Trim, Fail Close Actuator.

4) Valve, Ball, 4 in., ANSI 900, RTJ, Regular Port, CS, Nace Trim.

5) Transmitter, Temperature.

6) Transmitter, Pressure.

7) Valve Relief, 1 in. x 1/2 in., Set at 1750 PSI.

8) Three (3) Thread-O-Let, 1/2 in., CS, .45 CE or less.

9) Ten (10) Nipples, 1/2 in. x 4 in., CS, Sch. 160, .45 CE or less.

10) Four (4) Valves, Ball, 1/2 in., CS, 2500 psi.

11) Four (4) 4 in. Weld 45°, CS, X-Heavy, .45 CE or less.

12) To be Stress Relieved after Shop Fabrication.

D) Compressor Valve Setting (CO_2):

1) Approximately 2090 ft. of 4 in., Sch. 80, CS, Line Pipe, .45 CE or less.

2) Five (5) Flanges, 4 in., Weld Neck, Sch. 80 Bore, ANSI 1500 RTJ, CS, .45 CE or less.

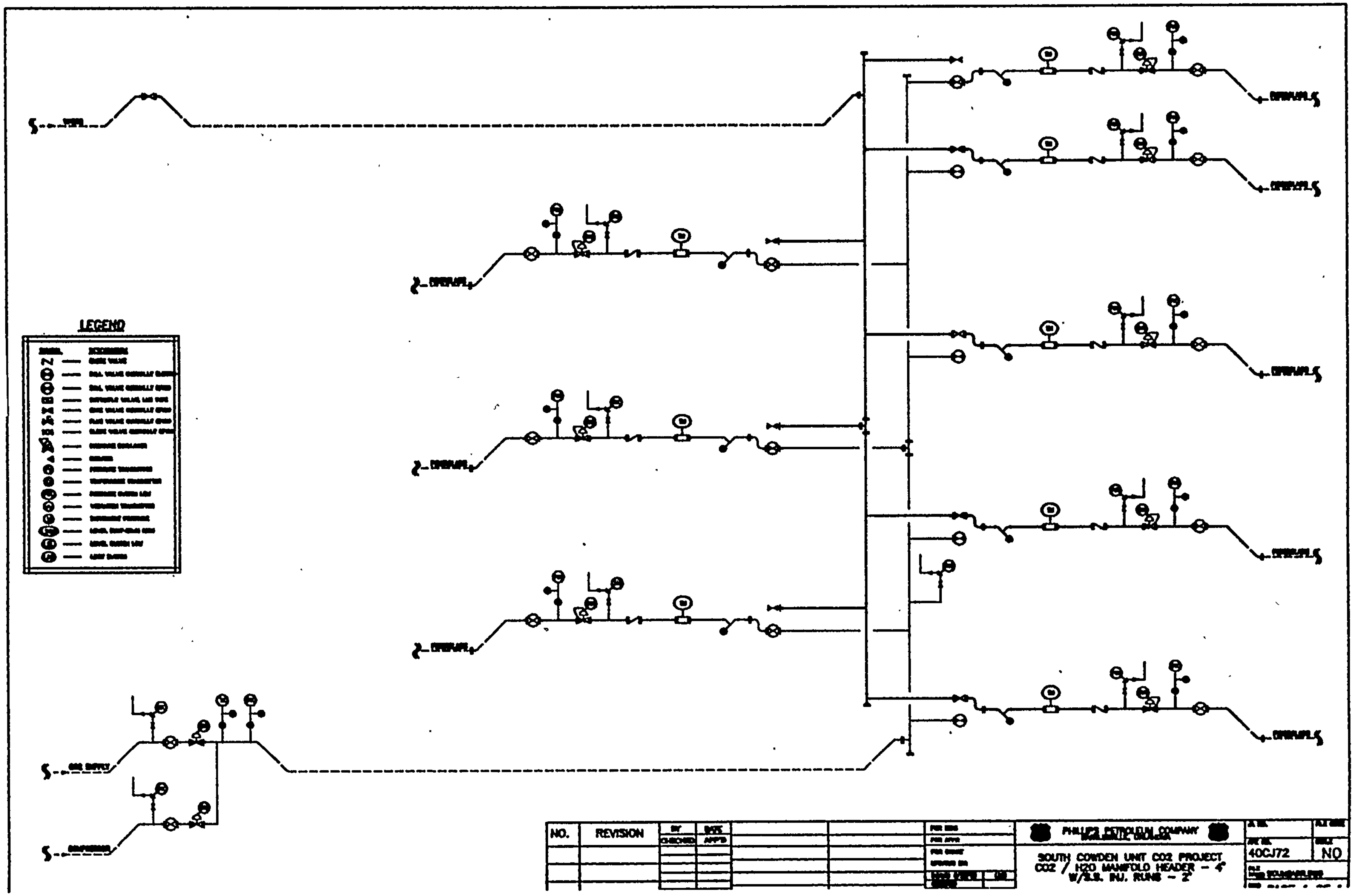
3) Tee, 4 in. x 4 in. x 4 in. Weld Neck, CS, X-Heavy, .45 CE or less.

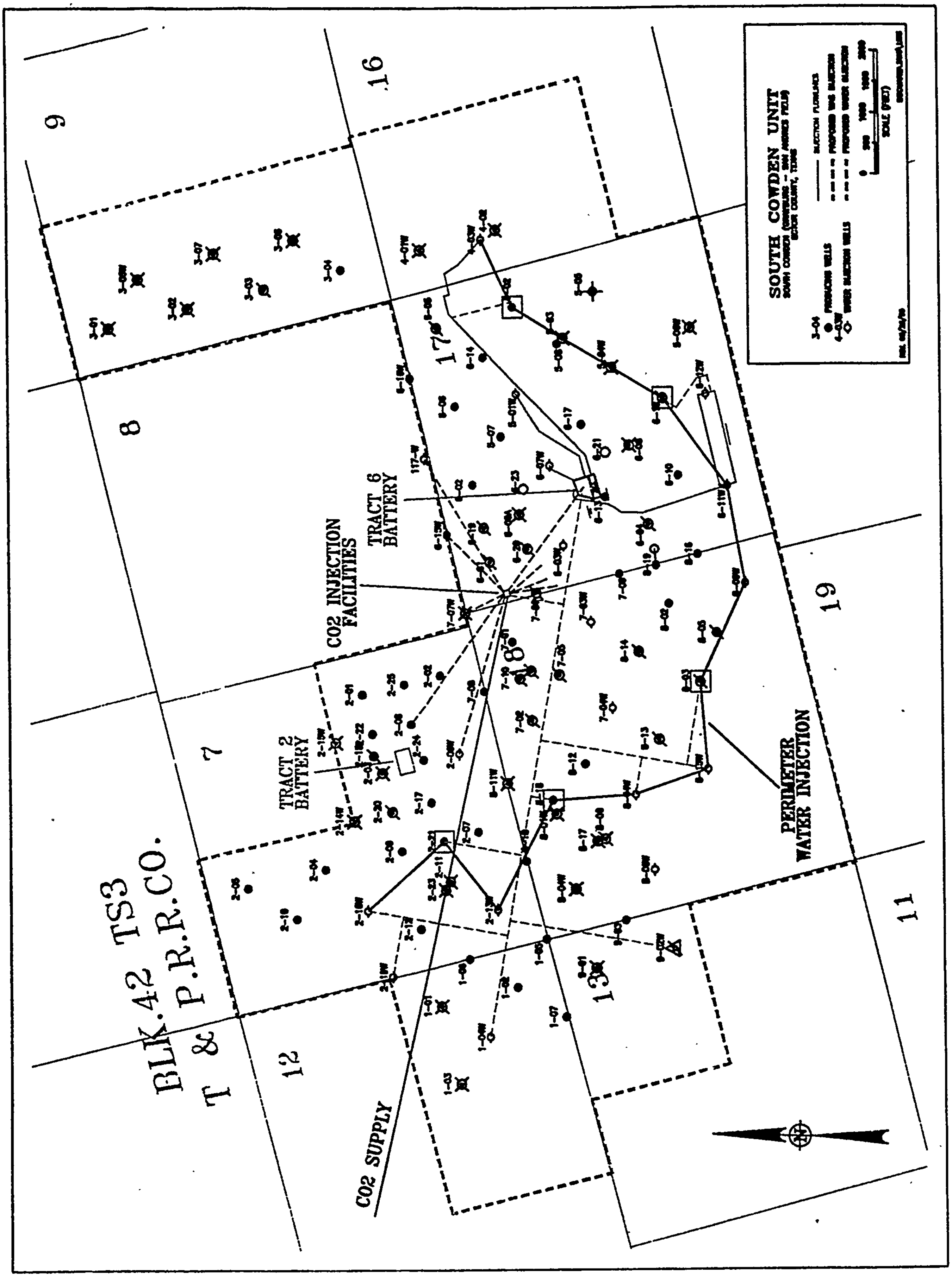
4) Valve, 4 in., ESD, 416 SS, ANSI 900, RTJ, Nace Trim, Fail Close Actuator.

5) Valve, 4 in., Ball, ANSI 900, RTJ, Regular Port, CS, Nace Trim.

6) Weld 90°, CS, X-Heavy, .45 CE or less.

7) To be Stress Relieved in Field after Fabrication.


LEGEND
NO.
REVISION
PHILLIPS PETROLEUM COMPANY
SOUTH COWDEN UNIT CO2 PROJECT
CO2 / H2O MANIFOLD HEADER - 4"
W/S.S. INJ. RUNS - 2"
40CJ72
NO



BLK.42 TS3
T & P.R.R.CO.
SOUTH COWDEN UNIT
CO2 INJECTION FACILITIES
TRACT 6 BATTERY
TRACT 2 BATTERY
PERIMETER WATER INJECTION
CO2 SUPPLY
9
16
8
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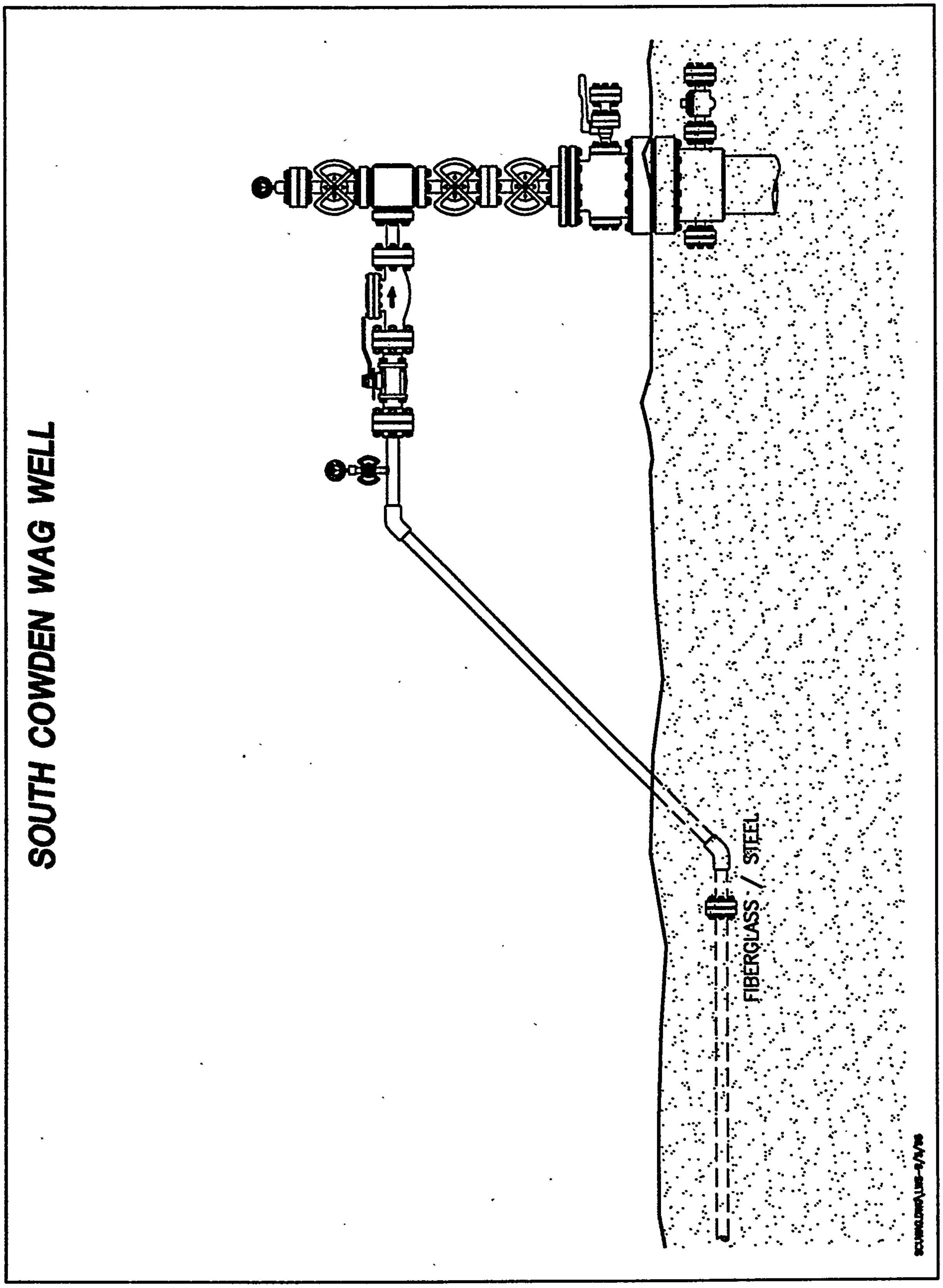
11


SOUTH COWDEN WAG WELL
FIBERGLASS / STEEL

APPENDIX V

FACILITIES COMPRESSION PREMISES

GAS RECOMPRESSION PREMISE

Based on the latest gas production forecast, full-scale dehydrated gas recompression will not be anticipated until early 1998. Due to the high H_2S content, the gas can not be flared on a continuous basis. Therefore, produced gas will continue to be sold to Amoco until late 1997. Once gas sales to Amoco are terminated, temporary compression can be utilized until full operations are required. Facility requirements and rental costs are based on the following premises:

1) Suction pressure 35 psi

2) Discharge pressure 1600 psi

3) Number of stages 4

4) Dehydration between 3rd and 4th stages.

5) Phillips Petroleum Company will supply fuel gas and electricity. Fuel gas line is currently in place and the electrical upgrade is noted in the cost estimate.

6) If compression is interrupted, all produced gas will go through the contractor's flare. The flare will require an assist fuel gas stream once the produced gas reaches a CO_2 content of 75%.

7) Liquids from compression site will be piped back into the free water knockout.

All compressor operations and maintenance will be conducted by a Phillips approved compressor operations contractor. The contract will be bid as a complete package for rental and the construction of the facilities. The construction of the facilities will be bid with a few modifications under testing and welding:

1) Piping will be nitrogen tested instead of hydrotested.

2) Field fabricated piping will be stressed relieved.

3) All welding will be in accordance to ASME B-31.3.

4) 100% of all welds above 2" will be radiographed 100%.

5) Pipe will be 0.45 CE or less and welded with 5P+ for the root pass and 7018 for the filler and cap.

Facility construction should be completed by the third quarter of 1996. Early construction will cut material and labor cost and allow for immediate installation of compression without extensive down time. Horsepower requirements are calculated according to the gas production forecast in the following table.

YEAR	GAS (MCF/D)	REQUIRED HP	HP SET
1995	90		
1996	93		
1997	184	46	150
1998	1055	264	500
1999	2125	531	500
2000	2752	688	750
2001	3158	790	750
2002	3788	947	1500
2003	4364	1091	1500
2004	4841	1210	1500
2005	4904	1226	1500
2006	4463	1116	1500
2007	4189	1047	1500
2008	4825	1206	1500
2009	5677	1419	1500
2010	6200	1550	1500
2011	5986	1497	1500
2012	5658	1415	1500
2013	5934	1484	1500
2014	6704	1676	1750
2015	7351	1838	1750
2016	5849	1462	1750
2017	5759	1440	1750
2018	6293	1573	1750
2019	6562	1641	1750
2020	7079	1770	1750
2021	6249	1562	1750
2022	4666	1167	1000
2023	4068	1017	1000
2024	4060	1015	1000
2025	3652	913	1000

SOUTH COWDEN UNIT
CO_2 REINJECTION COMPRESSOR FACILITY

Engineering and Drafting

The drawing package will consist of the following:

- Piping and Instrumentation Diagrams.
- Site Layout
- Site Excavation
- Site Drainage Plan
- ESD Schematic and Layout
- Foundation Layout
- Miscellaneous Civil, such as Individual Foundations, Piers and Supports
- Piping Plan and Elevations
- Utility Piping Routing
- Conduit Layout and Runs
- Termination Schematic

The station will be designed to ANSI B31.8.

Engineering Summary

While the "up-front" cost may be slightly higher initially, the cost per horsepower will drop substantially when expansion is complete.

Areas affected by this approach are as follows:

- Line Sizing

  All common headers are designed based upon a maximum flow rate of 8.6

MMCFD with 2,000 hp of compression.

- Tank Sizing

  Tank sizing will accommodate the 2 compressor scenario.

- Site Size

  The site will accommodate the 2 compressor scenario, maintaining a 100 foot minimum distance from compressors to dehydrator/flare.

- Inlet Separator

  Separator is sized for the full 8.6 MMCFD scenario.

- Vent Header

  Header sizing and blowdown valve is sized for total site capacity with 2 compressors.

- Electrical

  Power distribution center will handle additional power requirements associated with expansion. (Additional lights, etc.)

- Dehydration

  Dehydration is capable of handling 4.0 MMCFD. Before expansion is complete additional cost will be associated with resizing of contact tower.

- VRU

  Vapor Recovery unit will be adequate for expansion.

- Parts Building

  Will be used for storage of spare parts for total site equipment. It is also necessary for location of telephone call-out equipment and H_2S Monitoring Panel.

- H_2S Monitoring

  Initial system will consist of four (4) remote sensing heads reporting to central monitoring panel. Head will be installed at the compressor (2), tank battery (1), and dehydrator. System is expandable for future expansion with minimal cost. Visual and audible alarms will be given, station with E.S.D. and call-out will be activated.

General Information

- E.S.D. System

This system will consist of (1) fail closed suction block valve, (1) fail closed discharge block valve,, (1) fail open blowdown block valve, E.S.D. panel, and (7) trip hand stations. Upon E.S.D. all gas within the site perimeter will go to flare. System will be manual except that it will be tripped due to high H_2S levels detected by the H_2S monitoring system.

- Safety

Protective breathing equipment will be maintained at two locations on site. Wind socks (2) will be installed. H_2S monitoring will be utilized. All required safety signs will be posted. A Contingency Plan will be generated and supplied to the required parties. (As per Texas Railroad Commission Rule 36.) Fire extinguishers and protective barriers will be provided.

Field Construction Cost

Price includes:

Construction labor & Equipment (Mechanical and Electrical)
Safety Material
Site Material (Miscellaneous not in Material Summary)
Concrete
Fencing
X-ray
Hydrotesting
Transportation

Construction Scope of Work South Cowden Unit

A. **Civil**

1. Site 200' x 200'

This site will be degrubbed of all organic material. Any cut that is required to level site will be moved to the fill end of the pad site and compacted with a drum type roller in maximum lifts of 18". (Lifts will be determined by amount of fill required.) The site will be well drained and constructed with a crown running lengthwise down the center which will slope 1% to each side. The finished site will have a 6" thick cap of crushed caliche, rolled and compacted to smooth finish. Gravel will be spread around major equipment and vehicle traffic areas.

2. Concrete

All concrete will have a minimum compressive strength of 4,000 psi. All concrete surface will be free of any defects such as honeycombs or air pockets. All exposed corners will be chamfered 3/4" @ 45°. Finish will be "light broom" unless otherwise noted.

3. Backfilling

All excavations on the site that require backfilling will be brought up in 12" lifts, watered (if necessary) and compacted with portable hand operated "jumping jacks".

4. Fencing

Fencing will be constructed for livestock restriction only. A 5 strand barbed wire fence utilizing metal teepost, wooden post and 12 gauge 2 point wire will be installed. Access will be through two 14' aluminum gates and 3 man gates.

B. **Insulation, Painting and Safety**

1. Insulation

All condensate dump lines above grade will be insulated with block insulation, skinned with 0.016 aluminum, and banded with 1/4" stainless steel banding.

2. Painting

Surface preparation before painting will be to remove all loose dirt, scale and oil by means of pressure washing and/or wire brush only. Primer will be of a red oxide type. Finish will be gray enamel.

3. Safety

The finished site will be furnished with required warning signs, "No

Smoking", "Hearing & Eye Protection Required", "H_2S Present", etc. Protective vehicular barriers will be installed where necessary. Fire extinguishers will be available at each piece of major equipment.

C. **Testing**

1. Field installed process piping above 2" will be hydrotested. Hydrotesting will be performed at 1 ½ times the design pressure for the associated system that the line is in. Hydrotest will be for 2 hours only as per B31.8.

2. All utility lines 2" and below will be air tested @ 100 psig and checked by the soap and water method. The waste water lines and header will not be tested.

3. Field fabricated piping will not be stressed relieved. Rockwell hardness testing will be done on all welds associated with the field gas. A Rockwell hardness of 22 or below will be acceptable.

D. **Welding**

1. Welders will be certified by Welding Procedures.

2. All welding will be in accordance to A.P.I. 1104. Interpretation will also be to A.P.I. 1104.

3. 10% of all welds on piping above 2" will be radiographed 100%.

E. **Pipe Supports**

1. All pipe supports will be beam and pipe stantions with stantions concreted into the ground.

2. Heavy u-bolts will be utilized for all supports.

F. Piping/Fittings

1. All piping material will be SA-106-B grade seamless.

2. All below grade pipe will be butt-weld or socket-weld.

3. All socket-weld or screwed fittings will be 3000# rated minimum.

4. All butt-weld fittings will be SA-234-WPB grade.

G. **Grouting**

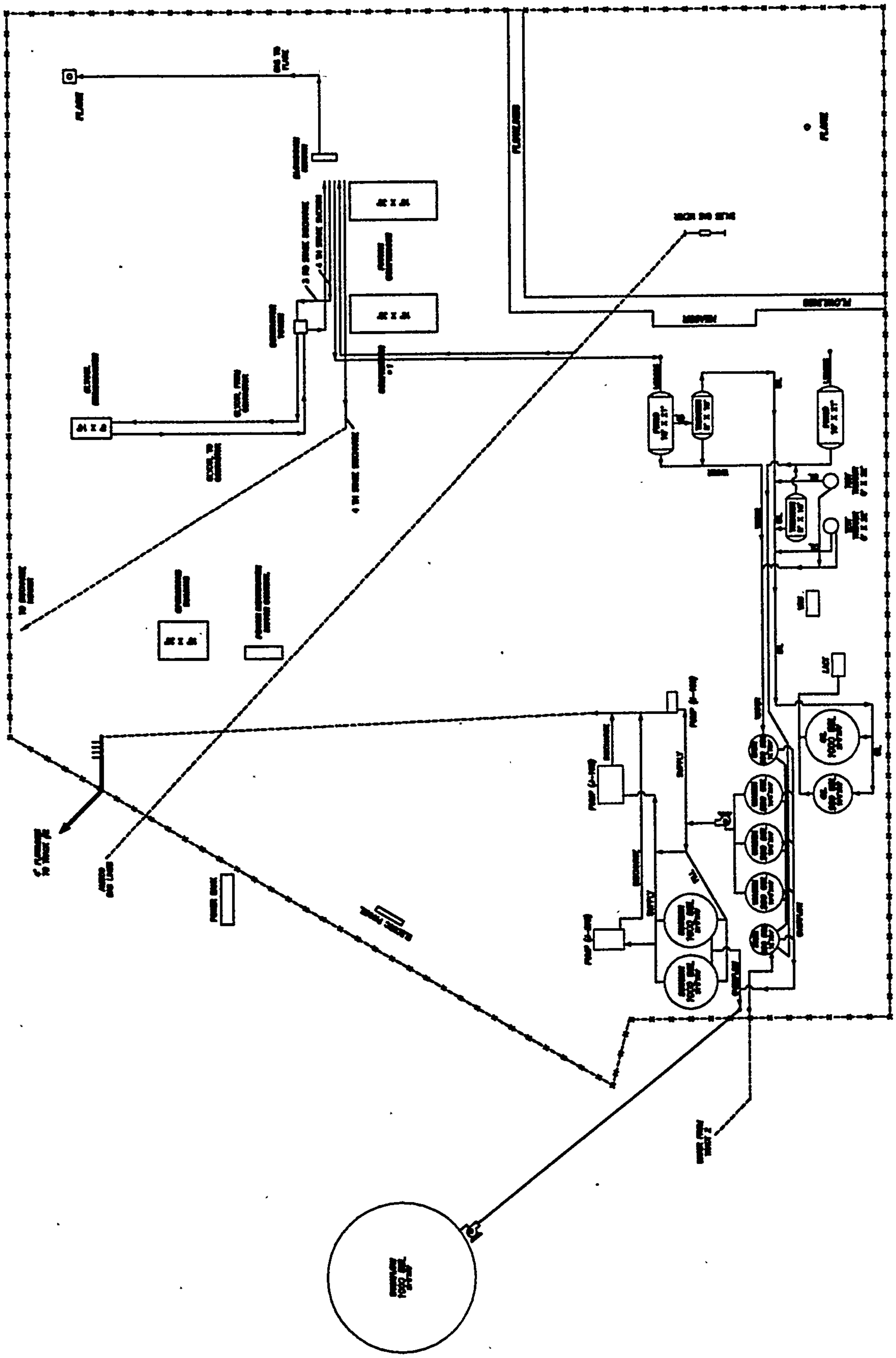
1. Grouting will be of the sand and cement type poured in accordance with grouting procedure and specifications.

H. **Electrical**

1. Electrical will be to N.E.C. specifications and good industry practice.

I. **Transportation**

1. Transportation of compressor and all associated material will be furnished.



APPENDIX VI

WATER DISPOSAL
PREMISES

WATER INJECTION AND/OR DISPOSAL

Premises:

It is premised: 1) **PRIORITY 1 and 2 will be completed during the first and second year** respectively; and
2) current injection pumps are adequate to handle the South Cowden Unit produced water during the CO_2 project.

Priority 3, the option with the highest associated risk and cost, will be completed only if necessary and is not accounted for in the project economics. The attached map details well conversions, etc. THESE PREMISES DO NOT INCLUDE DETAILS ON WAG INJECTORS.

Details:

PRIORITY 1: Convert wells to water injection and apply for increased wellhead injection pressure in (most) all current injectors.
==>It is estimated this work will result in a total Unit water injector capacity of 9000 BWIPD.

PRIORITY 2: Deepen two, off-structure injectors.

PRIORITY 3: Re-enter 2-18 and convert to water disposal.

PRIORITY 1

Step 1: Apply to TRRC to convert seven (7) wells to water injection**:

2-15 (redrill)
2-21
5-02 **MAXIMUM INJECTION PRESSURE = 1700 psi
5-08 AVERAGE INJECTION PRESSURE = 1500 psi
6-18
8-03
8-18

Step 2: Apply to TRRC for increased wellhead injection pressure. MAXIMUM 1700 psi and AVERAGE 1500 psi, on the following current water injection wells ($100/well):

1-04	4-03	6-16	8-15
2-13	5-01	8-04	
2-16	6-11	8-08	
2-19	6-12	8-09	

Step 3: The following water injectors should be plugged upon successful completion of the horizontal WAG injectors:

6-03
6-07
7-03
7-04

PRIORITY 2

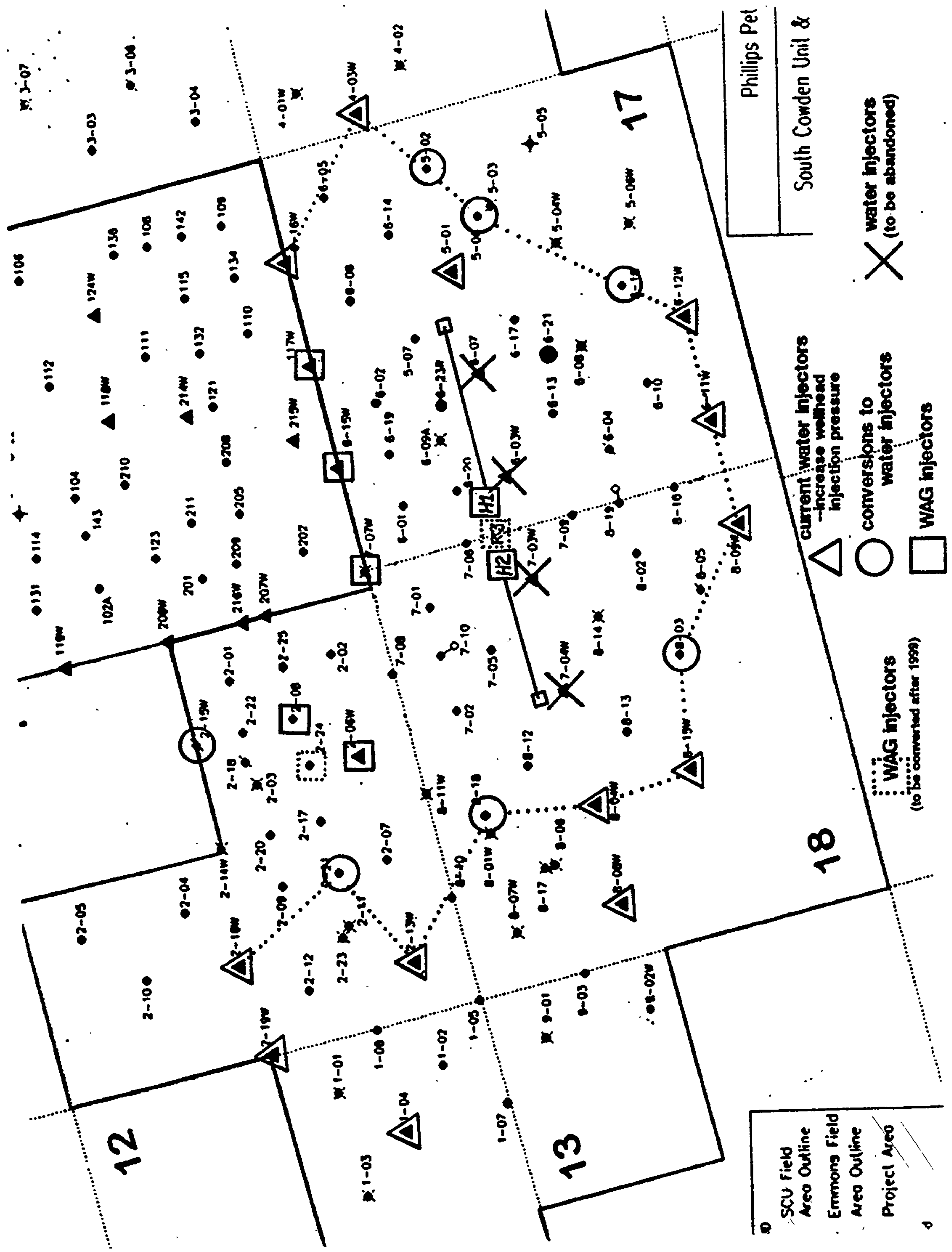
Additional injection capacity may be achieved through deepening two current water injectors each 500' into the San Andres (Zone A). The wells identified as candidates are off-structure water injectors and presently completed 4-1/2" openhole:

4-03
6-11
6-12
8-09

PRIORITY 3

Further injection/disposal capacity is available if the 2-18 producer is re-entered and completed for disposal purposes. This well, drilled in 1966 as a deep test to the Ellenburger, was subsequently recompleted through 9-5/8" casing as a San Andres producer. Well is currently TA'd with various open perfs and cement plugs inthe San Andres interval.

The most promising interval for disposal would be the Ellenburger at 14,100' -- this interval recovered 9550' VSGCSW during initial DST test and thus indicates good permeability. A potential shallower disposal zone is present at 6300'-6800' and merits testing. However, both require substantial capital and would also require successful squeezing of the San Andres perforations. If water production is such that this well is needed - it is recommended the old 5-1/2" casing stub is not re-entered but rather a plug set above and new hole drilled to +14,100'.



Phillips Pet
South Cowden Unit &
17
18
12
13
current water injectors
-increase wellhead
injection pressure
conversions to
water injectors
WAG injectors
water injectors
(to be abandoned)
WAG injectors
(to be converted after 1999)
SCU Field
Area Outline
Emmons Field
Area Outline
Project Area

APPENDIX VII

FACILITIES AUTOMATION PREMISES

SOUTH COWDEN UNIT CO2 FLOOD
AUTOMATION PREMISE

I. Injection Wells

1) Operating Parameters
   a) CO_2 Volume - 750 MCFD to 1.5 MMCFD for Vertical injection wells 300 to 600 BPD - 1" Turbine Meter (170 - 1.7K)
   b) CO_2 Volume - 3-5 MMCFPD for Horizontal injection wells 1200-2000 BPD - 1.5" Turbine meter (515-6K)
   c) CO_2 Pressure - 1500 PSI MAX.
   d) H_2O Volume - 600-1300 BPD for Vertical injection wells - 1" Turbine meter
   e) H_2O Volume - 1800-3900 BPD for Horizontal injection wells - 1.5" Turbine meter
   f) H_2O Pressure - 1700 PSI Max., 1500 PSI Avg.

2) Equipment required per well assembly:
   a) Strainer
   b) Turbine Meter
      i) Vertical injection wells - 1"
      ii) Horizontal injection wells - 1.5"
   c) Check valve
   d) Relief valve-set 1750 PSI (sized for thermal expansion only)
   e) Choke with AC Actuator
   f) Injection Line Pressure Transmitter
   g) Block Valve

3) Functional Requirements
   a) Measure
      i) Injection Line Pressure
      ii) CO_2 Volumes in BPD
      iii) H_2O Volumes in BPD
      iv) Differential Pressure
   b) Control
      i) CO_2 Injection Rate
      ii) H_2O Injection Rate
      iii) Maximum Injection Pressure
      iv) Choke setting
         a) Control on set point
         b) Close on:

1) High Flow rate
2) Low Injection line Pressure
3) Manual ESD at the CO_2 Manifold

c) ESD valves must be manually reset at the Bristol individually.

c) Alarms
   i) High/Low Injection line Pressure
   ii) Power Failure
   iii) High/Low Differential Pressure
   iv) High/Low Flow Rate
   v) ESD

d) Trend
   i) Injection line Pressure
   ii) Injection Temperature
   iii) Yesterdays H_2O/CO_2 Volumes
   iv) Differential Pressure

e) Morning Reports
   i) Todays Volume
      a) CO_2
      b) H_2O
   ii) Yesterdays Volume
      a) CO_2
      b) H_2O
   iii) This Months Volume
      a) CO_2
      b) H_2O
   iv) Last Months Volume
      a) CO_2
      b) H_2O
   v) Total Volume
      a) CO_2
      b) H_2O

II. Injection Manifold

1) CO_2 Injection Manifold Assembly
   a) CO_2 Supply Block Valve
   b) CO_2 ESD Valve (Fail Close)
   c) CO_2 Supply Relief Valve with test insert and block valve (set 1750 PSI)
   d) CO_2 Re-injection Compressor ESD Valve (Fail Close)
   e) Relief Valve with test insert and block valve (set 1750 PSI)
   f) Pressure Transmitter

g) Temperature Transmitter
h) Compressed CO_2 Block Valve
i) Compressed CO_2 Relief Valve with test insert and block valve (set 1750 PSI)

2) H_2O Header
   a) Block Valve
   b) ESD Valve not required
   c) Block Valve for each injection run

3) Information
   a) Purchased CO_2 volumes will be gathered from supplier manually
   b) Compressed gas volumes will be gathered from contractor manually.

4) Control
   a) Bristol DPC 3330 with Radio and antenna
      Note: Radio required for CO_2 monitor alarms
   b) It is premised to use clean CO_2 to operate the ESD valves with a nitrogen backup in lieu of installing an air compressor.
      i) If an air compressor is used a pressure switch is needed to alarm on low air pressure.

III. Monitoring Requirements

1) Ambient Monitoring
   a) CO_2 ambient monitors are not required at Tract 2 or 6 batteries.
   b) CO_2 monitoring will be required at the Injection Manifold site and at each of the Horizontal injection wells. The monitors at the manifold will be located at the north and south fence lines. The monitors will be located on the south side of the injection well pads.
   c) H_2S ambient monitors to be located at the following locations:
      i) 6-05
      ii) 6-21
      iii) 8-19
      iv) Between 5-02 and 6-17
      v) Each of the four corners of the Tract 6 battery.
   d) Ambient monitors will be AC powered.
   e) Each monitor to be equipped with an AE 604 RTU, radio and antenna for each remote location, not at Tract 6 battery. The original alarms will be utilized.
   f) Each monitor is to be equipped with a green or blue warning

beacon.

2) Produced Gas CO_2 Monitoring
   a) Required 1 on suction of compressor unit and 2 on test separators at Tract 6 battery (total of 3).
      i) A 3 pen strip chart with red, green and black pens to record CO_2 levels in streams.
   b) Required on 2 test separator at Tract 2 (total of 2).
   c) Local monitoring only, no SCADA.

   d) Local blue or green light/beacon.

IV. **Producing Wells**

1) Beam Pump
   a) Pump Off Control
   b) Stuffing Box Leak Detector
   c) Radio and Antenna

2) Submersible Pump
   a) RTU, radio and antenna is not required.

V. **Tank Battery**

1) Requirements
   a) Tract 6 will be focal point of project.
   b) Tract 2 will be converted to a satellite.
   c) Existing alarms will be utilized, RTUs will not be added to the SCADA at this time. RTUs will be added as part of the Goldsmith SCADA/Alarm upgrade.

VI. **SCADA**

1) Penwell Tower
2) Share frequency with NPU
3) Host to be located at Odessa Office
4) A laptop PC will be utilized for remote Dial-in from the SCU office.
5) RTUs
   a) 36 POCs
   b) 1 Bristol at Header
   c) 6 AE RTUs for CO_2 and H_2S monitors

VII. Labor Requirements

1) Automation Technician 37% of one technician.

APPENDIX VIII

ELECTRICAL PREMISES

SOUTH COWDEN UNIT CO2 FLOOD
ELECTRICAL PREMISE

I. **Power Source**

TU Electric supplies the system at 12,470 Volts, three phase, ungrounded. The contract is interruptible for 1232 KW. The current demand is 606 KW, the billing demand is 986 KW. The penalty is $1,257.80 per month. The contract cannot be re-negotiated unless it is cancelled. There are no major modifications planned for the distribution system other than extensions required for new producers and the CO_2 header.

II. **Injection Wells**

Injection wells will not have a requirement for electricity as they will be controlled from the central header. The exception will be that the horizontal injectors will require 120 VAC for the CO_2 monitors.

III. **Injection Manifold**

The injection manifold will require AC power for the chokes, ESD valves, Bristol control, CO_2 metering, monitoring, etc. Estimated load 10 KVA. The site will be UNCLASSIFIED as there will not be enough hydrocarbon in the injection stream to be explosive. The CO_2 will be purchased from Enron.

An air compressor may be required, if CO_2 CO2 with nitrogen backup cannot be utilized for operating the ESD valves.

IV. **Producing Wells**

Each producer will be supplied with primary service with a transformer bank for each location due to the projected horsepower requirement.

1) Beam pumped wells
Each beam will be a minimum of 50 HP, 480 volts, 3 phase, 60 Hz.

2) Submersible pumped wells
Seaboard type well heads have been discussed. It was decided to install them if and when they are required. The cost for conversion has not been included in this premise.

3) New drills-produce

a) It is premised that each will require:
300' of #4 ACSR, a transformer bank with 3-25 KVA transformers and two anchors. New transformers will be purchased for the new drilled producers. The re-drilled producers will use transformers which will be relocated from wells which are converted to injection, or plugged during the coarse of the project. All poles and hardware will be new.

b) The new drills are:
   i) RC-3 and 7-98 in 1996
   ii) 7-99 in 1997
   iii) 6-99 in 1998
   iv) 4 wells in 1999

c) Replacement wells:
   i) 8-14A in 1996
   ii) 6-04A in 1997
   iii) 2-03A in 1998

d) Reactivate wells:
   i) 7-05 and 6-20 in 1996
   ii) 6-19, 7-02, 7-08, and 8-13 in 1997
   iii) 2-20 and 6-05 in 1998

e) Convert to WAG injection wells:
   i) RC-3 and 2-24C

V. Tank Batteries

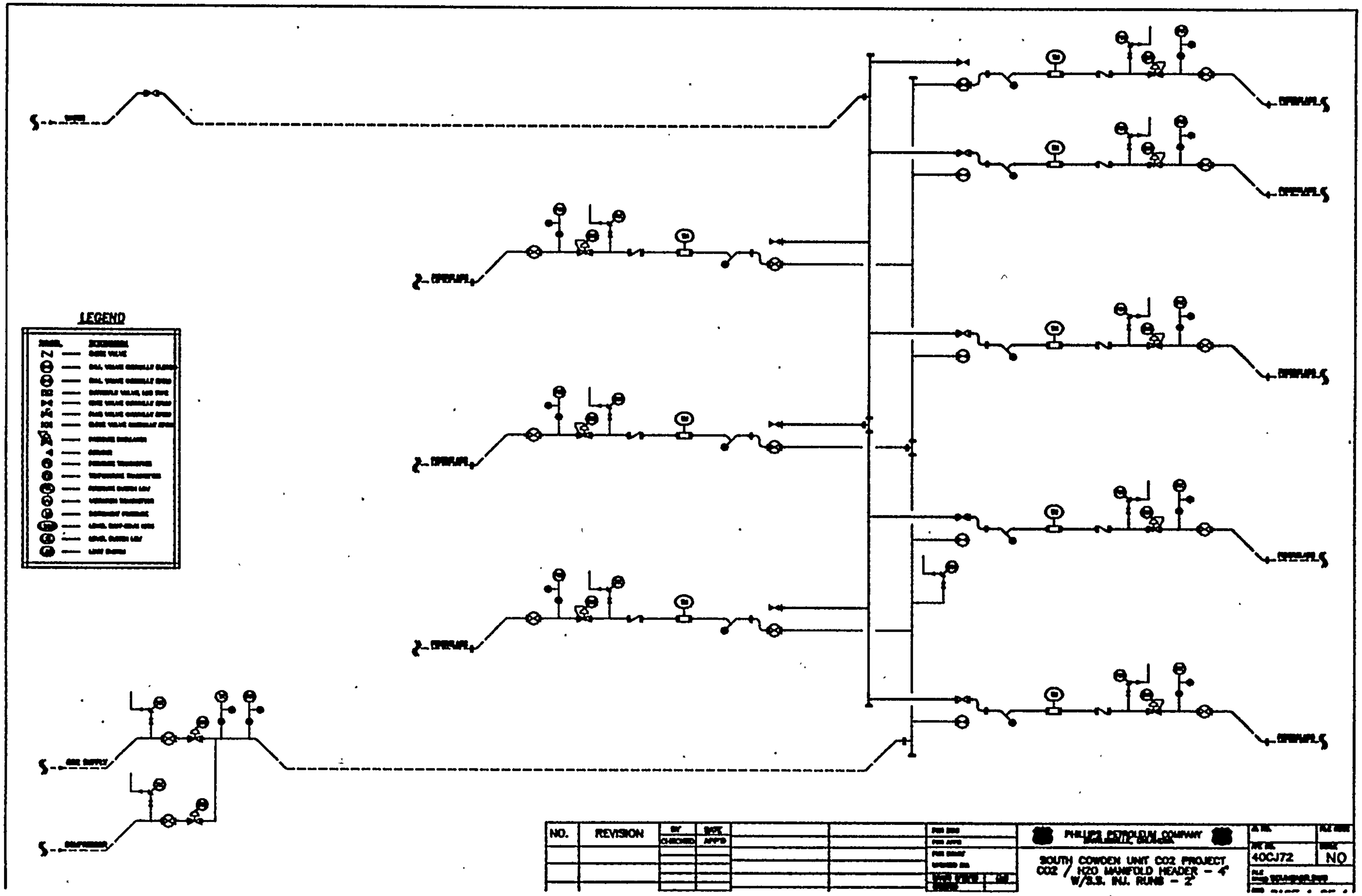
1) Tract 6 battery will require that the LACT and VRU be upgraded to be in compliance.
2) Tract 2 battery will be converted to a satellite and will require electricity for the produced CO_2 monitor and possibly an air compressor for the test separator dump valves.

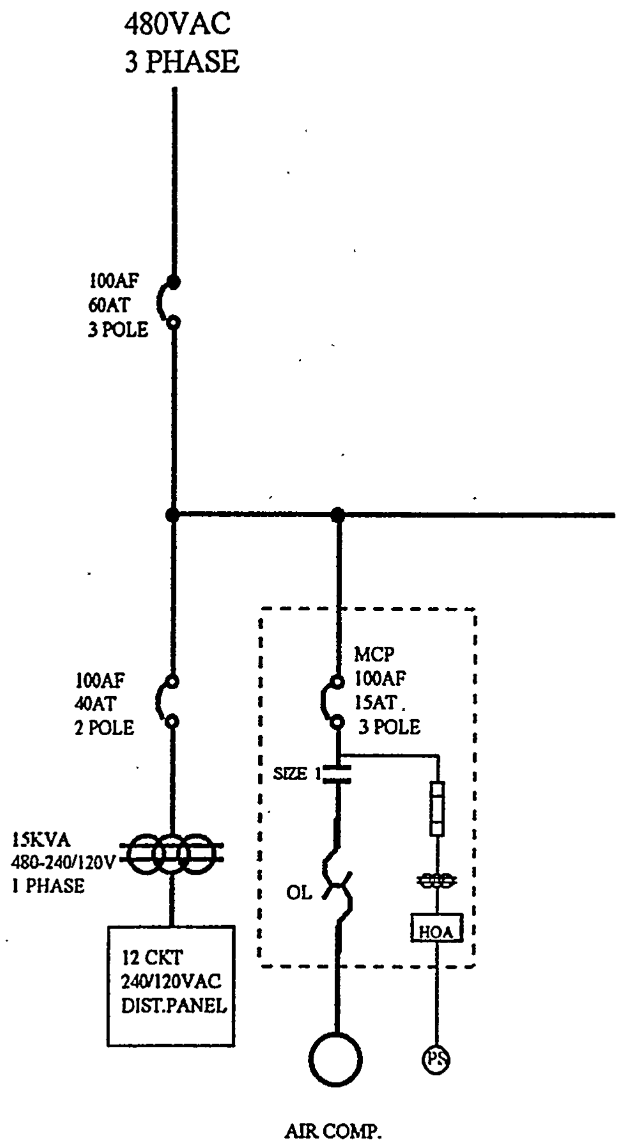
VI. Re-injection Facility

Phillips will furnish power to the contractor as required. A new 75 KVA bank will be set in the vacinity of the existing 300 KVA water injection bank. The bank may be utilized for temporary gas reinjection before the main injection station is installed due to early CO_2 breakthrough.

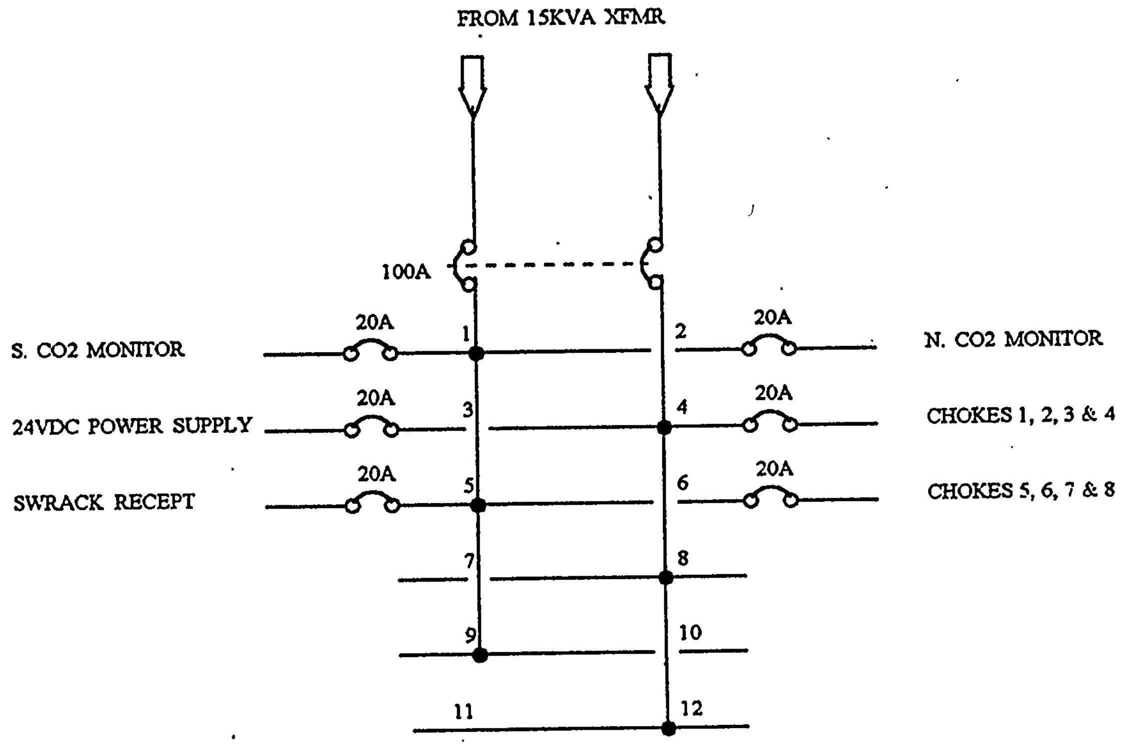
VII. New Work

All new work is to conform to the PHILLIPS ENGINEERING DIRECTIVES.


LEGEND
NO.
REVISION
PHILLIPS PETROLEUM COMPANY
SOUTH COWDEN UNIT CO2 PROJECT
CO2 / H2O MANIFOLD HEADER - 4"
W/S.S. INJ. RUNS - 2"
40CJ72
NO



SOUTH COWDEN UNIT CO2 INJ.
3 PHASE ONELINE



SOUTH COWDEN UNIT CO2 INJECTION
SINGLE PHASE 220/120 VAC PANEL

APPENDIX IX

RISK ASSESSMENT

PRELIMINARY RISK ASSESSMENT

Given below is a preliminary risk assessment for the South Cowden CO_2 Injection Project. This assessment provides an initial review of safety, property loss and environmental risks associated with the project. Additional reviews will be conducted as considered prudent.

The most significant potential hazard, H_2S exposure to the public, has been reviewed in detail. Dispersion modeling results indicate that the worst case release would not result in exposure of the public to hazardous concentrations of H_2S. Reasonable precautions are planned to protect the public from accidental H_2S release.

A review of the risks and precautions is given below:

Risks

A. <u>Safety</u>

The primary safety risk relates to release of hydrogen sulfide. There are four main scenarios in which a release of H_2S may occur. These are:

1. Blowout of Injection Well
2. Rupture of Reinjection System
3. Blowout of Producing Well
4. Rupture of Field Production Header
5. Rupture of Production Flowline

Of these, only blowout of a CO_2 injection well is considered as serious. It is estimated that either of the two "horizontal" injectors will be able to take approximately 5 MMCFD maximum injection rate. Although the open flow potential of the wells is unknown, a conservative estimate of 7.5 MMCFD was used for calculation of worst case 100 ppm radius of exposure for an uncontrolled blowout. Mark Deese of HES, Bartlesville ran the TRACE dispersion modeling program and calculated a 100 ppm ROE of 928 feet. Since the surface location of the injection wells is more than 2000 feet from the nearest residence; public exposure to hydrogen sulfide should not be a problem. Additional modeling was done for rupture of the CO_2 and production headers. These cases were found to be of significantly less concern than blowout of an injector well.

Producing wells closest to the residential area were reviewed and it was determined that present gas production rates are so low that the rupture of flowlines would present little potential for 100 ppm H_2S exposure to the public. The scenario of a producing well blowout is considered as unlikely because of the low oil and gas production rates and very high water production rates for the wells located in proximity to the residential area. Also, none of the producing wells are flowing wells and all are produced through use of pumping units. Further, existing producers in and near the residential area are planned to be converted into a "ring" of water injection wells. This conversion is intended to eliminate concerns for H_2S exposure due to wellhead/flowline leaks near the residential area.

B. Property Damage

The primary cause of property damage would be a tank battery fire. The consequences of a tank battery fire would generally be cost of replacement of tanks and/or process equipment and loss of production while reconstructing facilities. In the event of a battery fire, surplus tanks and vessels are available at low cost. Also, temporary tanks and production equipment could be utilized to minimize down time associated with a fire loss.

Fire risk to the public is minimal considering the distance from the tank batteries to public property. The risk to operating personnel is minimal, since NAP hot work and hot tapping procedures preclude operations which would present fire hazards. Also, incipient fire training is periodically provided to operations personnel.

Following a tank battery fire, some environmental remediation would probably be required. However, this would likely involve the standard practice of aerating and fertilizing the contaminated soil until oil content is within Railroad Commission limits.

C. Environmental

Oil spill represents the greatest risk of environmental damage. However, the South Cowden Field is not located in an environmentally sensitive area. There are no waterways, wetlands, endangered species habitats or other sensitive areas which would be affected by an oil spill. The field is not considered to fall under SPCC requirements. Spills would be remediated according to Railroad Commission requirements.

Precautions

A. Hydrogen Sulfide

Fixed H_2S monitors will be installed at the tank battery, the production headers and along the property line between the field and the residential area. These monitors will alarm upon detection of H_2S and will automatically "call out" to notify appropriate personnel of H_2S detection. Additionally, fixed CO_2 monitors will be installed at the injector wells and at the CO_2 header and will also be connected to an alarm/call out system.

A written Hydrogen Sulfide Contengency Plan will be prepared for the project.

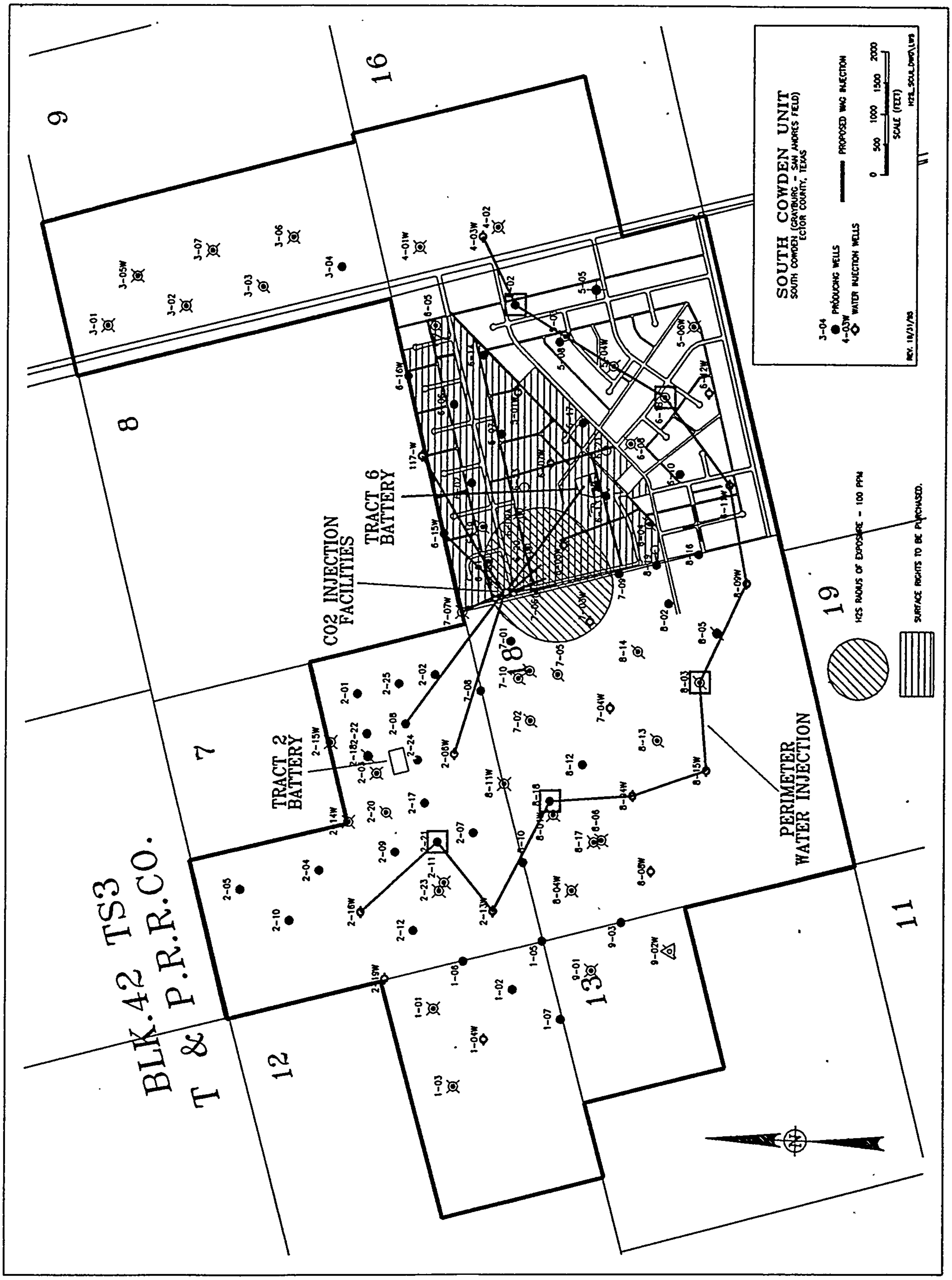
B. Reinjection System Safety Devices

The CO_2 reinjection system is being equipped with appropriate safety sensors and shut down devices which will isolate the system in the event of an undesirable event such as a leak.

DuPont's TRACE model was used to determine chemical concentrations and cloud dynamics for this spill. The model basically shows a theoretical release of carbon dioxide. Several release scenarios were modeled to determine the maximum distance where 4900 ppm occurs, which is approximately 100 ppm of H_2S. Various emission rates were used based on the data you supplied. Each emission rate was modeled with different wind speeds of 5 mpd, 10 mph, and 15 mph. Also, each emission rate was modeled with different temperatures of 30° F, 70°F, and 110°F.

Year	Mass Available	**5 MPH**			**10 MPH**			**15 MPH**		
	(lbs/sec)	30°F	70°F	110°F	30°F	70°F	110°F	30°F	70°F	110°F
1995	.0018	66'	132'	132'	264'	264'	264'	396'	396'	396'
1998	1.057	281'	269'	268'	304'	256'	253'	264'	344'	320'
2001	2.292	418'	393'	380'	349'	358'	347'	398'	389'	343'
2005	3.224	501'	471'	559'	387'	397'	393'	357'	391'	374'
2010	4.278	578'	544'	528'	447'	449'	455'	457'	466'	398'
2015	5.274	656'	656'	585'	513'	498'	489'	493'	502'	430'
MAX	9.86	890'	928'	798'	704'	657'	628'	636'	630'	556'

The worst case shows that the furthest distance where 4900 ppm of CO_2 occurs is 928 feet downwind from the source. From this modeling, if light winds are present during an accidental release, reasonable precautions should be taken to protect the community surrounding this facility. Modeling results are "best guess" and usually conservative.



SOUTH COWDEN UNIT
SOUTH COWDEN (GRAYBURG - SAN ANDRES FIELD)
ECTOR COUNTY, TEXAS
PRODUCING WELLS
WATER INJECTION WELLS
PROPOSED WAG INJECTION
SCALE (FEET)
0 500 1000 1500 2000
H2S RADIUS OF EXPOSURE - 100 PPM
SURFACE RIGHTS TO BE PURCHASED.
BLK.42 TS3
T & P.R.R.CO.
TRACT 2 BATTERY
TRACT 6 BATTERY
CO2 INJECTION FACILITIES
PERIMETER WATER INJECTION
9
16
8
7
12
13
18
19
11

APPENDIX X

FACILITIES LAND PURCHASE
PREMISES

WITH 1 ATTACHMENT

SOUTH COWDEN CO_2 PROJECT

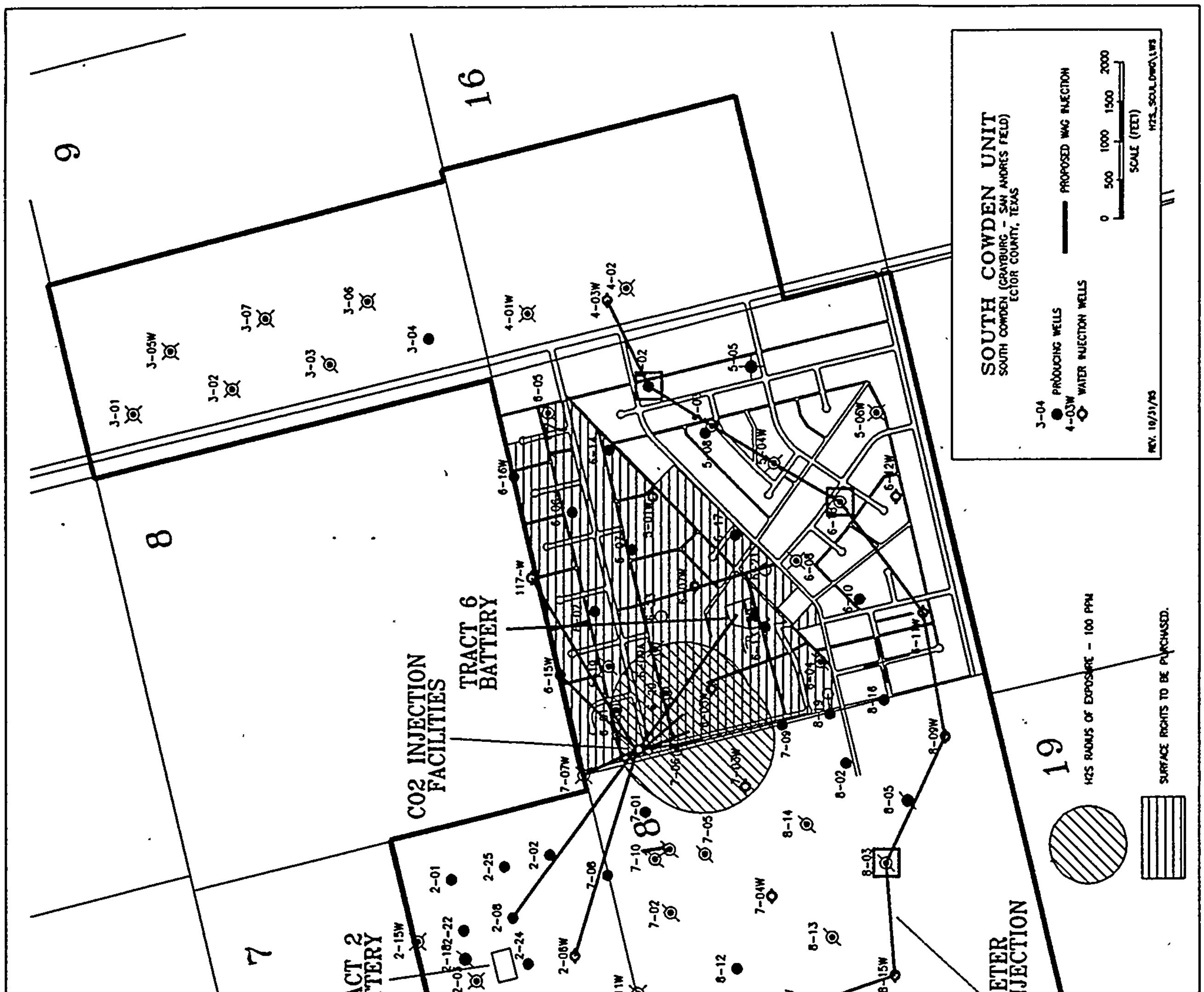
Land Purchase Premise

The acreage under Section 17 Block 42, which is the location of the Tract 6 Battery and the future location of the injection facilities will be purchased. The acreage will extend from the north boundary of the section to the 385 Highway, then to the diagonal line of the 385 Ranch West Estates, then to the west line of the section, then back to the north line. Some additional lots south of the diagonal line will be purchased as well.

The intent of this purchase is as follows:

1. Reduce the cost of payment of damages.
2. Reduce the safety hazards from CO_2 or H_2S.
3. Allow uninhibited development of the main CO_2 flooded area.

See attached plot.



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SURFACE RIGHTS TO BE PURCHASED.

APPENDIX XI

FACILITIES CATHODIC PROTECTION PREMISES

SCU CATHODIC PROTECTION PREMISES

Install 21 deephole ground beds, that will service 61 well casings, via overhead lines and buried lines.

Each well will require 6 to 10 amps of DC current to adequately protect casings, exact requirements can be established after casing profile potential logs are performed.

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