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CO2 Huff-n-Puff Process in a Light Oil
Shallow Shelf Carbonate Reservoir

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By
Scott C. Wehner, R.J. (Bob) Boomer,
Roger Cole, John Preiditus and Joe Vogt

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Assistant Secretary for Fossil Energy

Jerry Casteel, Project Manager
Bartlesville Project Office
P.O. Box 1398
Bartlesville, OK 74005

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Prepared by
Texaco Exploration and Production, Inc.
Midland, Texas

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ABSTRACT

The application of cyclic CO₂, often referred to as the CO₂ Huff-n-Puff process, may find its niche in the maturing waterfloods of the Permian Basin. Coupling the CO₂ H-n-P process to miscible flooding applications could provide the needed revenue to sufficiently mitigate near-term negative cash flow concerns in the capital intensive miscible projects. Texaco Exploration & Production Inc. and the U. S. Department of Energy have teamed up in an attempt to develop the CO₂ Huff-n-Puff process in the Grayburg/San Andres formation; a light oil, shallow shelf carbonate reservoir within the Permian Basin. This cost-shared effort is intended to demonstrate the viability of this underutilized technology in a specific class of domestic reservoir.

A significant amount of oil reserves are located in carbonate reservoirs. Specifically, the *carbonates* deposited in *shallow shelf* (SSC) environments make up the largest percentage of known reservoirs within the Permian Basin of North America. Many of these known resources have been under waterflooding operations for decades and are at risk of abandonment if crude oil recoveries cannot be economically enhanced^{1,2}. The selected site for this demonstration project is the Central Vacuum Unit waterflood in Lea County, New Mexico.

Miscible CO₂ flooding is the process of choice for enhancing recovery of light oils³ and already accounts for nearly 12% of the Permian Basin's daily production.⁴ There are significant probable reserves associated with future miscible CO₂ projects. However, many are marginally economic at current market conditions due to large up-front capital commitments for a peak response which may be several years in the future. The resulting negative cash-flow is sometimes too much for an operator to absorb. The CO₂ H-n-P process is being investigated as a near-term option to mitigate the negative cash-flow situation--allowing acceleration of inventoried miscible CO₂ projects when coupled together.

The CO₂ Huff-n-Puff process is a proven enhanced oil recovery technology in Louisiana-Texas Gulf-coast sandstone reservoirs^{5,6}. Application seems to mostly confine itself to low pressure sandstone reservoirs⁷. The process has even been shown to be moderately effective in conjunction with steam on heavy California crude oils^{8,9}. A review of earlier literature^{5,10,11} provides an excellent discussion on the theory, mechanics of the process, and several case histories. Although the technology is proven in light oil sandstones, it continues to be a very underutilized enhanced recovery option for carbonates. However, the theories associated with the CO₂ H-n-P process are not lithology dependent.

It is anticipated that this project will show that the application of the CO₂ Huff-n-Puff process in shallow shelf carbonates can be economically implemented to recover appreciable volumes of light oil. The goals of the project are the development of guidelines for cost-effective selection of candidate reservoirs and wells, along with estimating recovery potential.

This project has two defined budget periods. The first budget period primarily involves tasks associated with reservoir analysis and characterization, characterizing existing producibility problems, and reservoir simulation of the proposed technology. The final budget period covers the actual field demonstration of the proposed technology. Technology transfer spans the entire course of the project.

This report covers the concluding tasks performed under the first budget period and the initial results of the second budget period.

Work is complete on the reservoir characterization components of the project. The near-term emphasis was to, 1) provide an accurate distribution of original oil-in-place on a waterflood pattern entity level, 2) evaluate past recovery efficiencies, 3) perform parametric simulations, and 4) forecast performance for a site-specific field demonstration of the proposed technology. Macro zonation now exists throughout the study area and cross-sections are available. The Oil-Water Contact has been defined. Laboratory capillary pressure data was used to define the initial water saturations within the pay horizon. The reservoir's porosity distribution has been enhanced with the assistance of geostatistical software. Three-Dimensional kriging created the spacial distributions of porosity at inter-well locations. Artificial intelligence software was utilized to relate core permeability to core porosity, which in turn was applied to the 3-D geostatistical porosity gridding. An Equation-of-State was developed and refined for compositional simulation exercises. These tasks were highlighted in the 1994 Annual Report.

The 1995 Annual Report will provide some conclusions to some of the work reported previously. However, this report deals predominantly with, 1) parametric simulation exercises, 2) site-specific simulation; history matching the waterflood and forecasted recovery, and 3) initial results from the field demonstration of the process.

A successful demonstration of the CO₂ Huff-n-Puff process could have wide application. The proposed technology promises several advantages. It is hoped that the CO₂ Huff-n-Puff process might bridge near-term needs of maintaining the large domestic resource base of the Permian Basin until the mid-term economic conditions support the implementation of more efficient, and prolific, full-scale miscible CO₂ projects.

EXECUTIVE SUMMARY

Texaco Exploration and Production Inc. (TEPI) was awarded a contract from the Department of Energy (DOE) during the first quarter of 1994. This contract is in the form of a cost-sharing Cooperative Agreement (Project). The goal of this joint Project is to demonstrate the Carbon Dioxide (CO₂) Huff-n-Puff (H-n-P) process in a light oil, shallow shelf carbonate (SSC) reservoir (Grayburg and San Andres formation) within the Permian Basin. The selected site is the TEPI operated Central Vacuum Unit (CVU) waterflood in Lea County, New Mexico. The CVU produces from the Grayburg and San Andres formations.

TEPI's mid-term plans are to implement a full-scale miscible CO₂ project in the CVU. However, the current market precludes acceleration of such a capital intensive projects in many similar reservoirs. This is a common finding throughout the Permian Basin SSC reservoirs. In theory, it is believed that the "immiscible" CO₂ H-n-P process might bridge the longer-term "miscible" projects with near-term results. A successful implementation would result in near-term production, or revenue, to help offset cash outlays of the capital intensive miscible CO₂ project. The DOE partnership provides some relief to the associated R & D risks, allowing TEPI to evaluate a proven Gulf-coast sandstone technology in a waterflooded carbonate environment. A successful demonstration of the proposed technology would likely be replicated within industry many fold--resulting in additional domestic reserves.

The principal objective of the CVU CO₂ H-n-P project is to determine the feasibility and practicality of the technology in a waterflooded SSC environment. The results of parametric simulation of the CO₂ H-n-P process, coupled with reservoir characterization, assisted in determining if this process was technically and economically ready for field implementation. The ultimate goal is to develop guidelines based on commonly available data that operators within the oil industry can use to investigate the applicability of the process within other fields. The technology transfer objective of the project is to disseminate the knowledge gained through an innovative plan in support of the DOE's objective of increasing domestic oil production and deferring the abandonment of SSC reservoirs. Tasks associated with this objective are carried out in what is considered a timely effort.

The application of CO₂ technologies in Permian Basin carbonates may do for the decade of the 1990's and beyond, what waterflooding did for this region beginning in the 1950's. With an infrastructure for CO₂ deliveries already in place, a successful demonstration of the CO₂ H-n-P process could have wide application. The proposed technology promises a number of economical advantages. Profitability of marginal properties could be maintained until such time as pricing justifies a full-scale CO₂ miscible project. It could maximize recoveries from smaller isolated leases which could never economically support a miscible CO₂ project. The process, when applied during the installation of a full-scale CO₂ miscible project could mitigate up-front negative cash-flows, possibly to the point of allowing a project to be self-funding and increase horizontal sweep efficiency at the same time. Since most full-scale CO₂ miscible projects are focused on the "sweet spots" of a property, the CO₂ H-n-P process could concurrently maximize recoveries from non-targeted acreage. An added incentive for the early application of the CO₂ H-n-P process is that it could provide an early measure of CO₂ injectivity of future full-scale CO₂ miscible projects and improve real-time recovery estimates--reducing economic

risk. It is hoped that the CO₂ H-n-P process might bridge near-term needs of maintaining the large domestic resource base of the Permian Basin until the mid-term economic conditions support the implementation of more efficient, and prolific, full-scale miscible CO₂ projects.

This project has two defined budget periods. The first budget period primarily involves tasks associated with reservoir analysis and characterization, characterizing existing producibility problems, and reservoir simulation of the proposed technology. The final budget period covers the actual field demonstration of the proposed technology. Technology transfer spans the entire course of the project. This report covers the concluding tasks performed under the first budget period and the initial results of the second budget period.

Work is complete on the reservoir characterization components of the project. The near-term emphasis was to, 1) provide an accurate distribution of original oil-in-place on a waterflood pattern entity level, 2) evaluate past recovery efficiencies, 3) perform parametric simulations, and 4) forecast performance for a site-specific field demonstration of the proposed technology. Macro zonation now exists throughout the study area and cross-sections are available. The Oil-Water Contact has been defined. Laboratory capillary pressure data was used to define the initial water saturations within the pay horizon. The reservoir's porosity distribution has been enhanced with the assistance of geostatistical software. Three-Dimensional kriging created the spacial distributions of porosity at inter-well locations. Artificial intelligence software was utilized to relate core permeability to core porosity, which in turn was applied to the 3-D geostatistical porosity gridding. An Equation-of-State was developed and refined for compositional simulation exercises. These tasks were highlighted in the 1994 Annual Report.

The 1995 Annual Report provides conclusions to some of the work reported previously. However, this report deals predominantly with, 1) parametric simulation exercises, 2) site-specific simulation; history matching the waterflood and forecasted recovery, and 3) initial results from the field demonstration of the process. Simulation results suggest that reservoir characterization of flow units is not as critical for a CO₂ H-n-P process as for a miscible flood. Entrapment of CO₂ by gas hysteresis is considered the dominant recovery factor for a given volume of CO₂. The repetitive application of the process was found to be unwarranted in a waterflooded environment. Future history matching of the performance will allow better forecasts and evaluation of the economic impact available with this underutilized process.

INTRODUCTION

CVU Development History.

The Vacuum Field was discovered in May, 1929 by the Socony-Vacuum Oil Company—a predecessor of Mobil. The discovery well was the New Mexico "Bridges" State Well No. 1 (drilled on the section line of Sec's 13 & 14, T16S R34E). The well was shut-in until 1937 when pipeline facilities became available to the area. The field is located 22 miles west of Hobbs in Lea County, New Mexico (Fig. 1). Field development began on 40-acre well spacing. By 1947 the field limits were defined. The CVU was infill drilled on 20-acre spacing during 1978-1979. Further reservoir development began in the late 1980's with sporadic infill drilling on 10-acre spacing—which continues. Enhanced recovery operations by waterflooding are in progress across the entire Vacuum field. Water injection at CVU was initiated in 1978.. A polymer augmented waterflood was initiated and completed during the mid-1980's. The CVU has performed well under waterflooding with ultimate recoveries (primary + secondary) forecast at 44.8% of original oil-in-place (OOIP). A plot of the CVU production and injection history is found in Fig. 2. The flood is quite mature in some areas, yet would be considered an adolescent in others due to varying reservoir qualities. Miscible CO₂ Flooding was initiated in 1985 by Phillips in the southeastern portion of the field, immediately east of the CVU. Fig. 3 identifies the Unitized operations of the Vacuum field. In addition to the San Andres/Grayburg producing horizons, there are 12 other formations that are, or have been productive in the Vacuum field. These, mostly deeper horizons were developed predominantly during the 1960's.

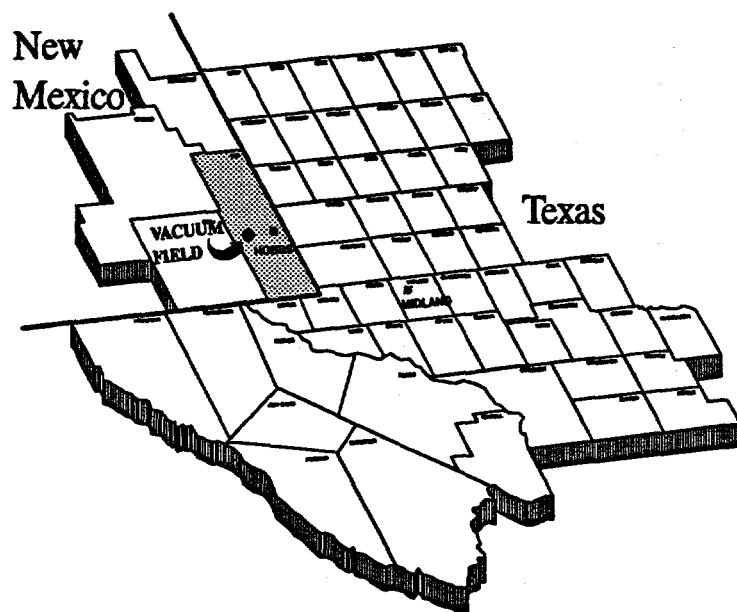


Fig. 1: Regional location of Central Vacuum Unit.

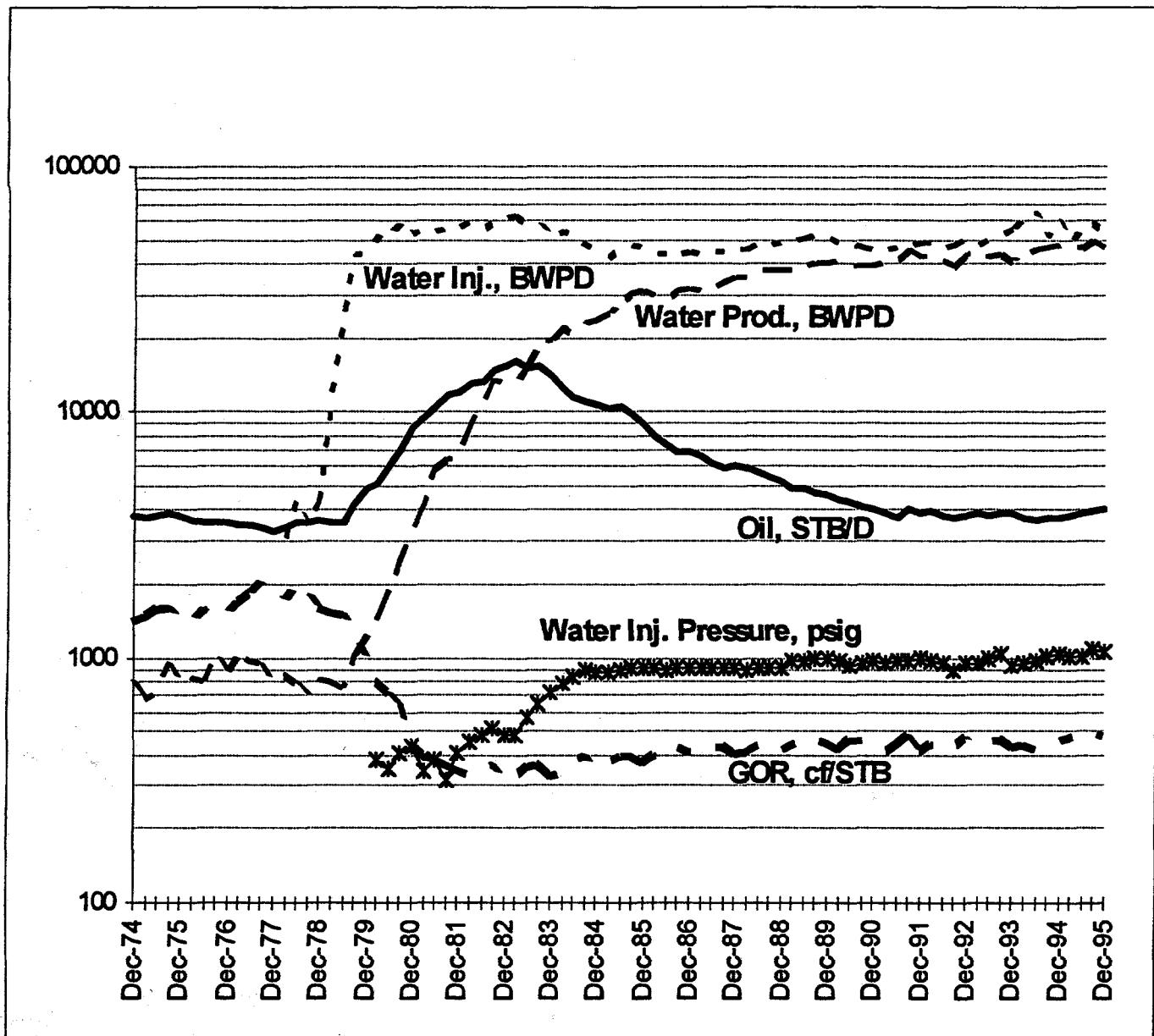


Fig. 2: Central Vacuum Unit production and injection history. Textbook waterflooding character.

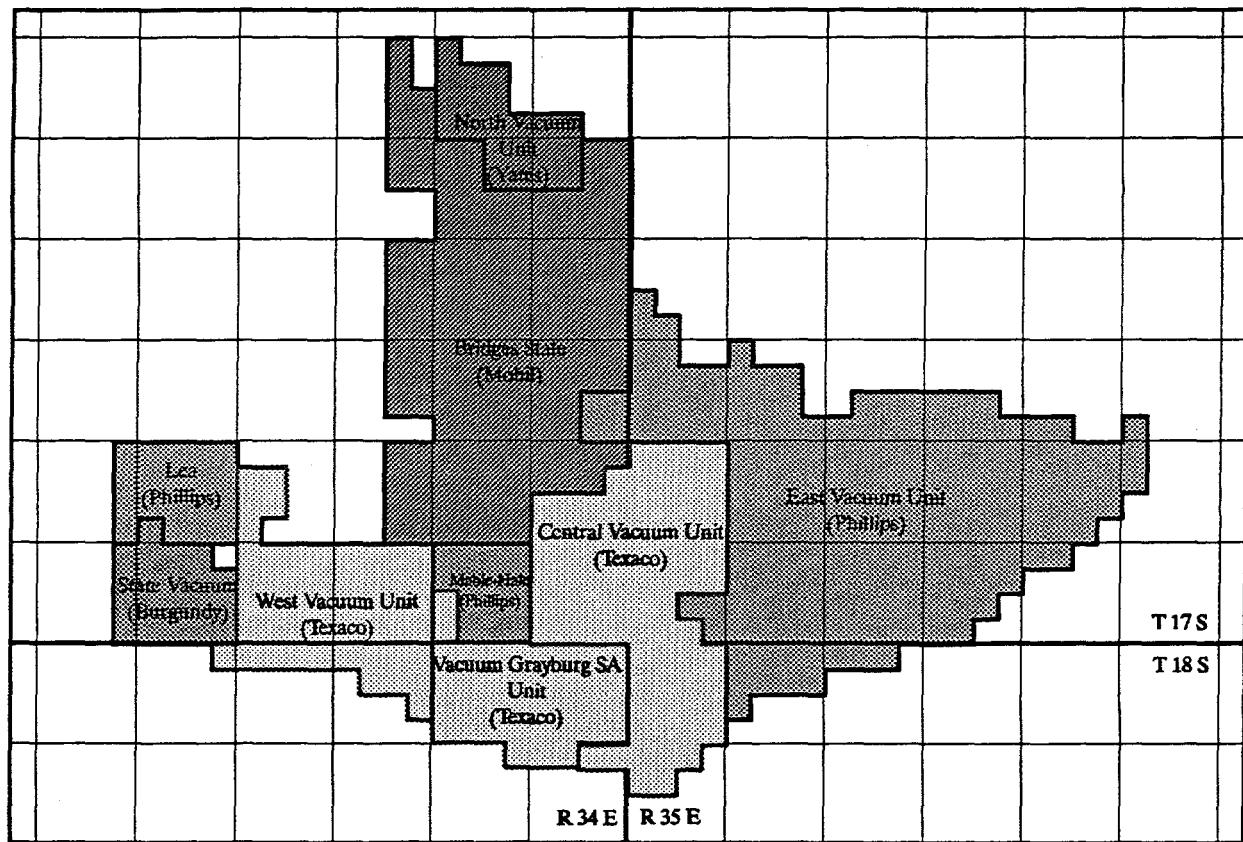


Fig 3: Unitized Acreage of Vacuum Field, Lea Co., New Mexico.

Geology

The Vacuum field lies on the margin between the Northwest Shelf and Delaware Basin (Fig. 4). Production is primarily from the Permian Guadalupian age San Andres formation. Less than 15% of the Unit's OOIP is located in the overlying Grayburg formation. The San Andres is composed of cyclical evaporites and carbonates recording the many "rises" (transgressing) and "falls" (regressing) of sea level occurring around 260 million years ago in a climate very similar to the present day Persian Gulf. The San Andres pay zone is divided by the Lovington sand member. The Grayburg formation is composed of cyclical carbonates and sands. The oil has been trapped in porous dolomites and sands that developed on a structural high. The productive intervals are sealed by overlying evaporites. Stratigraphically to the north, the porous dolomites pinch out into non-porous evaporites and evaporite filled dolomites. The porous zones are thinning and dip below the free oil-water contact (~4,700 ft.) in the southerly, basinward direction. A structural map is provided in Fig. 5.

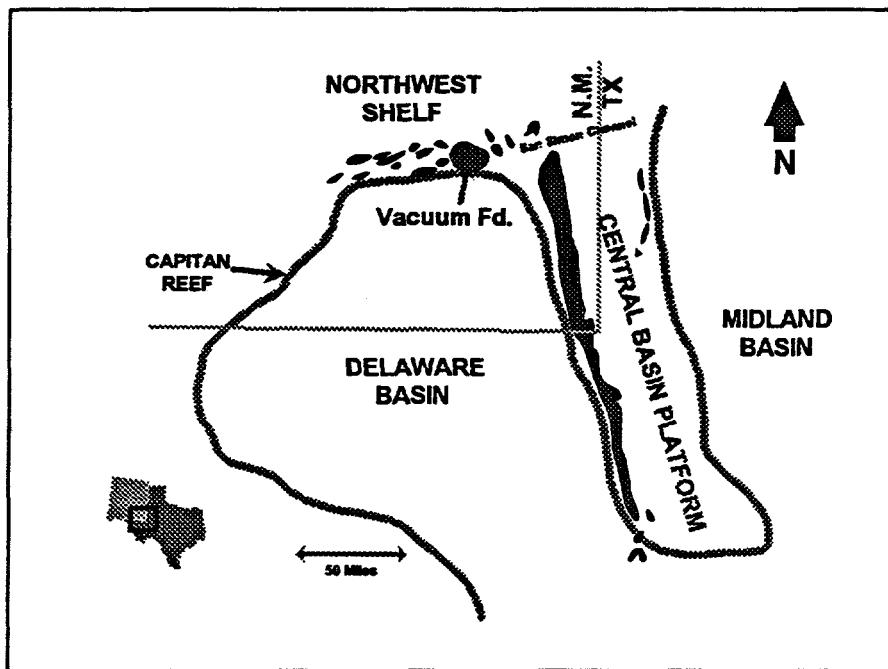


Fig. 4: Permian Basin and relative position of Vacuum field.

STRUCTURE MAP

TOP OF GRAYBURG DOLOMITE

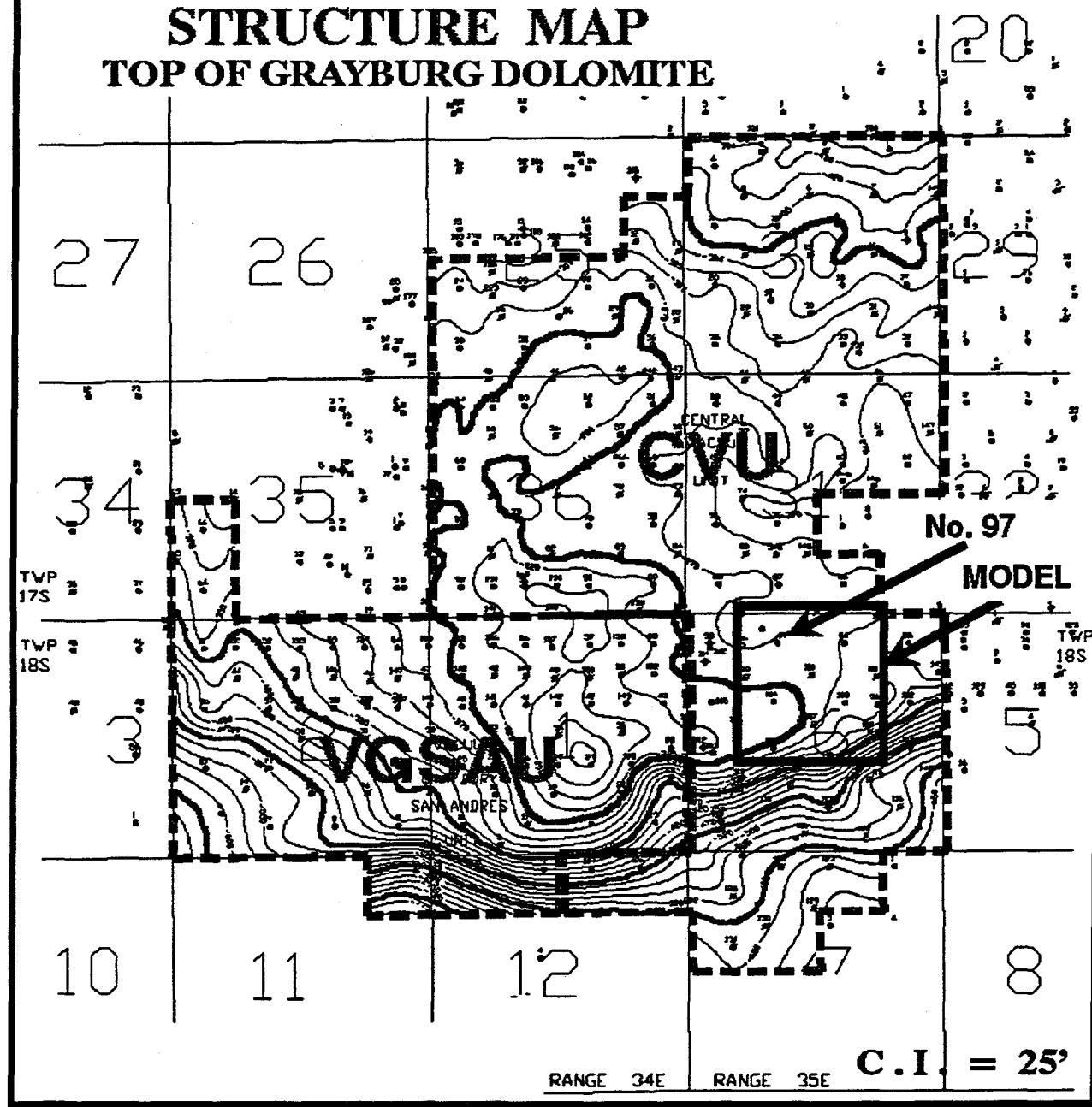


Fig. 5: Limits of Central Vacuum Unit with structural contours on Grayburg Dolomite. Shelf-Basin margin

Lithologically, the Grayburg formation consists of relatively dense dolomite with some anhydrite. It contains interbedded dolomitic sand stringers. The San Andres formation consists of dense medium crystalline and oolitic dolomite with some anhydrite. The pay is a fine to medium crystalline oolitic dolomite with slight fracturing and some solution cavities. Productive intervals consist of a series of permeable beds separated by relatively impermeable strata. The impermeable strata extend over large areas of the field and are believed to serve as effective barriers to prevent cross-flow between the permeable beds. The gross pay would be characterized as heterogeneous.

The Grayburg/San Andres formations produce a 38.0° API oil from an average depth of 4,550' within the CVU. The original water-free oil column reaches as much as 600' in height. Porosity and permeability in the pay interval can reach a maximum of 23.7%, and 530 md, respectively. The porosity and permeability over the gross pay interval averaged 6.8% and 9.7 md, respectively. Based on core studies, the net productive pay averages 11.6% porosity and 22.3 md. Although current saturations in the near wellbore vicinity have not been directly measured, core studies suggest typical residual oil saturations to waterflooding in swept zones to be in the range of 30-35%. Oil saturations in poorly swept zones, created by the heterogeneous architecture of the reservoir, could approach initial conditions. Hypothetically, this leaves a significant volume of uncontacted and immobile oil in the near wellbore vicinity of producing wells, which is the target of this CO₂ H-n-P process.

Brief of Project & Technology Description

This project has two defined budget periods. This report concludes a discussion of work predominantly completed and covered in the 1994 Annual Report, and work to-date under the second budget period. The first budget period primarily involved tasks associated with reservoir analysis and characterization, characterizing existing producibility problems, and reservoir simulation of the proposed technology. The near-term emphasis was to, 1) provide an accurate distribution of original oil-in-place on a waterflood pattern entity level, 2) evaluate past recovery efficiencies, 3) perform parametric simulations, and 4) forecast performance for a site-specific field demonstration of the proposed technology. The second, and final budget period incorporates the actual field demonstration of the technology.

It was anticipated that detailed reservoir characterization and a thorough waterflood review would help identify sites for the field demonstration(s). Numerical simulation would help define the specific volumes of CO₂ required, best operational practices, and expected oil recoveries from the demonstration sites.

Basic Theory and Objective. Under certain conditions the introduction of CO₂ can be very effective at improving oil recovery. This is most apparent when operating at pressures above the minimum miscibility pressure (MMP) of the system. As depicted in Fig. 6, recovery efficiencies are notably less under immiscible conditions.

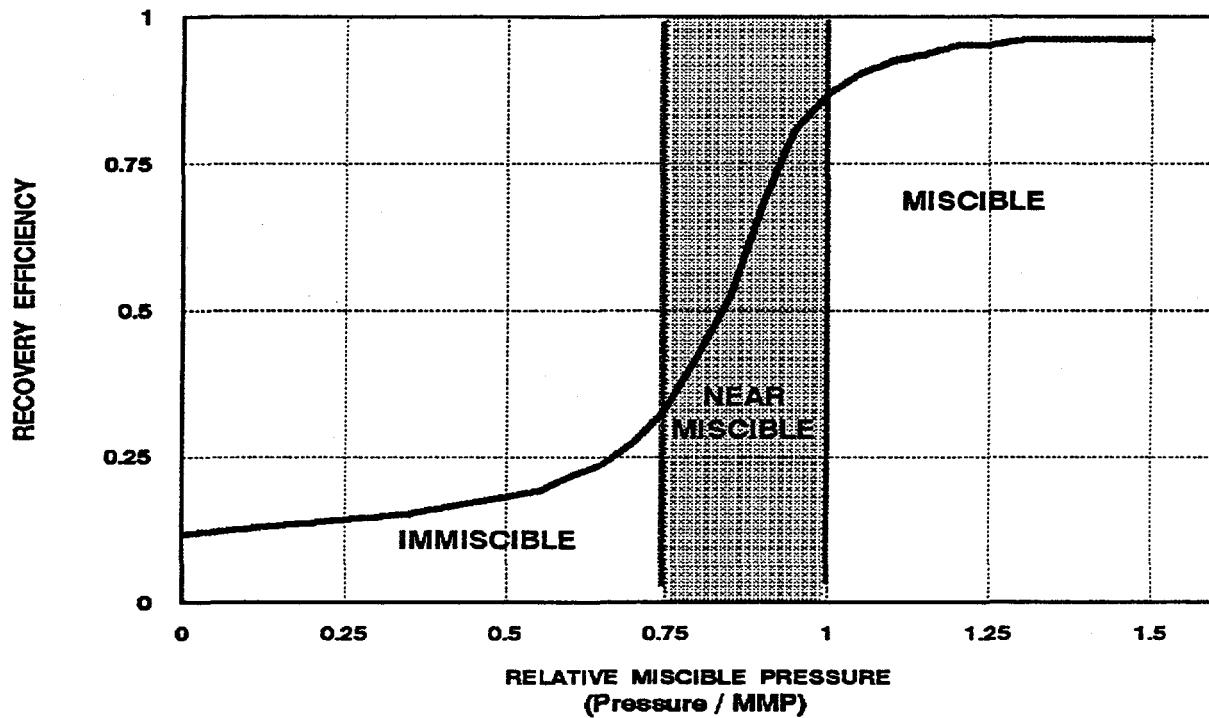


Fig. 6: Generalized Recovery Efficiency vs. Relative Minimum Miscibility Pressure.

The CO₂ H-n-P process has traditionally been applied to pressure depleted reservoirs. The CO₂ is injected down a production wellbore in an immiscible condition. Theoretically the CO₂ displaces the majority of the mobile water within the wellbore vicinity, while bypassing the oil-in-place. The CO₂ then absorbs into both the oil and remaining water. The water will absorb CO₂ quickly but only a relatively limited quantity. Conversely, the oil can absorb a significant volume of CO₂ although it is a much slower process. For this reason the producing well is shut-in for what is termed a soak period. This soak period is typically 1-4 weeks depending upon fluid properties and reservoir conditions. During this soak period the oil will experience swelling, viscosity and interfacial tensions will decrease, and the relative mobility of the oil will therefore increase. Once the well is returned to production, the swelled oil will flow toward the wellbore (pressure sink). Incremental production normally returns to its base level within six months. Previous work has shown that diminishing returns would be expected with each successive application. Most wells are exposed to no more than two or three cycles of the CO₂ H-n-P process. Fig. 7 visually illustrates the proposed CO₂ H-n-P process.

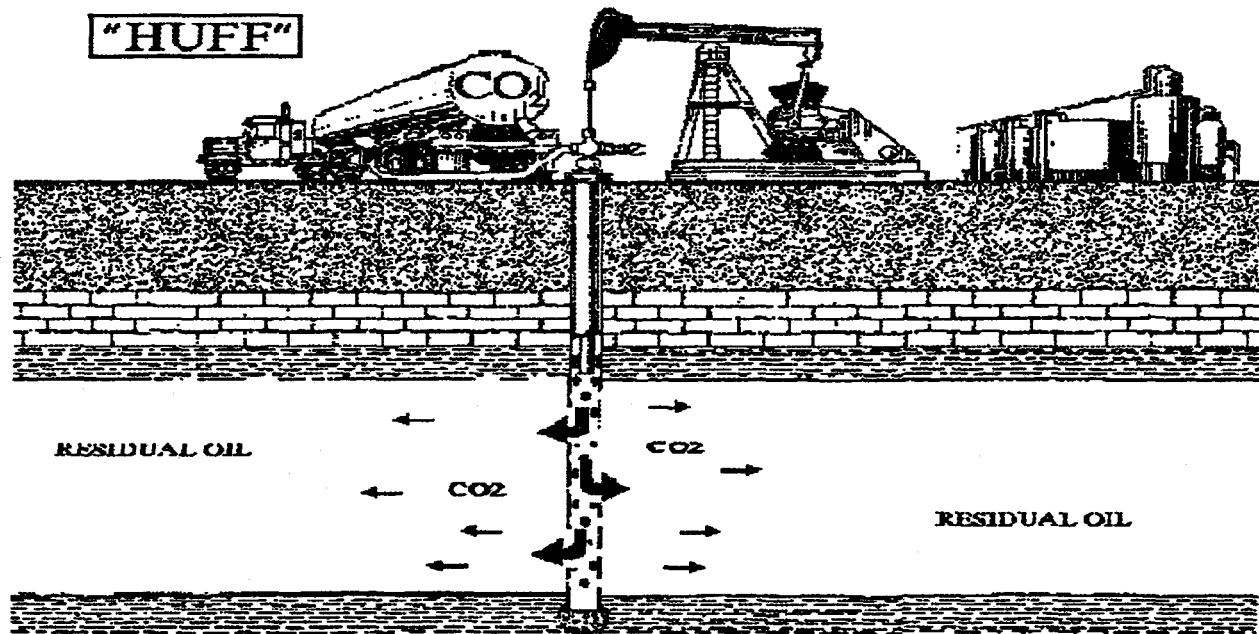


Fig 7a: Injection or "Huff" phase of hte Project

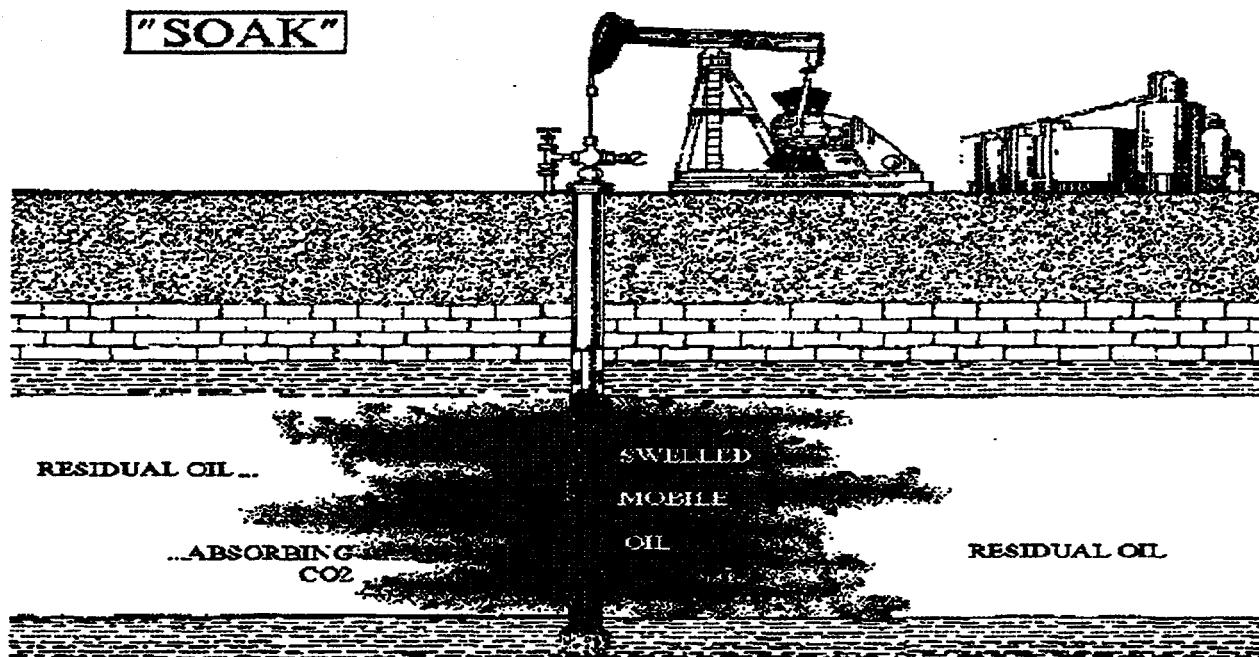


Fig. 7b: The "Soak" phase of the Project.

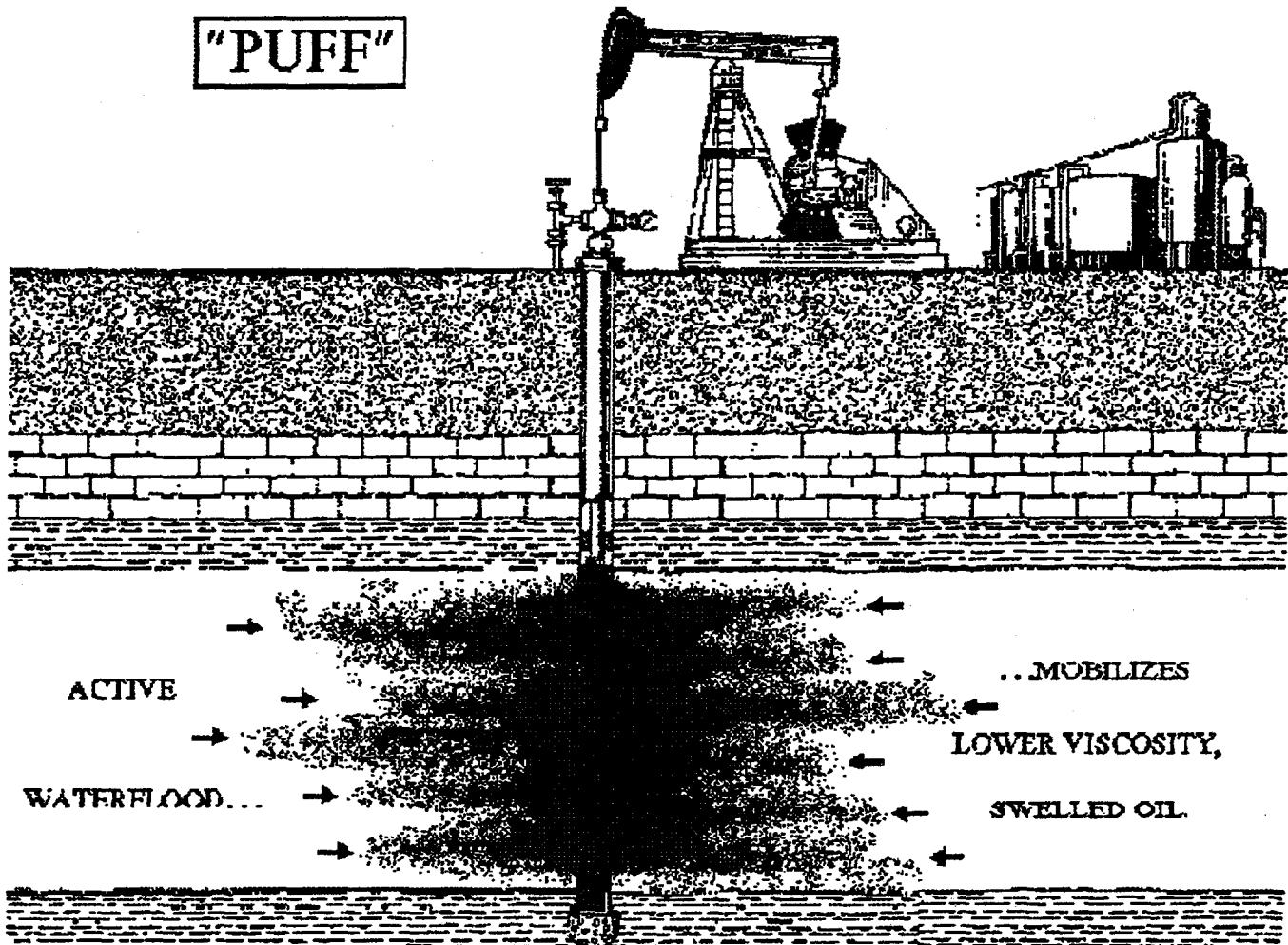


Figure 7c: The production or "Puff" phase of the Project

The vast majority of field trials have been conducted in low-pressure environments. Trials in moderate water-drive reservoirs have met with limited success. Fig. 8 shows a linear relation between these reservoir-drive mechanisms and recovery efficiency developed by TEPI from Gulf-Coast sandstone reservoir trials. The Drive Index is simply a measure of the contribution of reservoir-drive mechanisms for a given reservoir. The relationship depicted suggests that an operator should avoid higher pressure water-drive reservoirs, or in the case of CVU-waterfloods.

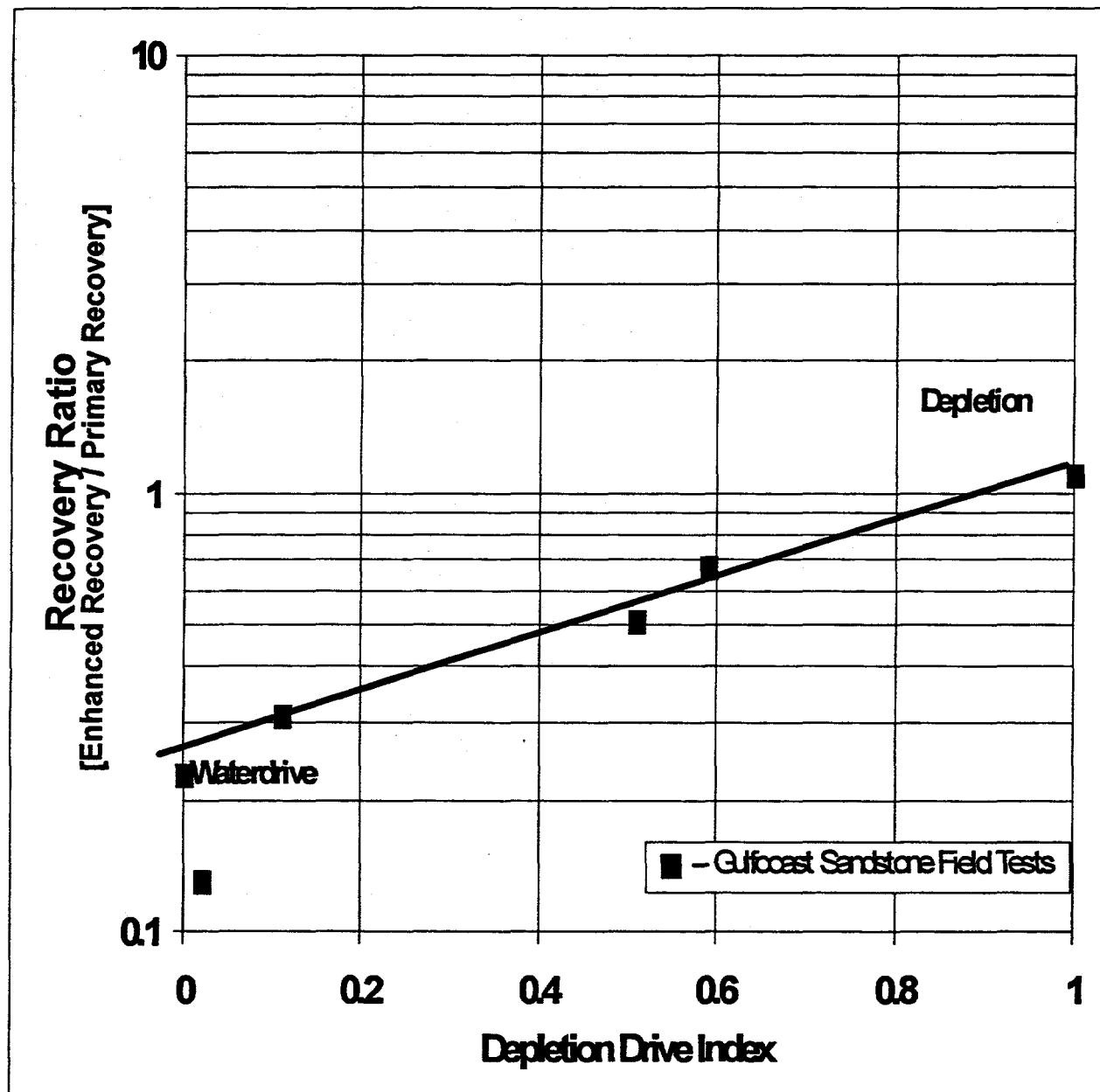


Fig. 8: Relation between Drive Index and Recovery Efficiency of the CO₂ H-n-P process. Developed from Gulf-Coast sandstone reservoir field trials.

Unfortunately, as with the case at CVU, major oil reserves available to Permian Basin operators are associated with maturing waterfloods.

After further review of Fig. 6, it was hypothesized that CO₂ H-n-P recovery efficiencies might be improved in the waterflooded environment by utilizing immiscible injection steps and miscible, or near-miscible production steps. The near-wellbore vicinity of producing wells is the pressure sink in the system. Further, it might be possible to gain an advantage in certain reservoir environments by temporarily ceasing offset water injection—creating somewhat of a pressure depletion environment. If an operator could inject in an inefficient manner, manipulating pressures and rates, such that a limited amount of oil was mobilized and/or fingering of the injectant occurred, then a 2-3 fold improvement in recovery efficiencies might be obtained. Once a given volume of CO₂ was injected, the offset injection could be restarted. The pressure in the near-wellbore vicinity could increase to, or exceed, MMP conditions during the soak due to the active waterflood. Under these conditions, a more significant swelling of the oil would be experienced in the near-wellbore producing area than in a pressure-depleted reservoir. The no-flow pressure boundary of the waterflood pattern would also serve to confine the CO₂, reducing leak-off concerns. When the well is returned to production, the mobilized oil would be swept to the wellbore by the waterflood. Energy introduced to the typical pressure depleted reservoir normally would dissipate away from the subject wellbore, further reducing efficiency. A study was initiated to investigate the possibilities.

DISCUSSION

Work is complete on the reservoir characterization components of the project. Macro zonation exists throughout the study area and cross-sections are now available. The Oil-Water Contact has been defined. Laboratory capillary pressure data was used to define the initial water saturations within the pay horizon. The reservoir's porosity distribution has been enhanced with the assistance of geostatistical software. Three-Dimensional kriging created the spacial distributions of porosity at inter-well locations. Artificial intelligence software was utilized to relate core permeability to core porosity, which in turn was applied to the 3-D geostatistical porosity gridding. An Equation-of-State was developed and refined for compositional simulation exercises. These topics dominated the 1994 Annual Report. Some final reservoir characterization comments regarding variances between geostatistical findings, and the waterflood review are provided in this 1995 report. Additionally, the findings from the parametric simulations, site-specific simulation history match and forecast, and field demonstration of the CO₂ H-n-P process are provided.

Geostatistical Realizations

The geostatistical portion of the project has been completed. The majority of this work was consummated and reported on during 1994.¹² Geostatistics, along with other more common approaches, were used to distribute wellbore porosity data to interwell locations (cells) within the geological model. Krigged porosity values were generated using Texaco's Gridstats program. Normalized wireline porosity data from 322 wells in the project area were input to the program, along with picks for the top of the Grayburg Dolomite, Grayburg Sandstone, and San Andres. This exercise was expected to provide a more realistic distribution of the data than the typical

algorithm used in standard mapping software. Initial geostatistical results proved too conservative relative to current and forecast recoveries. However, continued investigation into the impact of various inputs resulted in relatively similar results. As it turned out, the difference between the geostatistics and other approaches stemmed from a mis-formatted datafile. The following table (Table 1) compares the three methods of porosity distribution and the resulting OOIP. The previously accepted OOIP determination suggested 225.0 MMBO. The distribution of the original hydrocarbon accumulation, as determined by the three approaches is provided in Fig. 9.

Table 1: Comparison of Geostatistical approaches relative to OOIP calculations.

MODEL TYPE	OOIP CENTRAL VACUUM UNIT
STRATAMODEL DETERMINISTIC (POWER FACTOR = 2)	209.6 MMBO
STRATAMODEL STATISTICAL (POWER FACTOR = 5)	201.4 MMBO
GRIDSTATS (Texaco Geostatistics Software)	211.1 MMBO

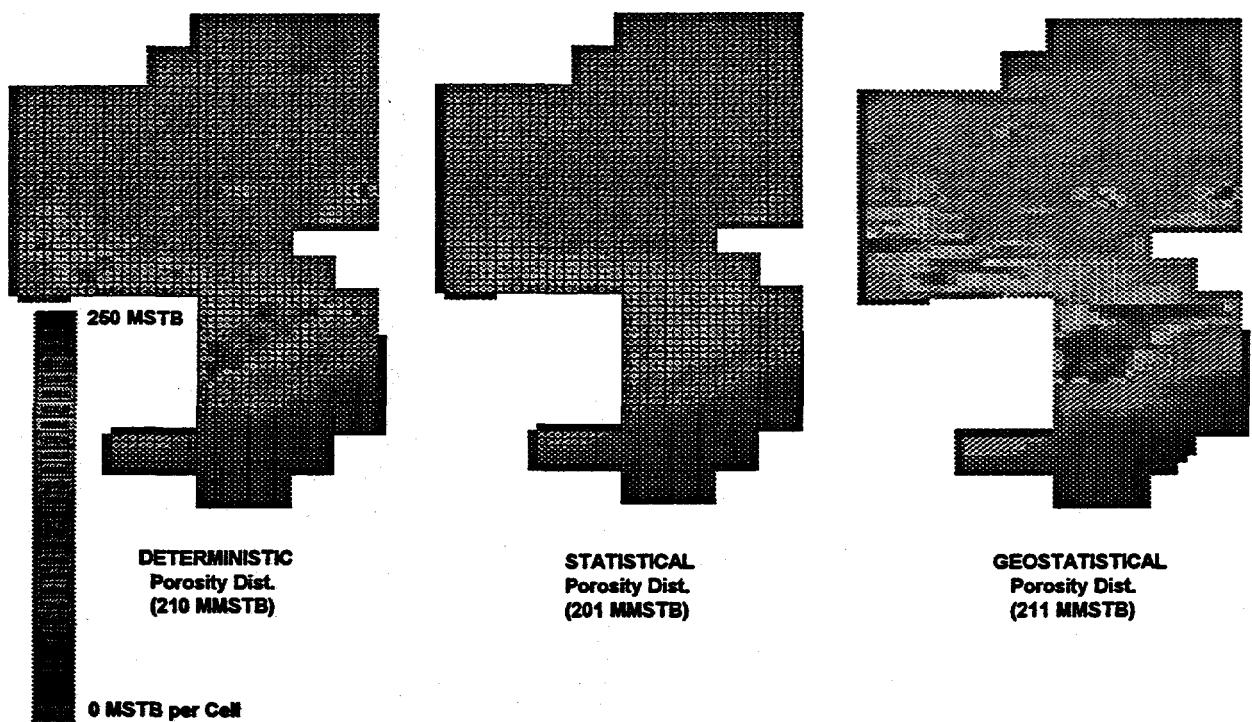


Fig. 9: Comparison of OOIP distribution based on three investigations.

The neural network, which was introduced in earlier reports, was applied to the porosity distributions to define the permeability. Capillary pressure data, also previously reported, was combined and used in calculating the OOIP reported above.

Resulting OOIP calculated from the geostatistical (Texaco's Gridstats program) derived porosity compares favorably to that using the distributions (deterministic and statistical) within the Stratamodel program. The lower value for the Stratamodel Statistical (Power Factor=5) model was to be expected. The porosity values of actual wireline measurements are not maintained at

wellbore cells with this particular approach. The resulting calculations tend to represent the reservoir flow units as a more continuous architecture, with lower porosity in any given zone of comparison (i.e. the data is heavily averaged). The Stratamodel Deterministic and GridStats (geostatistics) approaches were quite similar in OOIP calculations. But, it is only the geostatistical approach that does not rely heavily on any user defined input (power factor for scaling). Had the investigators chosen different scaling factors in Stratamodel, the results could have been quite variable, or the Stratamodel Statistical approach could have even had a similar result to the other two. Both the Geostatistical and Stratamodel Deterministic approaches match fairly well with the estimated ultimate recovery forecast trends. Since no flow simulation was planned for the large Project study area, no conditional simulation was done--all grids were made using kriging.

Attention in the first half of 1995 refocused on a smaller study area which encompasses the site-specific simulation area and impending initial field demonstration(s). The geostatistical exercise was repeated in this area for added modeling detail. A total of twenty stratigraphic porosity grids were made for this smaller study area. Five zones were created by kriging, and the same five zones by three successive conditional simulations. The five gridded zones are a 13 layer grid for the Grayburg Dolomite, a 7 layer grid for the Grayburg Sandstone, a 30 layer grid for the Upper San Andres, a 15 layer grid for the Lovington Sandstone, and a 90 layer grid for the Lower San Andres. Each cell is 132' X 132' on a side. The layers are approximately 4.00' thick. This model covers that same vertical component of gross pay as the larger study, after excluding some non-pay footage from the bottom of the model. The site-specific model for compositional simulation was extracted from this work.

Waterflood Review

A proper review of past operations is not complete without a comparison to the initial hydrocarbons in the formation. The procedures for calculating Original Oil-In-Place (OOIP) within Stratamodel software were developed and tested. OOIP was calculated for each cell in the model. Calculating OOIP in this manner required porosity, permeability, and initial water saturation, S_{wi} values for each cell in the model. Porosity was derived from the distribution of porosity data from each well location. Permeability was determined for each cell using the Neural Network described in previous reports. Initial water saturation was calculated for each cell using the Leverett "J" function (described in earlier reports). Polygons for unit boundaries and waterflood patterns were added to the model. These polygons allowed summation of OOIP for specific areas and individual waterflood pattern review. Details of this work were previously supplied.¹² Summation by stratigraphic sequence is also possible, allowing each of the five sequences to be summed individually. Many parameters, such as net pay, hydrocarbon pore volume, efficiency's, etc. were investigated and mapped. Many of these parameters have been included in Appendix "A" of this report in both Tabular and Figure format.

Current observations are that overall, either, 1) the property is experiencing ultimate recovery efficiencies above normal, at approximately 44.8% OOIP, 2) the OOIP is too low, or that 3) two independent approaches to estimating ultimate recoveries, although equivalent in findings, resulted in erroneous forecasts. Investigations continued during the later half of 1995. The site-

specific modeling helped address this issue during the history matching phase. The history matching went very smoothly. This is believed to be due to the detail provided in the geologic model, coupled with the initialization parameters developed within this study. The simulation suggests that the calculation of, and distribution of hydrocarbons is good. Overall, volumes and efficiencies fit with structural and geologic trends. Therefore, it is inferred that the ultimate recovery efficiency is above normal when compared to other San Andres waterfloods.

A review of waterflood efficiencies was conducted. It was anticipated that this detailed review would allow proper selection of the field demonstration site(s) for the proposed technology. The results of the parametric simulation studies were to be coupled with the waterflood review information. The intent was to be able to select a sufficient variation in reservoir conditions/character to support the parametric studies findings. In turn, this information would ultimately assist in developing guidelines to assist operators in selecting candidate sites based on this information and actual field trials. The waterflood review was performed parallel to the parametric simulation exercises which eventually concluded that reservoir characterization has relatively limited impact on this near-wellbore process as it relates to the CO₂ H-n-P (see discussion under Parametric Simulation topic). Following the actual demonstration, this data may still prove beneficial to the analysis.

Based on review of the available data, a site-specific model area was selected. It is located in the northern area of Section 6, T18S - R35E, Lea County, New Mexico (Fig. 5). This model area represents average reservoir conditions known to exist within the Project study area. It includes four (4) of the original 40-acre 5-spot injection patterns. This model area was drilled on a 10-acre well spacing -- providing modern logging suites in early 1995. The size of the model allows for the potential to analyze results from more than one field demonstration. This configuration was selected as a safety precaution, should the initial site fail mechanically. The data helped refine the model and provides a future measure to the geostatistical efforts. The drilling was not part of the cost-share DOE project.

Compositional Simulation Study

The reservoir characterization work¹² was incorporated into models for computer simulation. Western Atlas' VIP-COMP Simulation software was utilized. An equation-of-state (EOS) with nine pseudocomponents was developed using the Zudkevitch-Joffe-Redlich-Kwong approach to represent interactions between CO₂ and oil.¹² Extra efforts were made at this stage to assure an adequate match of phase properties, including CO₂ densities over an anticipated wide-pressure range. The EOS was able to match the behavior of slim-tube tests¹³ at, above, and below the MMP of 1,250 psia. This added credibility to the EOS and was important since the CO₂ would be in contact with hydrocarbons over a wide pressure range.

A parametric simulation study of the CO₂ H-n-P process was employed to identify reservoir parameters that might be favorable or unfavorable to the process and to provide insight into the best operational procedures. The results from the parametric study were incorporated into a site-specific simulation which was used for history matching the waterflood and forecast recoveries.

Parametric Simulations.¹⁴ A radial model with 25 grid cells in the radial direction was used. The model employed geometrical spacing between the grids but included local grid refinement for better definition near the wellbore. An injector was placed in the outside radial grid so waterflooding could be simulated and pressure in the model maintained. Porosities, saturations, and net pay were representative of the site selected for the field demonstration. Relative permeability curves obtained from laboratory measurements were used.

In some previous H-n-P's in a waterflooded environment, the total liquid production rate increased.⁶ This increase represented the majority of incremental H-n-P oil. However, there is no mechanism in a simulator to cause an increase in total liquid production over an extended period of time. In this study, an attempt was made to keep the steady total liquid production rate constant before and after the H-n-P. This made it necessary to operate the simulator sometimes with a well rate constraint rather than a bottom-hole pressure constraint.

Parameters Investigated. The reservoir parameters investigated in the study were the degree of reservoir heterogeneity and the magnitude of the watercut at the start of the H-n-P. The sensitivity to the number of layers in the model was also investigated as part of the study of the effects of reservoir heterogeneity. The operational parameters investigated were the CO₂ slug size, the CO₂ injection pressure (and rate) during the huff, the soak time, the gas production rate during the puff, and the number of H-n-P cycles. For consistency, most of the study was done using a slug size of 25,000 McfCO₂. A slug size of 25,000 McfCO₂ provides about 80 McfCO₂ per foot of net pay for the cases studied here.

Simulator Limitations. Commercial reservoir simulators normally do not directly incorporate a number of the mechanisms which have been identified or suggested as being present in the CO₂ H-n-P process. As part of this exercise, methods were identified which could be used to indirectly compensate for the absence of potentially important flow mechanisms in the simulator. These included primarily increases in the gas-oil capillary pressure to very large levels to approximate diffusion during the soak period and increases in the oil relative permeability curve (and even reductions in the residual oil saturation) during the puff to approximate suggested oil relative permeability hysteresis. The VIP-COMP simulator can also include directional relative permeability so that a decrease in the gas relative permeability can be modeled as desired. Diffusion tends to bring oil back toward the well during the soak period, and an increase in the oil relative permeability increases oil production. Recovery efficiency, or CO₂ utilization, in this parametric study could have been improved if these options had been incorporated in the predictions. However, they were not invoked during this study but were instead left to be used as needed for future history matching of the project.

Typical H-n-P Behavior. Typical performance for a 25,000 McfCO₂ injection is shown in Fig. 10. Following a soak period, a typical case showed a large increase in the oil rate beginning about 10 to 15 days after the well was placed back on production. The peak oil rate was typically 2 to 5 times the base rate. Prior to the peak response time, the production was primarily gas (mostly CO₂) with little water or oil. A large percentage of the CO₂ which had been injected was produced back before the oil peak. After the peak, the oil rate diminished rapidly with time, returning to the base rate within 40 to 80 days. The incremental oil recoveries were typically

between 1.5 to 3.0 MSTB. Good CO₂ utilizations were in the 10 Mcf/STB range, which are similar to the factors for standard CO₂ floods and are much greater than the factors of about 1 Mcf/STB previously reported in the literature for H-n-P processes. However, as noted earlier, including additional flow mechanisms could improve the utility. The objective of the parametric study was to compare the relative effects of selected parameters rather than predict the actual performance. It should, however, be realized that factors of 1 Mcf/STB are extremely small. Because 1 McfCO₂ occupies about 0.5 reservoir barrels for the situation here, a utility of 1 Mcf/STB means that one reservoir barrel CO₂ would recover about two reservoir barrels of oil.

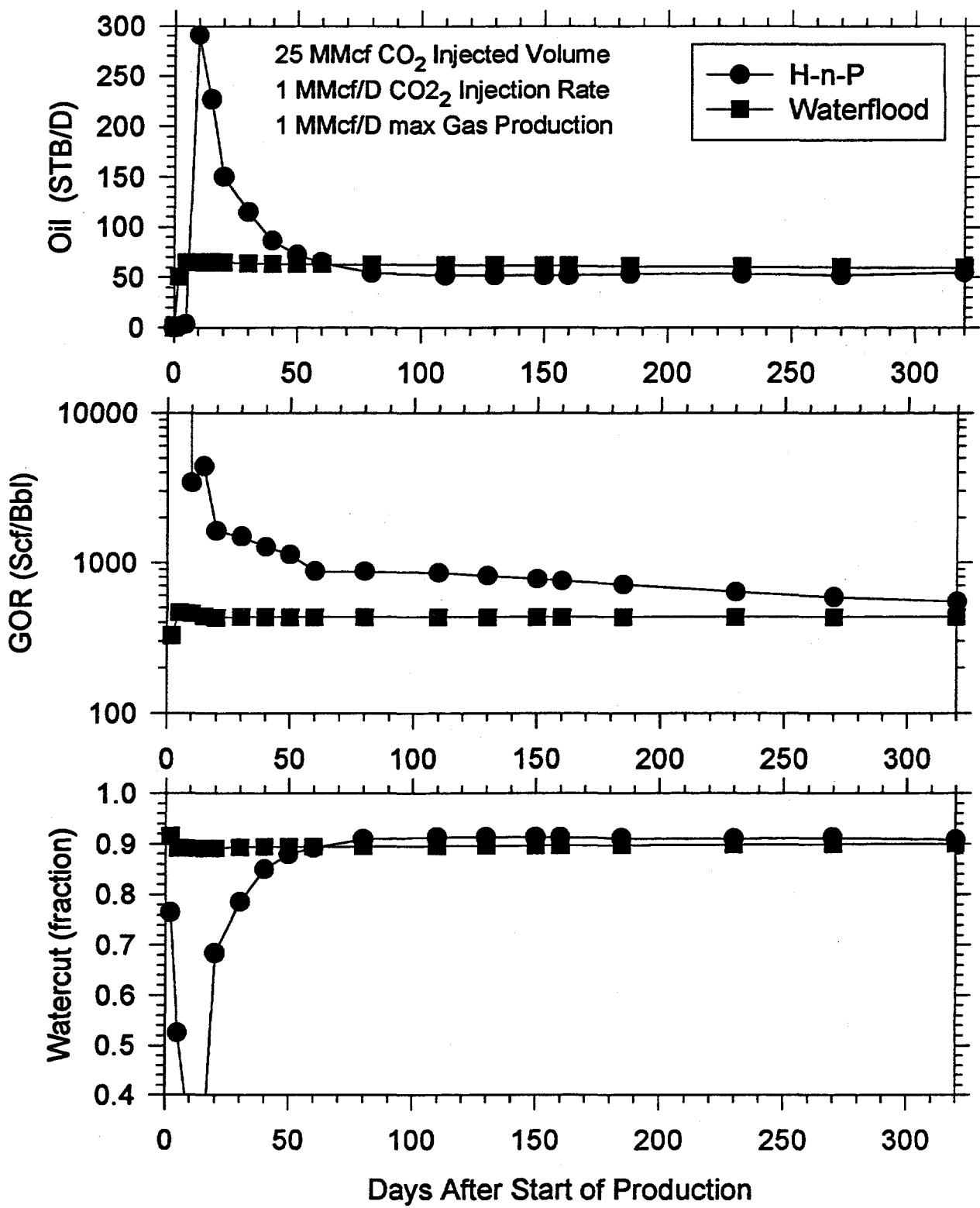


Fig. 10: Typical Simulated CO₂ H-n-P Performance.

Most of the CO₂ which was injected was produced back before or during the peak oil production. In the model, the CO₂ which was injected, except for the trapped volume, was ultimately produced back. The gas-oil ratio (GOR) did remain high for several months after the well was put back on production.

The water-oil ratio (WOR) returned to its base level soon after the oil production peaked. The WOR was not reduced for an extended period of time. Although a long-term reduction in the WOR would be desirable, such a change can not be expected. A previous study showed that the WOR is determined by the fractional flow of oil and water coming to the well from the larger part of the reservoir outside of the zone contacted by a process such as a H-n-P.¹⁵

Table 2
Effect of Important Parameters on Oil Production

	Incremental Oil (MMSTB)	Utility (Mcf/STB)
CO₂ Volume Injected, MMcf		
78	5.1	15.3
50	3.7	13.5
25	2.3	10.9
10	0.9	11.1
Watercut, Fraction [25 MMcf Case]		
0.85	1.4	17.9
0.90	2.3	10.9
0.97	3.1	8.1

Parametric Study Results. The effect of key parameters are shown in Table 2. Incremental recovery is defined as increased production over that of the waterflood after the well is put back on production.

The effect of reservoir heterogeneity was investigated by changing the base reservoir description. The layer permeabilities were altered. An initially very surprising result was that the H-n-P process was not found to be very sensitive to reservoir heterogeneity. This is directly opposite to standard CO₂ floods which are very sensitive to reservoir heterogeneity. An explanation can be provided by considering the differences in the standard CO₂ flood and the H-n-P. In a standard flood, high reservoir heterogeneity degrades performance because CO₂ inefficiently keeps channeling through zones in which the oil has already been recovered. In a H-n-P this does not happen. Rather, all the CO₂ which is injected, except for the trapped volume, is ultimately produced back from all the layers, even from the thief zones. All the zones are just processed one time. A thief zone does not degrade a H-n-P process unless the CO₂ permanently channels away. Reservoir heterogeneity does not appear to degrade the Huff-n-Puff process substantially unless there are very high permeability zones without vertical permeability. The presence of vertical permeability largely prevents high permeability streaks from degrading the process. A large amount of vertical permeability is not needed and values as little as 0.1 to 0.2 md are effective. The vertical permeability makes a layered system with heterogeneity more effective than a completely homogeneous system. If vertical permeability is present, the CO₂ enters the high permeability streaks but can move vertically into other layers. If there is no

vertical permeability, zones of very high permeability will degrade the process since the CO₂ is confined primarily to the high permeability layers.

An additional finding, which also indicates that reservoir heterogeneity is not critical for the H-n-P process, is that predicted H-n-P performance was not found to depend significantly on the number of layers used in the simulation model. Similar results were found with 1, 2, 5, and 12 layer models. Even though a one-layer model is completely homogeneous, the results from a one-layer model were typically within 20% of the results from multi-layer models. The results shown in Fig. 10 are from a one-layer model. Previous investigators have also suggested that one-layer models are sufficient for modeling H-n-P processes.^{8,16}

Another surprising result was that the H-n-P process in waterflooded (water drive) environments appeared to work better for wells with a higher water-cut. These wells have an oil saturation close to the residual oil saturation to waterflood. The incremental oil recovery was somewhat higher and the CO₂ utilization was somewhat lower for a high water-cut case. The peak H-n-P oil rate was not found to be a strong function of the prior watercut. Consequently, a well with a high water-cut showed a large relative increase in the oil rate.

As previously discussed, the original idea of the CVU H-n-P process was to try to inject the CO₂ below the MMP of 1,250 psia, and then let the pressure build during the soak period. However, the simulation model suggested that an operator could not inject the CO₂ below the MMP. For the CVU cases, the reservoir is above the MMP. Near-wellbore average pressure reached the MMP rather rapidly after beginning injection in this simple model. Furthermore, the pressure rapidly reached the MMP even when the well was shut-in without injection and when offset injection was stopped 15 days in advance. Oil recoveries in the CO₂ H-n-P process simulated here were not found to depend strongly on the injection pressure or rate. **Injection pressures** from the MMP to 3000 psia were investigated, and it was found that the process was not degraded significantly at successively higher pressures when above the MMP.

Limiting the gas production rate between 500 and 3,000 Mcf/D did not greatly affect the incremental oil production. It was found that slightly higher incremental recoveries occurred with the higher gas production rates.

The volume of incremental oil was found to depend on the volume of CO₂ injected. As the volume of CO₂ was increased, the incremental oil recovery was increased, but also the start of oil production during the puff was delayed.

In agreement with previous simulation studies, soak times longer than a few days did not produce different results.^{8,16} Current commercial simulation models may not adequately handle the soak period.

Multiple H-n-P cycles were not found to be very effective. The reason was that the main recovery mechanism was gas trapping, and the majority of trapping occurred in the first cycle. The repetitive application of the process was seen as unwarranted in the waterflooded environment.

Dominant Mechanism. Entrapment of CO₂ by gas hysteresis was found to be the dominant recovery mechanism. This study supports the conclusion of Denoyelle and Lemonnier that a trapped gas saturation is the main cause of incremental oil for a H-n-P in a light oil reservoir.¹⁷ The mechanisms of oil swelling and viscosity reduction are important in the production of the initial oil peak, but they do not result in permanent incremental oil. In the present study, if a trapped gas saturation generated by gas relative permeability hysteresis was not used in the H-n-P simulation, virtually no incremental oil was predicted. The trapped CO₂ in the H-n-P zone prevents the H-n-P zone from being resaturated with oil that is flowing toward the well from further out in the reservoir. What happens without a trapped gas saturation is that although the H-n-P initially produces oil from the affected region by reducing the oil saturation to very low levels, oil from further out in the reservoir enters the affected zone as it flows toward the well and re-establishes an oil saturation similar to the saturation before the H-n-P. In other words, without a trapped gas saturation, the oil and water flowing into the H-n-P zone return the oil and water saturations to the values that would have existed without a H-n-P. A trapped gas saturation prevents resaturation by oil.

In the simulator, a trapped gas saturation has a tendency to reduce the total liquid production rate. This effect was not used in the parametric studies or the site-specific forecast. For both these cases, an attempt was made to keep the steady total liquid production rate constant before and after the H-n-P by operating the simulator sometimes with a well-rate constraint rather than a bottom-hole pressure constraint.

Summary. Reservoir description was found not to be as important a parameter in a H-n-P as in a standard CO₂ flood. This indicates that most wells could be H-n-P candidates unless they have problems that would cause the CO₂ to channel permanently away. H-n-P operations can be flexible because H-n-P predicted performance was found to be similar over a range of injection pressures and gas production limits. Injection volume is an issue because recoveries were found to be related to the total CO₂ volume injected, similar to typical miscible floods.

Site-Specific Study.¹⁸ The model site covers 160 acres (four original 40-acre five-spot patterns) in the north half of Section 6 (outlined in Fig. 3). The model covers an area that was developed on 10-Acre spacing in early 1995. The site spans varying reservoir quality. The northwest pattern is more contiguous, and has exhibited textbook waterflood characteristics. The southeast quarter is more heterogeneous and has had a much poorer waterflood history. The model site covers the margin between the Northwest Shelf and the Delaware Basin. Producers are located on the periphery of the model. Four interior producers are considered candidates within the model area; however, CVU Well No. 97 was chosen as the most representative of the reservoir and is the only pattern comprehensively evaluated to date.

The 160-acre model was finely gridded with 26 rows and 22 columns (132 ft. × 132 ft.). Twelve layers were incorporated to model flow units identified by earlier geostatistics work. A cross-section through the model is provided in Fig. 11. Additional local grid refinement was imposed at the cell encompassing the producing wellbore in an effort to more accurately mimic the process.

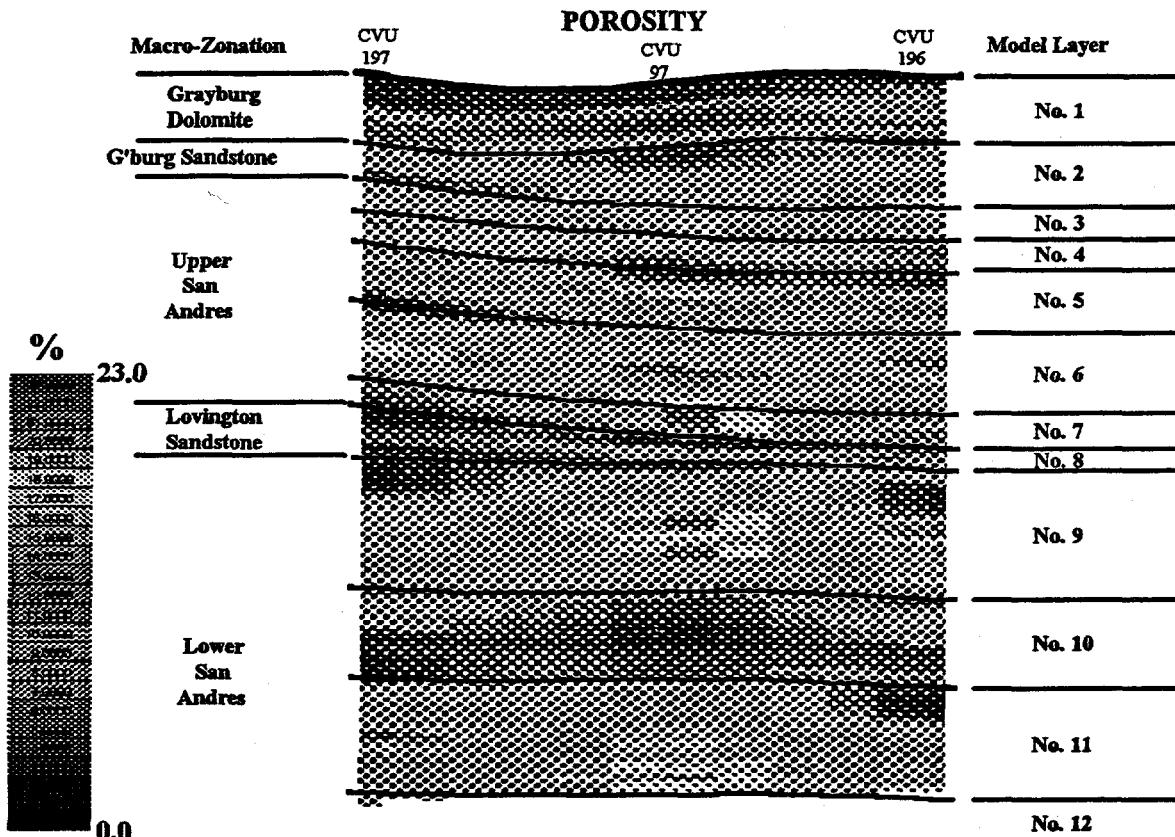


Fig. 11: East-West cross-section through Porosity model. Macro-zonation and model layer numbers identified.

A short investigation was performed to evaluate the significance of grid size and various finite difference approximations on predicted oil recovery. A clear significance of nine-point versus five-point finite difference approximations was found when dealing with a courser grid. Local grid refinement in this case did not appear to have a significant effect on oil recovery. A finer grid was made which resulted in similar recoveries for both the five-point and nine-point approximations. The conclusion of these initial exercises was that local grid refinement may not be necessary for a nine-point formulation. The benefits of local grid refinement to the analysis of near wellbore effects, such as pressure, which were expected to dominate much of the field demonstration were not specifically addressed. Local grid refinements were ultimately deemed necessary since the injected volume would otherwise only reflect changes in a single cell.

The full model contained 6,924 cells (6,864 cells, exclusive of local grid refinement). History matching the waterflooded period of 1978 (start of waterflood) through 1995 was performed. The historical oil rates were used as input to the simulator, and the water production rates were history matched primarily by adjustments in the oil relative permeability curve. Although the primary production is available, it cannot be accurately history matched with the current equation-of-state since it was developed from Pressure, Volume, and Temperature (PVT) studies on the waterflooded oil properties. No PVT data is available prior to waterflooding. The relative permeability adjustments were kept within the range of laboratory data. A forecast of the process was developed for a demonstration at CVU No. 97, and is provided in Fig. 12. Appendix "B" contains the Input and Output datasets from this exercise. A moderately large gas-oil capillary

pressure and trapped gas hysteresis were the only special relative permeability features used in developing the forecast. In addition, the steady total liquid production rate was kept constant before and after the H-n-P by operating the simulator with a well-rate constraint rather than a bottom-hole pressure constraint.

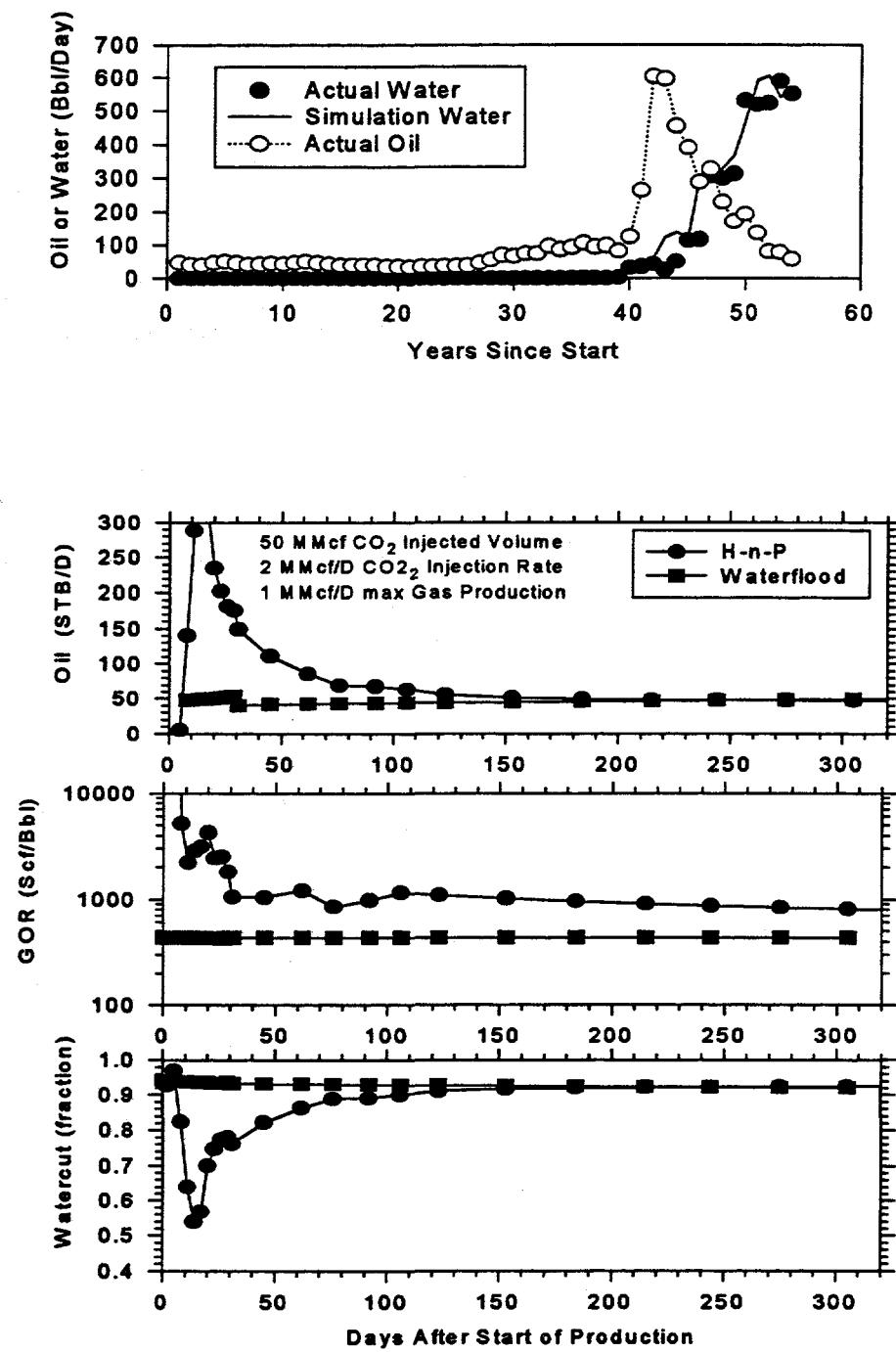


Fig. 12: Demonstration History Match (primary + secondary) and CO₂ H-n-P Prediction for CVU No. 97.

Field Demonstration

Even though simulation exercises suggested reservoir heterogeneity would not play a large role, a well with average reservoir characteristics of the CVU was desired. Additionally, the parametric study showed that a higher water-cut production stream would have a better CO₂ utilization ratio. CVU No. 97 was selected in part based on these guidelines. The well has several distinct, relatively thin, higher permeability flow units which are common within CVU. The remainder of the net pay is of average reservoir quality.

CVU No. 97 was drilled in 1938 to a depth of 4,725 ft. An open-hole completion was made with 7.0 in. casing set at 4,099 ft. Cement was circulated back up into the surface casing. This completion left 161 ft. of impermeable strata above the pay zone exposed in the 6.125 in. wellbore. Casing integrity or unknown thief zones have been cited in the literature to be primary causes of failure in other work. A casing-inspection log and cement-bond log revealed a competent wellbore. Additionally, there is no record of fluid production from, or losses to, the exposed non-pay interval at CVU.

A volume of 50,000 McfCO₂ was required. The volume was determined to be sufficient for the storage volume available in the near wellbore vicinity, yet small enough to reduce concerns of any loss of CO₂ beyond the interwell distance if the three higher flow-capacity zones took all the injectant. Based on average reservoir parameters, this volume would expose the reservoir to less than a 100 ft. radius of CO₂.

Downhole Operations. The production equipment was removed from the wellbore after tagging 10 ft. of fill material at total depth. Since the well had been acidized in recent months, no further remedial action was performed. An on-off tool and injection packer trimmed for CO₂ service was run on 2.875 in. coated tubing and set in the casing. Inhibited water was placed on the backside. Testing frequency was stepped up in the prior month to confirm a stabilized production trend.

Surface Operations. The theory of ceasing offset water injection was not strongly supported by simulation. However, recognizing that simplistic models may not have the capability to quantify this case, the offset injection was shut-in 17 days before CO₂ injection commenced at CVU No. 97.

CO₂ Storage/Injection Equipment. A pipeline alternative was investigated, but was found to be somewhat costlier for the near-term demonstration component of this project. The CO₂ transportation and pumping services were awarded to CO₂, Inc. out of Midland, Texas. The CO₂ was trucked 50 miles from a site near Allred, Texas. Each truck could haul 345 McfCO₂. Storage vessels were set in order to eliminate night deliveries. Approximately 145 round-trips were required for the project. The storage vessels were manifolded into a trailer mounted quintuplex positive displacement pump, with self-contained booster, which was connected to the wellhead. Injection rate and volume, temperature, and pressures were continuously recorded.

Test Separator. Frequent and detailed testing was planned for the duration of the project. Therefore, a dedicated horizontal, three-phase, skid-mounted test vessel was fabricated for the

demonstration and set at the well site. Data gathering was automated. Flowing tubing pressure, casing pressure, and temperature are monitored continuously. Liquid volumes are measured daily. Gas production rates and volumes are also being measured. Automated gas sampling provides a daily sample for gas chromatography. Liquid samples are initially gathered daily for visual inspection, API gravity determination and occasional compositional analysis. Testing frequencies will decrease with time. The well was connected to the separator with polyethylene pipe. The test separator dumps liquids through another polyethylene pipe to the existing production satellite.

Produced Gas Handling. One of the major hurdles this demonstration faced was disposal of the produced gas stream. Original plans fell apart when the existing gas purchaser committed to significant new gas contract volumes. The added volumes did not leave enough plant capacity for the CO₂ (acid gas) within the facility.

Air quality regulations would not permit venting the hydrocarbon enriched CO₂ stream to the atmosphere. A CO₂ processing facility, operated by Phillips Petroleum Company, was in operation on the offsetting lease (miscible CO₂ flood). A contract was consummated to temporarily dispose of the CO₂ contaminated gas production. An idle 6.0 in. gas line, which passed by both the demonstration site and a satellite at the offset CO₂ flood, was used to deliver the contaminated gas to the CO₂ processing facility. Polyethylene pipe was used at both ends to tie the delivery line into the satellite and test separator.

Initial Results. Injection was initiated November 13 and completed on December 7, 1995. Based on the offset miscible CO₂ flood injection rates and pressures, an average rate of 1,500 McfCO₂/Day was expected in the demonstration. Actual injection averaged 2,210 McfCO₂/Day over 23 days net injection. Two days (separate incidents) were lost to mechanical problems involving the injection pump. Injection line temperature fluctuated between -14°F and 20°F, averaging 3.4 °F. Wellhead injection pressure averaged 644 psig and did not exceed 817 psig.

Concern over the open-hole section, lower injection pressures and higher injection rates than expected prompted an injection profile once half the target volume was injected. The CO₂ was found to be distributed within both the Grayburg and San Andres formations. Although the injectant was confined to the pay zone, the distribution was somewhat weighted toward the Lower San Andres. The injectant was at the reservoir temperature of 101°F by the time it reached the bottom injection interval. The estimated average bottomhole injection pressure of 2,175 psig never approached the parting pressure of the formation (3,200 psig). It is doubtful that any part of the near-wellbore vicinity was able to maintain a pressure below the MMP of 1,250 psig as originally desired.

Offset producers were monitored on a regular basis for CO₂ breakthrough. Levels remained in the normal 4-5% background range.

Once the target volume was in place, offset water injectors were returned to active service. CVU No. 97 was shut-in for a 20-day soak period--6 days longer than plan due to labor issues. Wellhead pressure averaged 630 psig during the last week of injection and had increased steadily

to 889 psig during the soak period. Although common in the CVU water injectors, it is unknown if any cross-flow from higher permeability to lower quality zones occurred in the producing wellbore during the soak period.

CVU No. 97 was returned to active status under flowing conditions on December 27, 1995. Flowing tubing pressure averaged 631 psig with choke settings between 13/64 in. and 18/64 in. Initially, production averaged 901 Mcf/Day. Smaller choke settings produced an average rate of 409 Mcf/Day with no apparent effect on liquid hydrocarbon production. No appreciable water production has been seen although rates are beginning to increase. Compositional analyses of the gas stream are running at 94% CO₂. Liquid hydrocarbon production was initially too small to measure and began increasing on the third day. Samples are being collected and retained. The fluid is colorless, suggesting that lighter hydrocarbons are being effected. The well had achieved a 70 BOPD rate by the tenth net day of flow-back (average pre-demonstration was 68 BOPD). The rate should improve when the hydrostatic head is removed from the pay zone. Approximately 27% of the injected CO₂ volume has been produced. Simulation exercises suggest that the peak oil response will not occur until 60% of the CO₂ has been produced back.

Winter weather is hampering flowback, exasperating hydrate formation. An in-line heater was temporarily placed near the wellhead until liquid volumes increased sufficiently to eliminate the need. The gas flow line freezes in the evenings where liquids collect. The line has been leveled in an attempt to control the situation.

Fig. 13 provides the field demonstration history through January 18, 1995. Supporting data is provided in the Appendix "C". Monitoring continues with optimism toward a successful demonstration based on these early results.

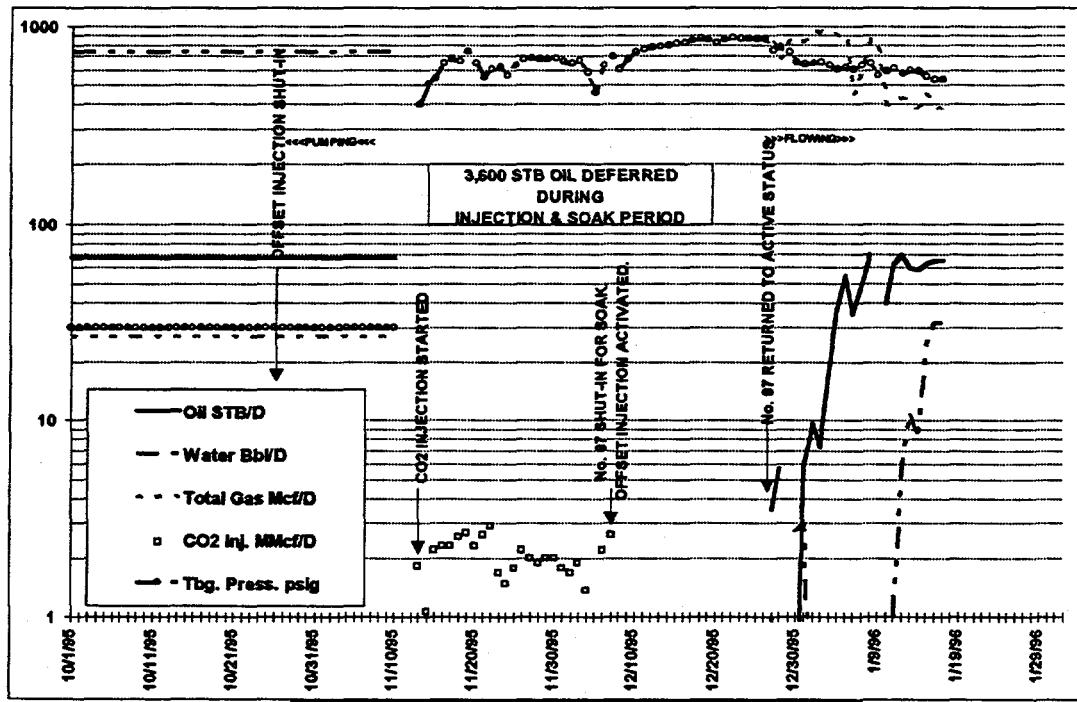


Fig. 13: CO₂ H-n-P Demonstration History.

Miscellaneous

An industry Consortium led by the Colorado School of Mines selected the Central Vacuum Unit as a site to conduct 4-Dimensional, 3-Component (compressional & shear) seismic studies. The project is attempting to monitor dynamic reservoir conditions associated with the introduction of CO₂ into the reservoir along with stress field changes. The information gained through this seismic demonstration complements the subject project. The information may provide necessary data for refinements to the reservoir model (layering, flow capacity, fracture orientation, etc.) and fluid characterization (saturations, fluid flow; etc.). Their consideration of the CVU as a demonstration site was made possible by the fact that the accumulation of data from this CO₂ Huff-n-Puff project is available in the public domain; obligated by the use of DOE funding. The 4D, 3C Seismic project is being conducted in parallel, at no cost to the DOE. The Consortium is expected to release details of the work by mid-1996.

Technology Transfer

Technology transfer activities during the 1995 period consisted of updates of project progress and findings through 1) a newsletter published by the New Mexico Petroleum Recovery Research Center, 2) Society of Petroleum Engineer publications and presentations, 3) Joint Project Advisory Team Meetings, and 4) GO-Tech, an Internet site jointly sponsored by the Petroleum Technology Trade Council and the Independent Producers Association of America.

Conclusions

A successful demonstration of the CO₂ Huff-n-Puff process could have wide application. The proposed technology promises several advantages. It is hoped that the CO₂ Huff-n-Puff process might bridge near-term needs of maintaining the large domestic resource base of the Permian Basin until the mid-term economic conditions support the implementation of more efficient, and prolific, full-scale miscible CO₂ projects.

Paramount to considering the technology is the need for adequate disposal or processing of the hydrocarbon laden CO₂ gas. Winter months add to the operational problems encountered with flowing hydrate prone wells.

Reservoir description was found not to be as important a parameter in a H-n-P as in a standard CO₂ flood. H-n-P predicted performance was found to be similar over a range of injection pressures and gas production limits. Recoveries were found to be related to the total CO₂ volume injected, similar to typical miscible floods. Gas trapping by hysteresis was found to be the dominant factor influencing recoveries.

A need for model refinement has been demonstrated by the differences between predictions and early results (injection rates & pressures). Monitoring of the CVU field demonstration continues. Early results do not provide enough data to make an informed opinion; the project continues under cautious optimism. Over the next several months, production will be monitored and history matched with the compositional simulator. The mechanisms investigated during the parametric simulation

exercise will be incorporated as warranted. Following a successful demonstration and associated history matching, the development of guidelines for the cost-effective selection of candidate sites, along with estimation of recovery potential, will be pursued. Additionally, the economic benefits of the proposed process will be reviewed.

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- 14 J. Prieditis, S.C. Wehner, et. al., "Quarterly Technical Progress Report, CO₂ Huff-n-Puff Process in a Light Oil Shallow Shelf Carbonate Reservoir", (1st Qtr. 1995), DOE No. DE-FC22-94BC14986, Apr. 21, 1995, Pg. 2.
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- 16 H.H. Hsu, R.J. Brugman, "CO₂ Huff - Puff Simulation Using a Compositional Reservoir Simulator", SPE Paper No. 15503, Presented at the 61st SPE Technical Conference, New Orleans, LA, (October 1986).
- 17 L.C. Denoyelle, P. Lemonnier "Simulation of CO₂ Huff 'n' Puff Using Relative Permeability Hysteresis", SPE Paper No. 16710, Presented at the 62nd SPE Technical Conference, Dallas, TX, (September 1987).
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*** APPENDIX ***

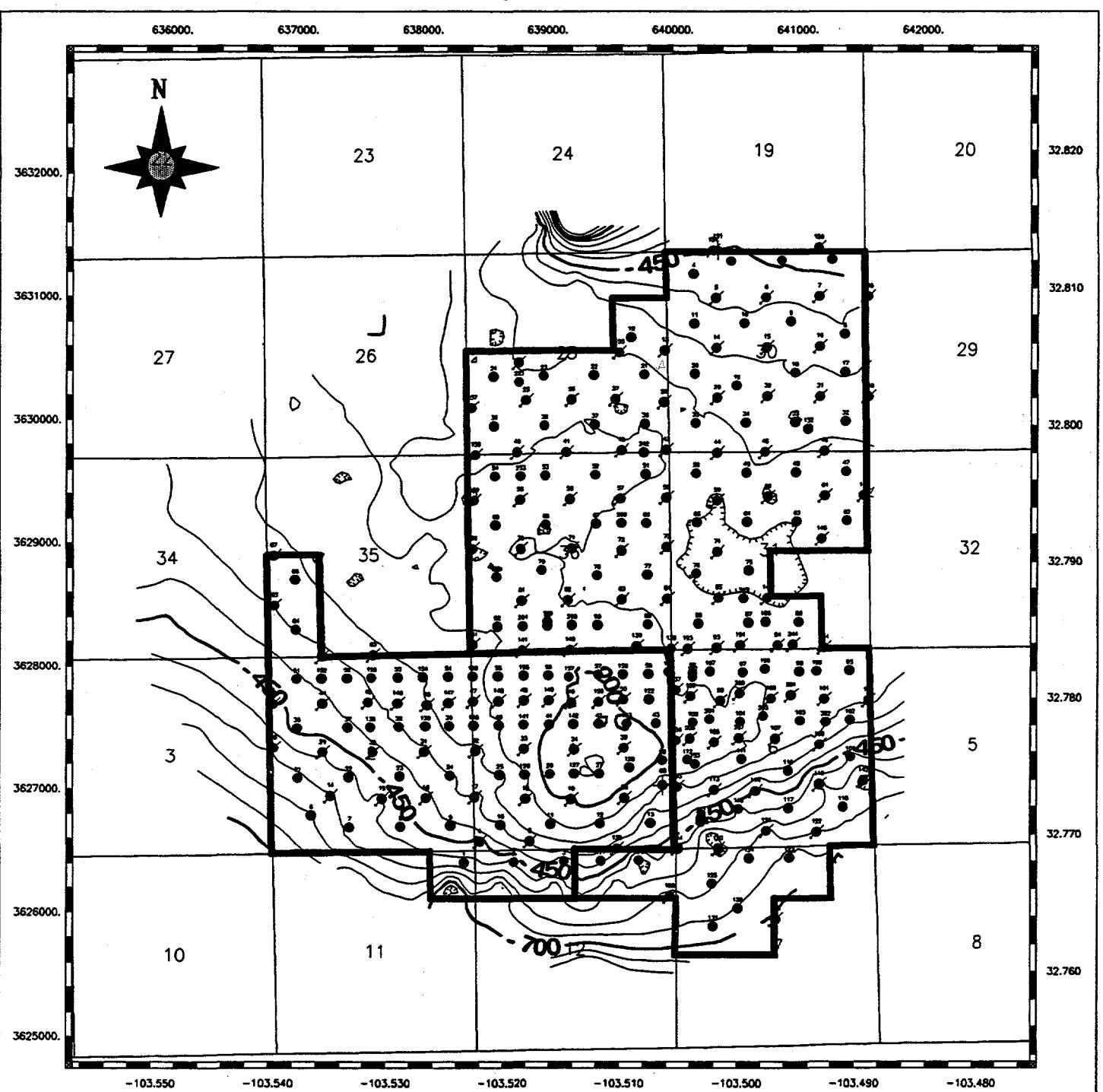
“A”	Waterflood Review: Tabular Data & Miscellaneous Maps
“B”	VIP-COMP Simulation Input/Output Data
“C”	Field Demonstration Historical Performance Data

*** APPENDIX "A" ***

TABLE A-1

WATERFLOOD REVIEW CENTRAL VACUUM UNIT

Avg. 1994 Patient Statistics...										Yr. End 1994									
Injector Centered Pattern	Production Oil	H2O	OCTU	GOR	H2O Infection Rate	Sur. Rate	Eff. In (test)	Eff. In (perf)	Press. NWP/IV	NWP/IV	Peak Oil from Start Yrs.	Initial WF Baktriu from Start Yrs.	WF Baktriu from Start Yrs.	WF Baktriu from Start Yrs.	Pl. of Parts., n	Net Pay, n	Ratio of Pl. to Net to f. period f. net pay.		
1	C1/5	7	34	17	145	47	0.9	1381	1.13	11.0	0.6	4.0	4.0	N					
2	C1/6	6	17	23	76	292	6.2	1314	12.40	11.0	0.1	0.1	0.1	Y					
3	C1/7	3	6	32	65	10	0.2	1078	1.17	3.5	0.1	3.0	N	N	16	1.2			
4	CV1/3	10	250	4	412	260	4.6	1286	1.00	4.0	0.6	0.0	0.0	N	49	30	1.33		
5	CV1/4	12	187	6	124	340	4.3	954	1.89	2.6	0.3	2.5	N	N	47	20	2.35		
6	CV1/5	18	215	8	161	166	2.0	893	0.68	3.0	1.0	3.0	N	N	10	23	0.43		
7	CV1/6	26	91	22	293	226	3.7	134	1.07	3.0	0.6	4.5	N	N	20	12	1.87		
8	CV1/8	22	744	3	272	757	11.9	8.1	864	0.98	4.3	1.0	4.5	N	N	22	12	1.83	
9	CV1/8	22	677	3	626	744	9.5	6.9	807	1.06	3.5	0.1	4.0	N	N	22	12	1.83	
10	CV1/7	17	651	3	683	1209	11.6	4.3	1183	2.12	3.0	1.0	3.0	N	N	14	23	0.43	
11	CV1/8	16	658	3	274	1112	14.1	3.6	1092	2.00	2.5	0.1	3.0	N	N	21	5	4.00	
12	CV1/9	24	624	4	116	603	9.2	2.8	1173	1.10	2.5	0.1	0.5	N	N	21	32	0.66	
13	CV1/9	29	484	6	179	925	14.7	2.0	1058	1.79	2.5	0.6	0.5	N	N	58	19	3.63	
14	CV1/1	33	236	12	495	646	5.6	1.8	1313	1.99	5.5	1.2	1.3	Y	N	30	49	0.75	
15	CV1/0	37	1207	3	273	1330	15.7	10.0	822	1.06	4.6	0.1	6.5	N	N	17	32	0.53	
16	CV1/1	34	1001	3	174	1010	12.5	8.0	1025	1.97	3.5	0.1	4.4	N	N	4	20	0.25	
17	CV1/2	27	853	3	601	833	8.7	6.7	842	0.94	2.7	0.1	4.0	N	N	21	5	4.20	
18	CV1/3	29	880	3	499	746	8.5	5.1	765	0.82	3.5	0.1	4.4	N	N	21	5	4.20	
19	CV1/4	33	776	4	197	325	3.2	4.5	839	0.40	3.0	0.1	3.1	N	N	14	40	0.35	
20	CV1/5	32	609	5	391	644	7.0	4.6	1167	1.00	3.0	0.1	1.1	N	N	22	52	0.42	
21	CV1/6	26	840	4	1074	2165	24.2	6.3	838	3.81	4.0	0.1	1.8	N	N	22	88	0.25	
22	CV1/5	59	1385	4	371	1939	14.9	8.5	639	1.35	4.2	0.1	4.5	N	N	42	70	0.55	
23	CV1/6	43	1120	4	380	618	5.8	9.4	938	0.53	3.0	0.1	3.9	N	N	21	5	4.00	
24	CV1/7	44	129	3	633	1827	16.4	8.8	951	1.41	2.0	0.6	3.5	N	N	21	5	4.20	
25	CV1/8	42	1036	4	433	1317	12.8	8.0	707	1.22	2.2	0.7	3.5	N	N	42	44	0.35	
26	CV1/9	40	1184	3	331	1569	11.6	9.8	1131	1.27	2.5	1.0	3.2	N	N	41	139	0.30	
27	CV1/0	43	959	4	459	746	7.6	8.0	1057	0.76	3.5	1.0	3.2	N	N	25	29	0.89	
28	CV1/1	43	911	4	675	792	5.7	7.0	892	0.82	3.5	0.1	1.5	N	N	42	140	0.30	
29	CV1/0	75	1521	5	450	1953	13.3	11.0	695	1.21	6.5	1.0	6.0	N	N	57	200	0.16	
30	CV1/1	74	1397	5	490	2145	16.3	9.6	745	1.45	3.8	0.1	6.0	N	N	23	59	0.41	
31	CV1/2	71	1581	4	454	2220	20.0	10.6	861	1.33	4.8	0.1	6.6	N	N	22	72	0.31	
32	CV1/3	60	1205	5	476	1987	16.2	10.7	875	1.64	4.0	1.0	3.3	N	N	27	100	0.27	
33	CV1/4	63	1188	4	318	948	10.8	9.8	860	0.76	6.0	2.0	4.0	N	N	45	32	1.41	
34	CV1/1	61	149	1831	7	335	1513	8.3	8.6	810	0.72	4.2	0.2	6.0	N	N	57	200	0.16
35	CV1/2	124	1731	7	348	678	3.2	7.5	695	0.36	3.6	0.1	6.0	N	N	41	200	0.16	
36	CV1/3	81	1165	5	426	1059	6.4	7.2	620	0.85	3.5	0.6	6.1	N	N	86	21	0.41	
37	CV1/4	74	889	7	389	911	6.0	6.7	913	0.85	3.8	0.1	6.1	N	N	31	163	0.18	
38	CV1/5	77	1228	6	930	619	4.7	6.6	702	0.47	3.3	0.1	4.8	N	N	32	139	0.24	
39	CV1/4	77	1166	11	466	1494	6.2	6.0	785	0.92	6.0	0.1	6.0	N	N	23	96	0.24	
40	CV1/0	103	1239	8	395	1344	7.3	5.5	745	0.99	6.0	0.1	6.5	N	N	47	52	0.90	
41	CV1/39	82	1068	7	455	1457	7.8	6.4	744	1.26	4.0	0.1	6.0	N	N	22	161	0.17	
42	CV1/2	79	695	10	411	857	6.2	6.3	695	1.43	3.3	0.1	6.0	N	N	22	141	0.14	
43	CV1/3	74	702	633	11	489	1608	6.3	6.4	983	1.74	3.6	0.1	6.0	N	N	160	26	0.28
44	CV1/4	70	385	18	555	775	4.1	3.4	1050	1.74	3.5	0.1	6.0	N	N	62	21	0.21	
45	CV1/37	98	612	24	462	292	2.6	1.7	933	0.35	3.2	1.0	6.5	N	N	61	45	0.22	
46	CV1/9	99	416	19	241	636	3.4	3.4	1021	1.31	3.5	0.1	6.5	N	N	38	181	0.23	
47	CV1/00	99	208	32	344	62	3.6	1213	3.50	2.2	0.1	10.0	N	N	58	248	0.23		
48	CV1/1	99	116	23	426	440	3.0	2.5	1222	3.25	12.5	0.3	16.0	N	N	31	221	0.14	
49	CV1/38	134	197	41	222	682	6.4	3.3	874	1.94	7.6	0.6	11.0	N	N	35	50	0.70	
50	CV1/06	114	197	37	304	727	4.4	3.3	863	2.22	8.0	0.1	6.2	N	N	66	146	0.47	
51	CV1/07	95	62	60	365	248	1.7	2.6	1260	1.45	6.5	1.0	16.0	N	N	62	20	0.21	
52	CV1/08	60	18	79	644	198	2.7	1.6	1308	2.32	12.0	4.0	16.0	N	N	50	17	0.14	
53	CV1/35	102	178	37	328	614	6.2	3.6	1213	3.50	14.7	0.1	30	N	N	62	33	1.90	
54	CV1/13	113	108	62	322	58	0.8	1.68	125	1.20	0.1	13.0	N	N	35	50	0.70		
55	CV1/14	69	38	62	411	276	4.3	3.3	1316	2.65	11.8	0.6	13.0	N	N	66	146	0.47	
56	CV1/15	11	8	68	124	65	2.5	2.6	976	3.12	0.1	0.1	15.0	N	N	12	5	0.30	
57	CV1/16	67	104	39	422	247	6.8	7.3	793	1.38	15.0	0.1	30	N	N	17	5	1.44	
58	CV1/13	41	300	12	414	42	0.8	1.06	1106	1.12	13.6	0.1	10.5	N	N	14	44	0.32	
59	CV1/20	62	33	61	321	609	3.0	2.5	953	4.88	13.0	0.1	14.0	N	N	22	5	4.40	
60	CV1/21	18	11	61	322	45	3.6	1126	4.42	12.0	0.1	13.0	N	N	22	5	4.40		



TEXACO EXPLORATION & PRODUCTION, INC.

GRAYBURG DOLOMITE STRUCTURE, FT. SUBSEA

FIGURE A-1

C.I. = 50

Scale 1:46263.88

Taylor, Sharon

22, 1996

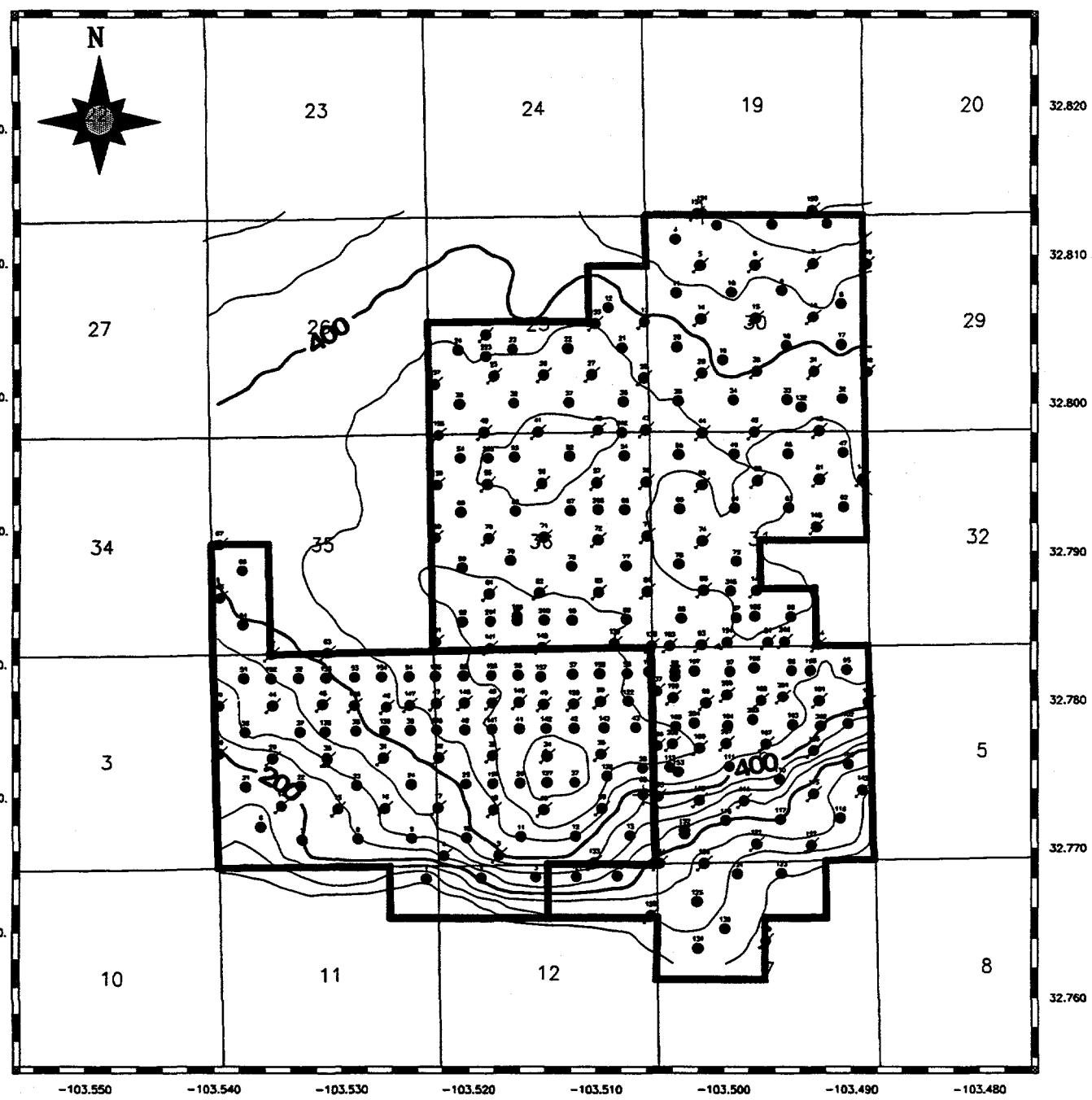
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0.2 0. 0.20.40.60.8 1. kilometers





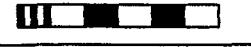
TEXACO EXPLORATION & PRODUCTION, INC.		
GROSS PAY, FT. ABOVE -735 SUBSEA		
FIGURE A-2		
CL = 50	Scale 1:45433.59	
Taylor, Sharon	7/22/96	

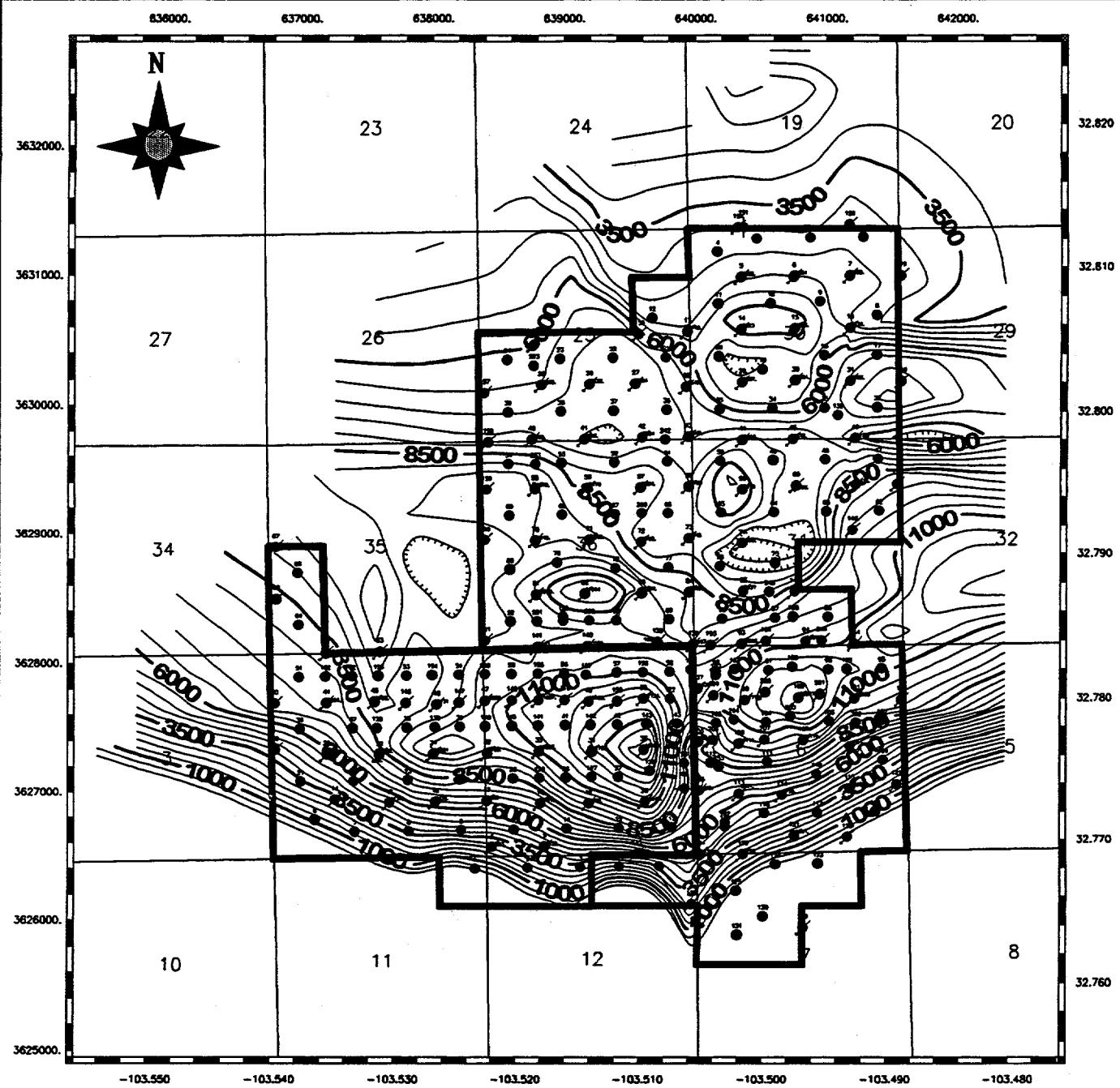
Scale 1:45433.59

0.2 0. 0.2 0.4 0.6 0.8 1. miles



0.2 0. 0.20.40.60.8 1. kilometers





TEXACO EXPLORATION & PRODUCTION, INC.

TOTAL PORE VOLUME, MRVB

FIGURE A-3

C.I. = 500

Scale 1:46993.29

Taylor, Sharon

7/18/96

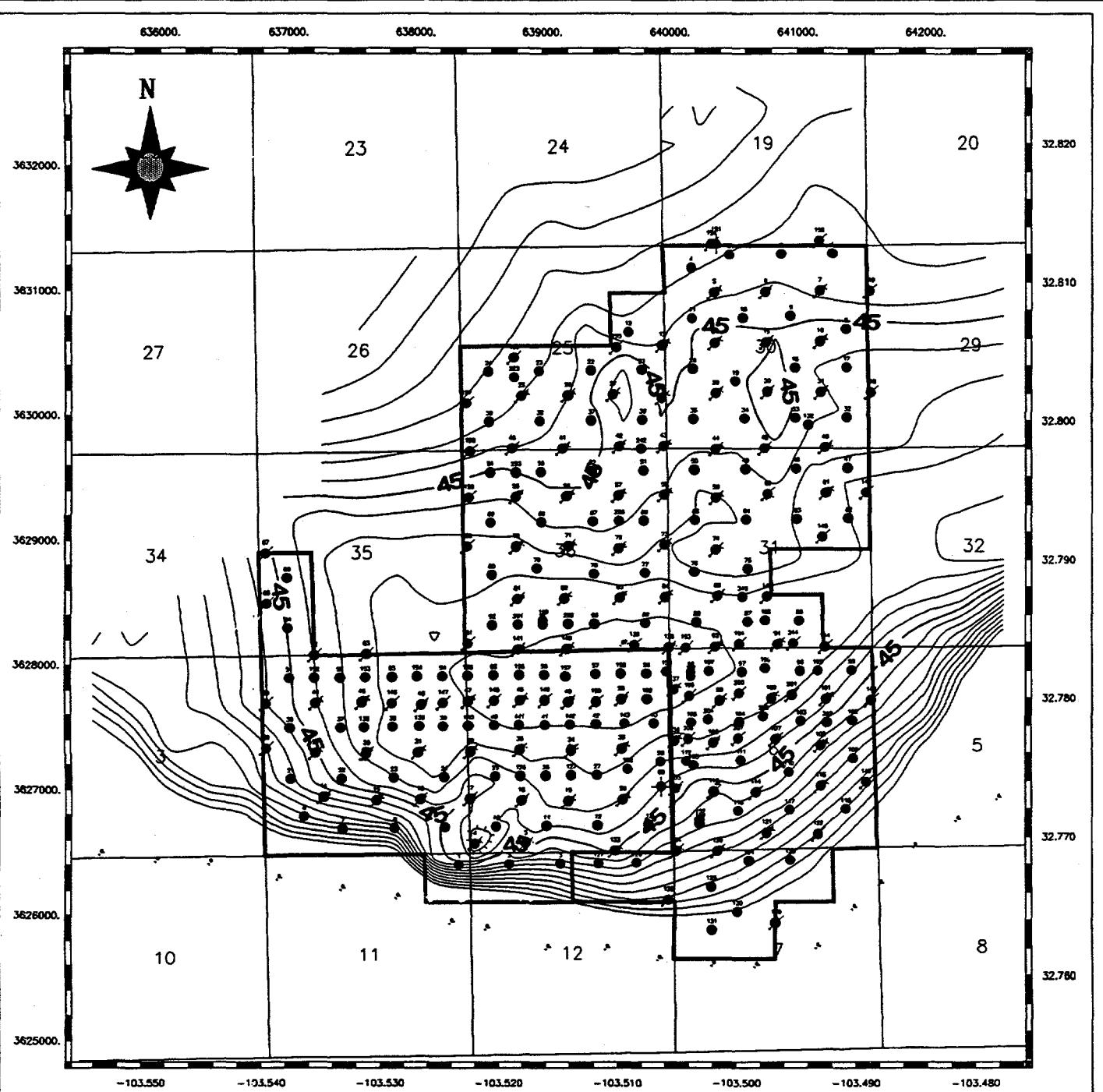
Scale 1:46993.29

0.2 0. 0.2 0.4 0.6 0.8 1. miles



0.2 0. 0.20.40.60.8 1. kilometers





TEXACO EXPLORATION & PRODUCTION, INC.

AVG. SWI OF GROSS PAY, %

FIGURE A-4

C1 = 5

Scale 1:46642.35

Taylor, Sharon

7/18/96

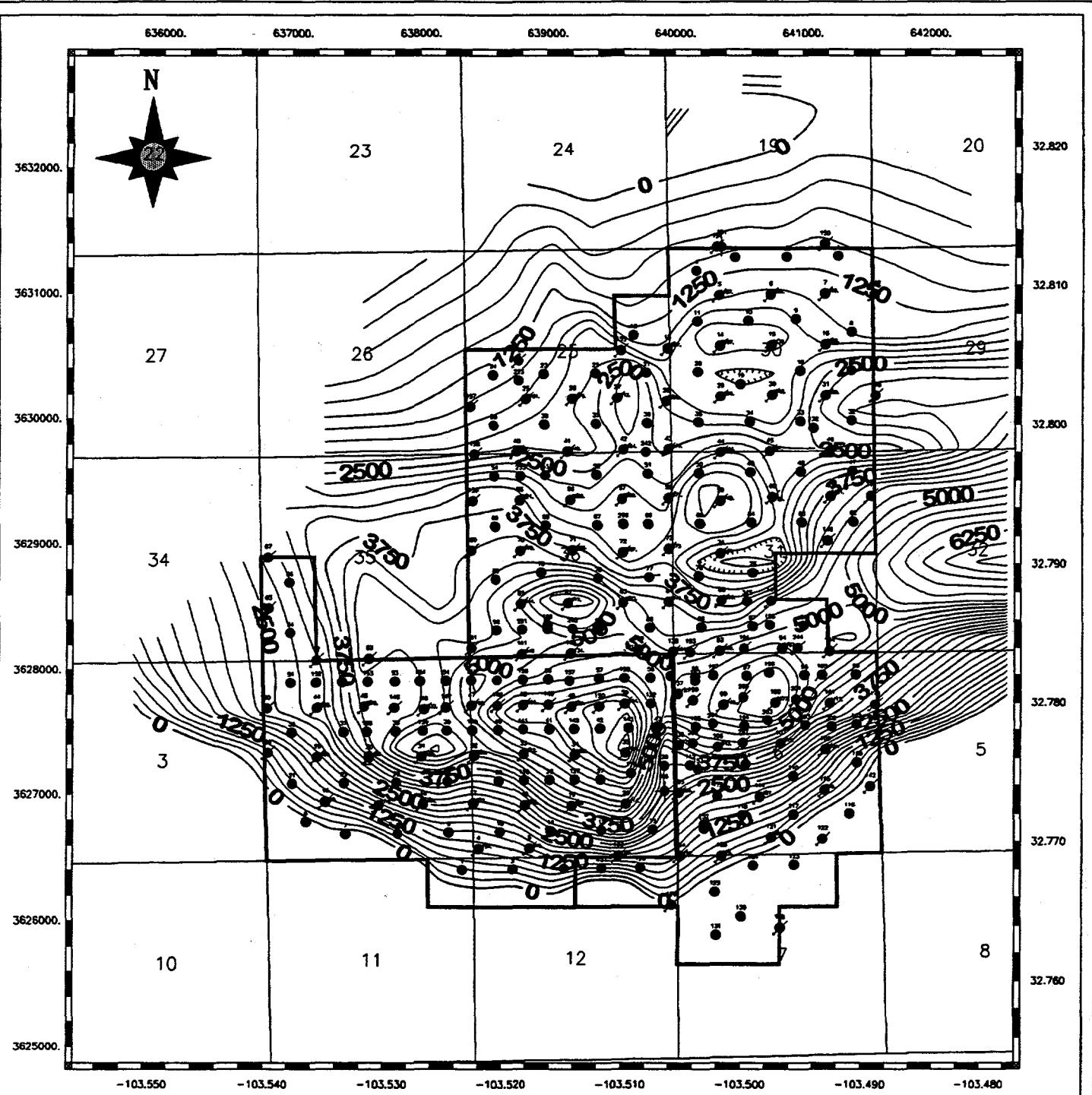
Scale 1:46642.35

0.2 0. 0.2 0.4 0.6 0.8 1. miles



0.2 0.0.20.40.60.8 1. kilometers





TEXACO EXPLORATION & PRODUCTION, INC.

OOIP, MSTB

FIGURE A-5

C.I. = 250

Scale 1:45387.43

Taylor, Sharon

7/18/96

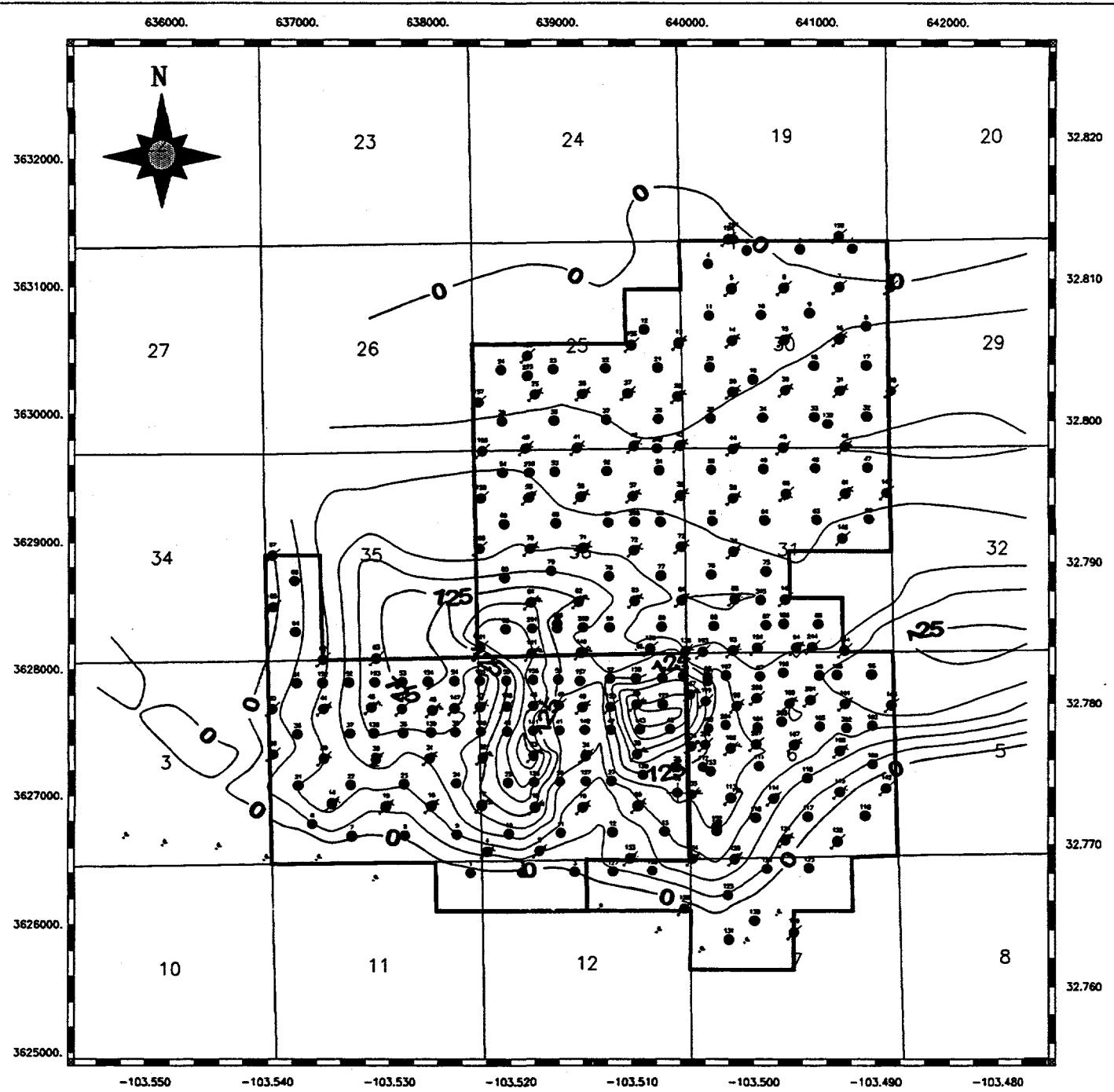
Scale 1:45387.43

0.2 0. 0.2 0.4 0.6 0.8 1. miles



0.2 0. 0.20.40.60.8 1. kilometers





TEXACO EXPLORATION & PRODUCTION, INC.

1994 AVG. OIL RATE, BOPD

FIGURE A-6

CL = 25

Scale 1:46037.37

Taylor, Sharon

7/18/96

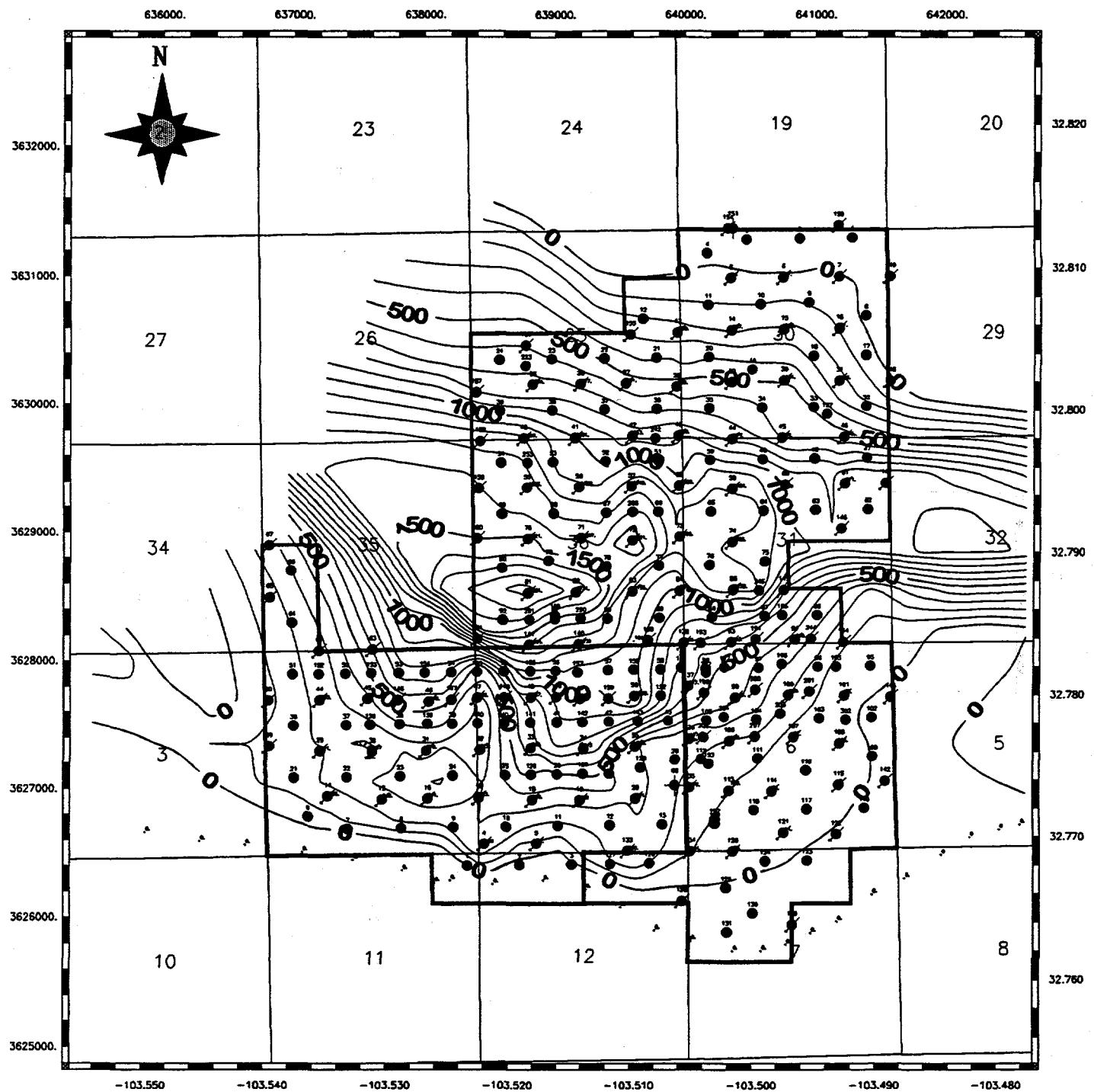
Scale 1:46037.37

0.2 0. 0.2 0.4 0.6 0.8 1. miles



0.2 0. 0.2 0.4 0.6 0.8 1. kilometers





TEXACO EXPLORATION & PRODUCTION, INC.

1994 AVG. H2O RATE, BWPD

FIGURE A-7

C.I. = 100

Scale 1:44483.71

Taylor, Sharon

7/18/96

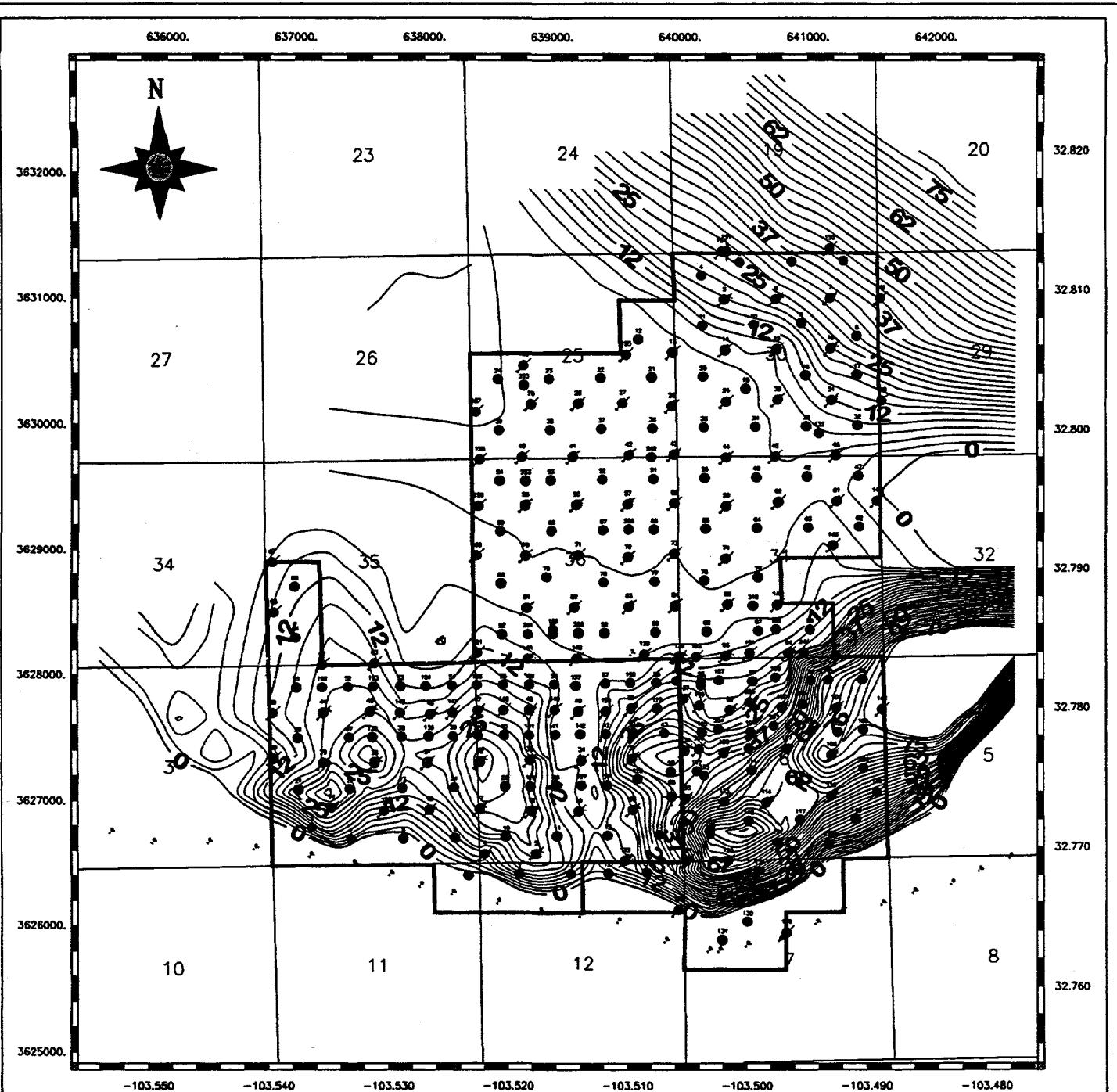
Scale 1:44483.71

0.2 0. 0.2 0.4 0.6 0.8 1. miles



0.2 0. 0.20.40.60.8 1. kilometers





TEXACO EXPLORATION & PRODUCTION, INC.

1994 AVG. OIL CUT, %

FIGURE A-8

$C_1 = 2.5$

Scale 1:46601.89

Taylor, Sharon

7/18/96

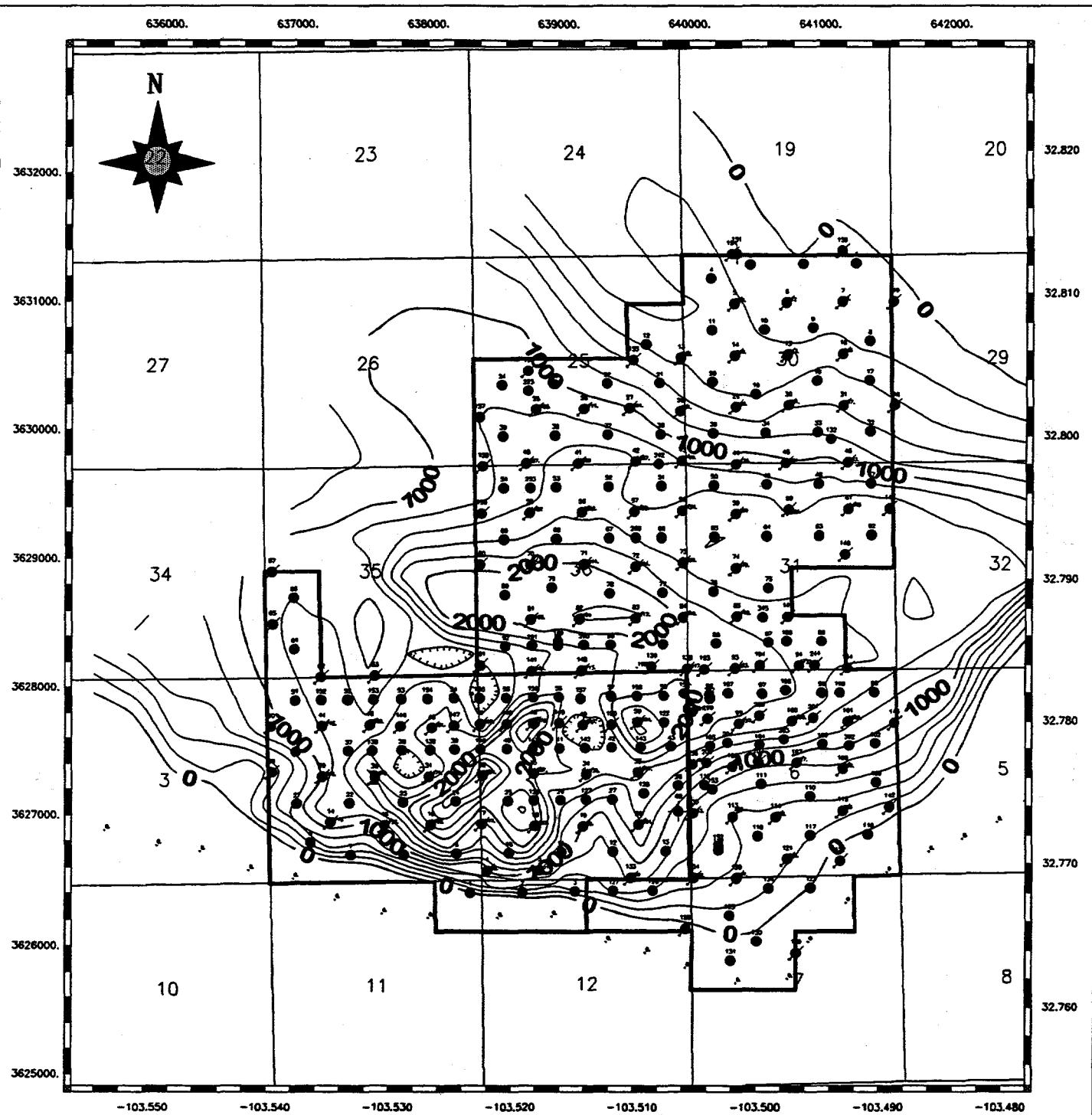
Scale 1:46601.89

0.2 0. 0.2 0.4 0.6 0.8 1. miles



0.2 0. 0.20.40.60.8 1. kilometers





TEXACO EXPLORATION & PRODUCTION, INC.

CUM. OIL RECOVERY, MSTB (01/01/95)

FIGURE A-9

C.J. = 200

Scale 1:44597.59

Taylor, Sharon

7/18/96

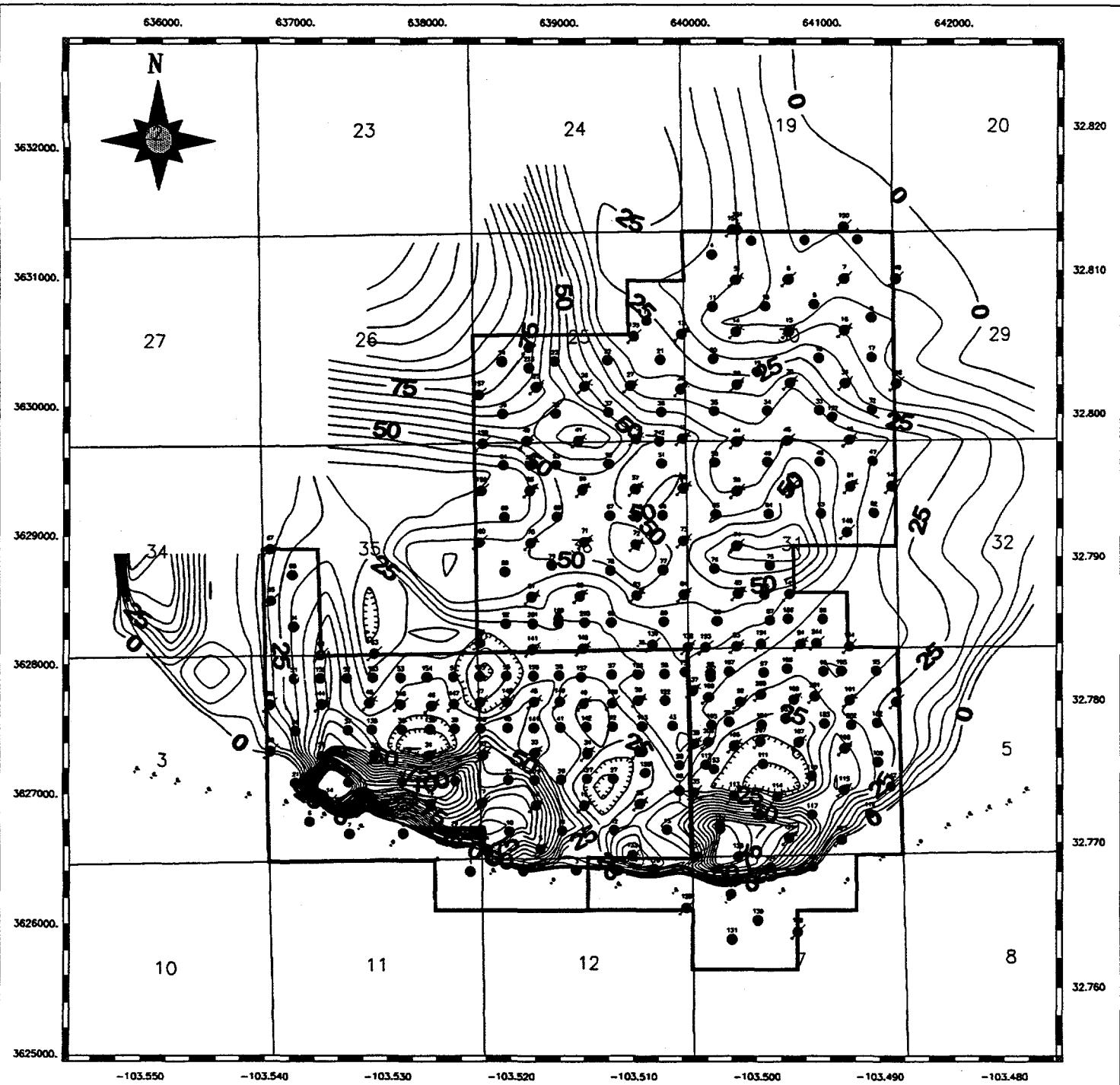
Scale 1:44597.59

0.2 0. 0.2 0.4 0.6 0.8 1. miles



0.2 0. 0.20.40.60.8 1. kilometers





TEXACO EXPLORATION & PRODUCTION, INC.

CUMMULATIVE OIL RECOVERY,
%OOPI (01/01/95)
FIGURE A-10

CL = 5

Scale 1:44008.08

Taylor, Sharon

7/18/96

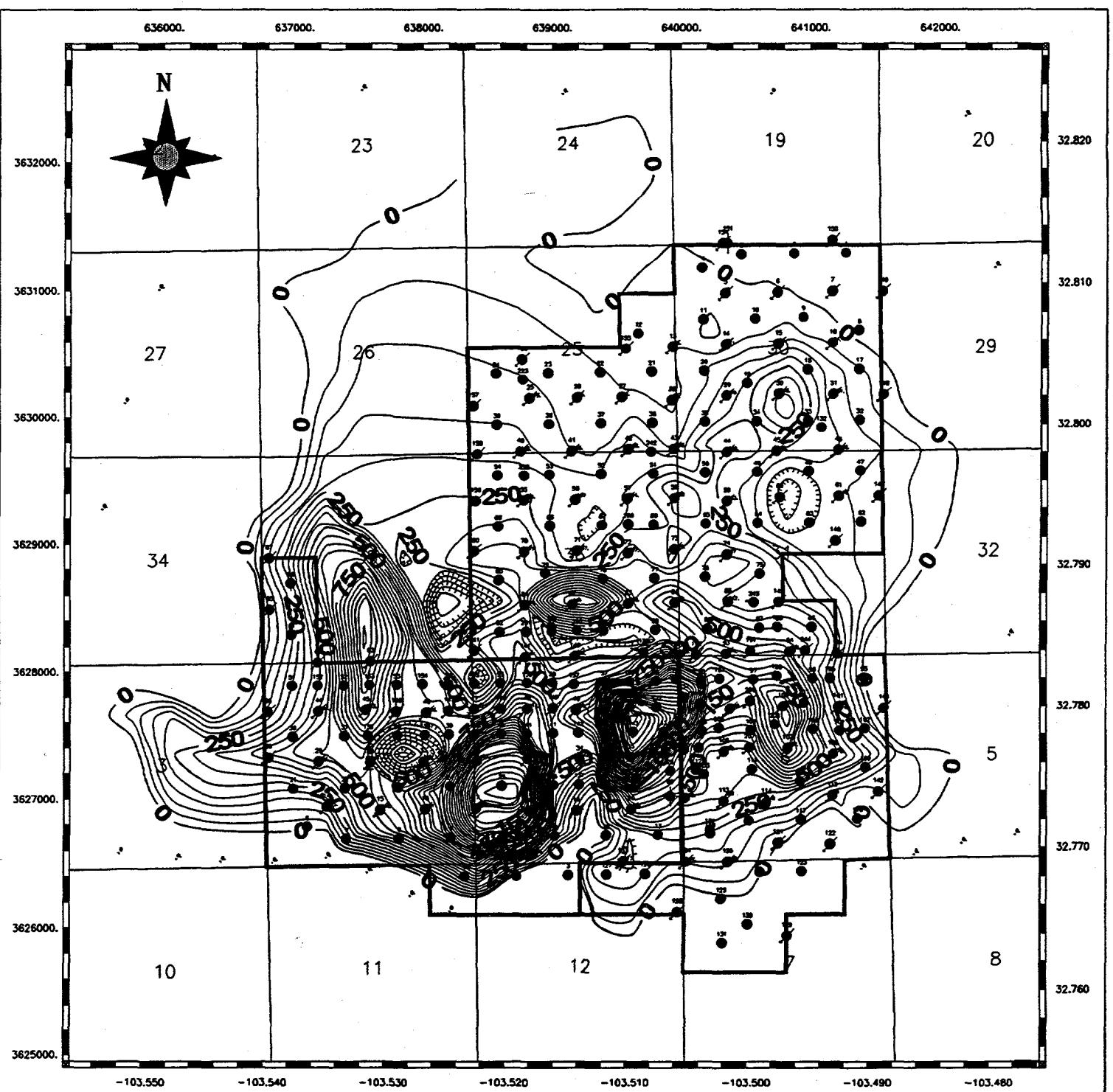
Scale 1:44008.08

0.2 0. 0.2 0.4 0.6 0.8 1. miles



0.2 0. 0.20.40.60.8 1. kilometers





TEXACO EXPLORATION & PRODUCTION, INC.

RSVS. (Q vs t)
Rsvs. MSTB (01/01/95)
FIGURE A-11

C.L. = 50

Scale 1:43403.54

Taylor, Sharon

7/18/96

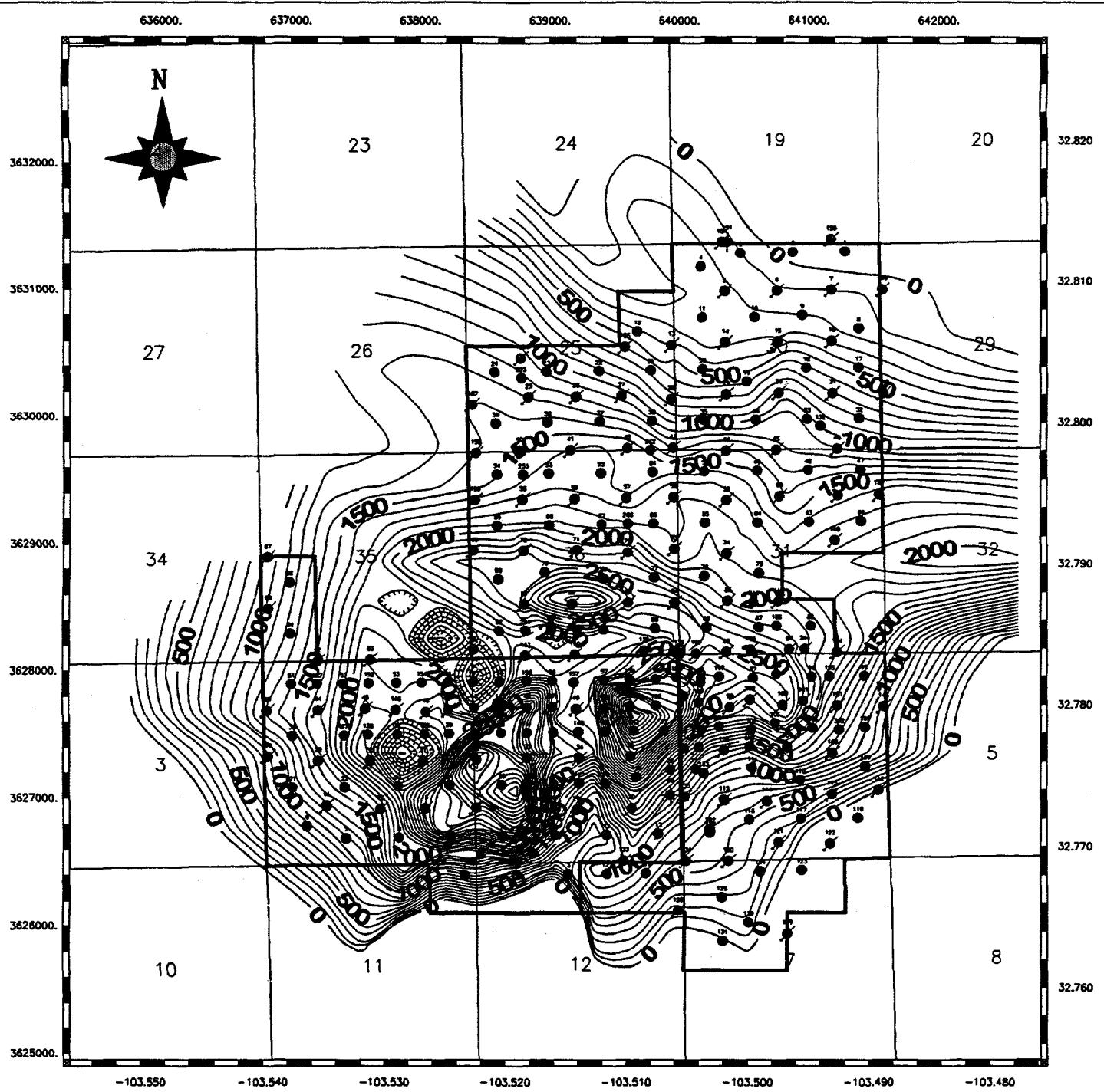
Scale 1:43403.54

0.2 0. 0.2 0.4 0.6 0.8 1. miles



0.2 0. 0.20.40.60.8 1. kilometers





TEXACO EXPLORATION & PRODUCTION, INC.

RSVS. FORECAST (Q vs t)

Np, MSTB

FIGURE A-12

Scale 1:45107.2

0.2 0. 0.2 0.4 0.6 0.8 1. miles



0.2 0. 0.20.40.60.8 1. kilometers

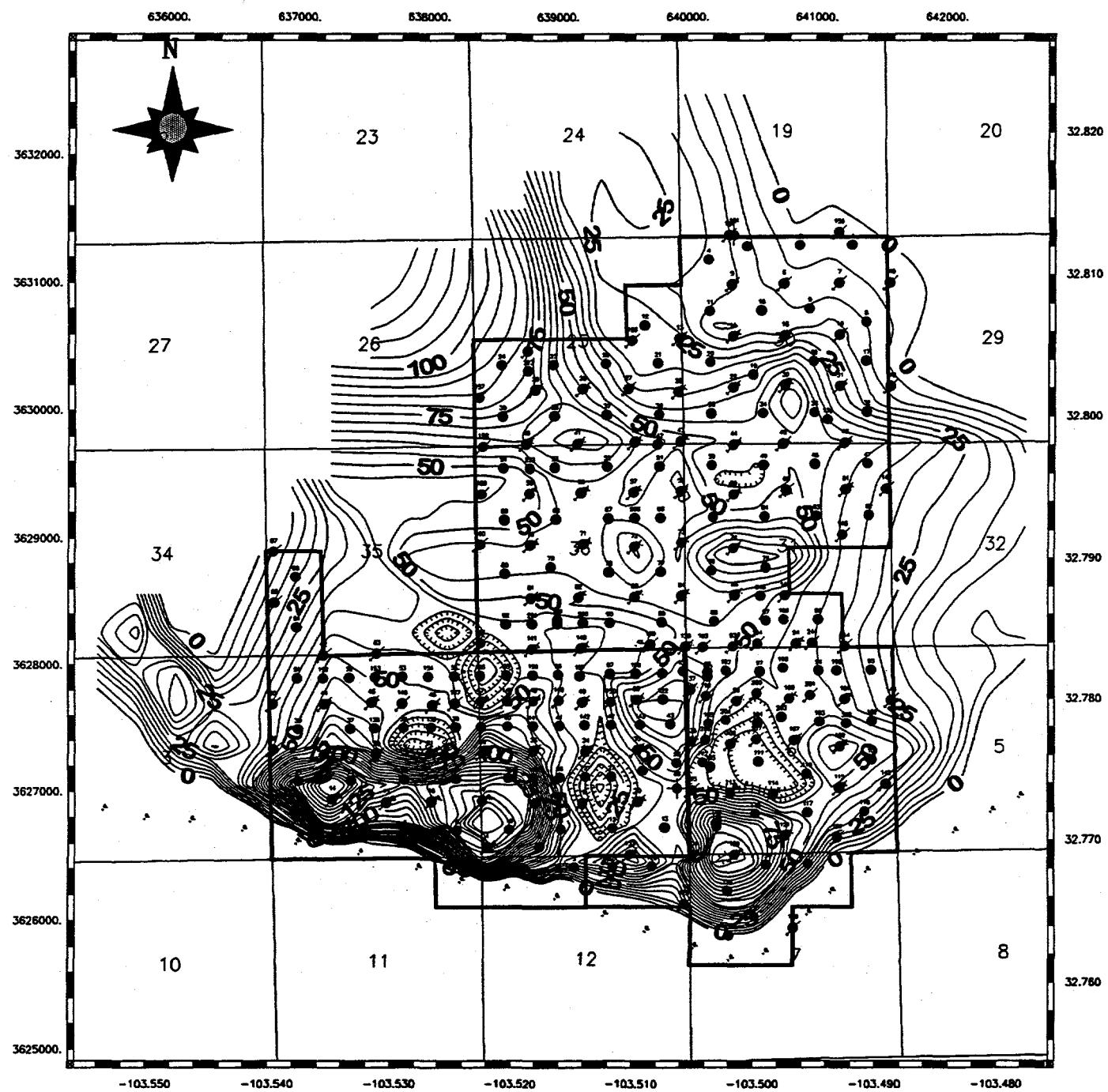


CJ = 100

Scale 1:45107.2

7/18/96

Taylor, Sharon



TEXACO EXPLORATION & PRODUCTION, INC.

RSVS. FORECAST (Q vs t)

Np, % OOIP

FIGURE A-13

C.I. = 5

Scale 1:46363.22

Taylor, Sharon

7/18/96

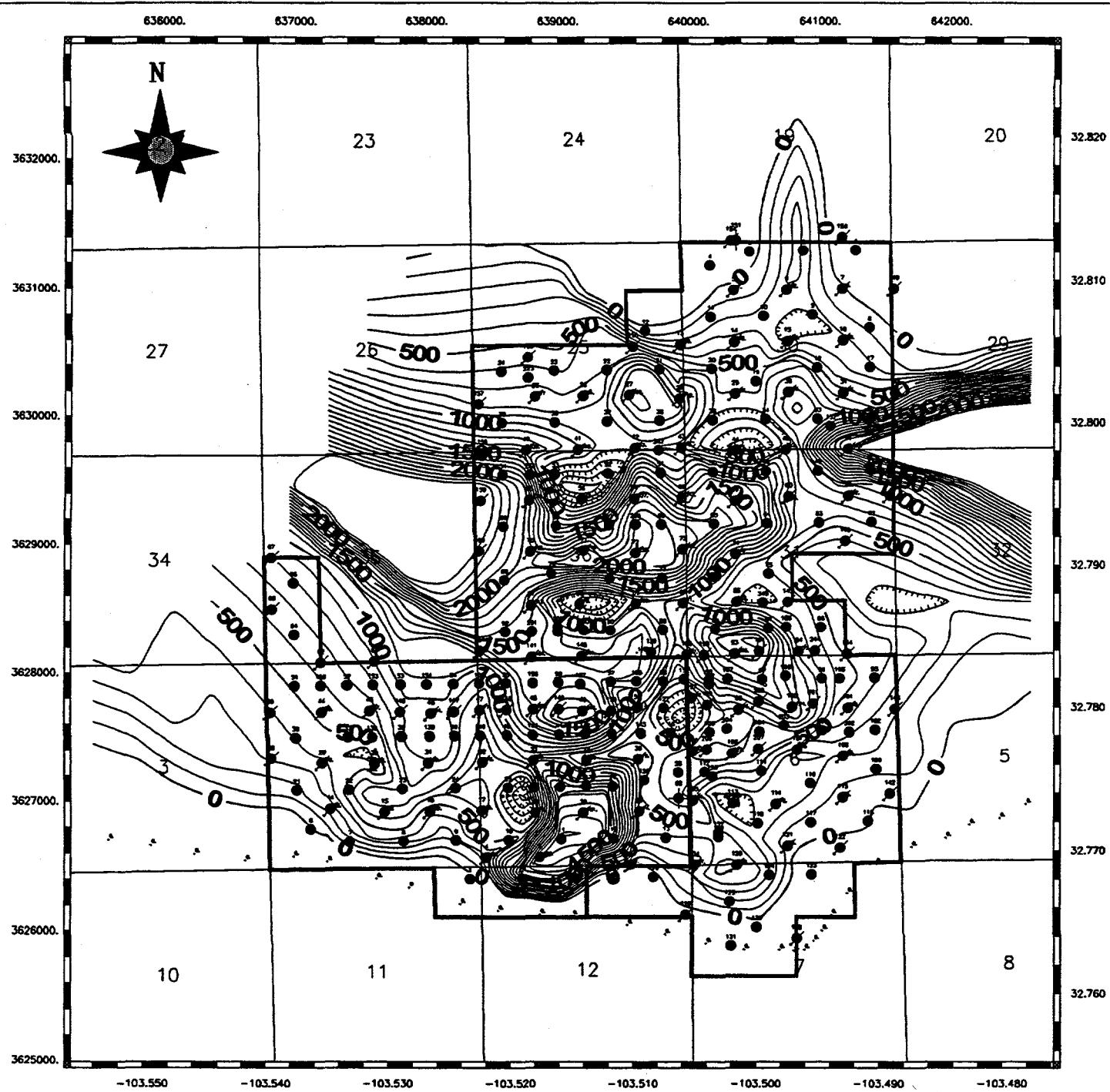
Scale 1:46363.22

0.2 0. 0.2 0.4 0.6 0.8 1. miles



0.2 0. 0.2 0.4 0.6 0.8 1. kilometers





TEXACO EXPLORATION & PRODUCTION, INC.

1994 AVG. H₂O INJ. RATE (BWPD)

FIGURE A-14

C.I. = 100

Scale 1:44766.38

Taylor, Sharon

7/18/96

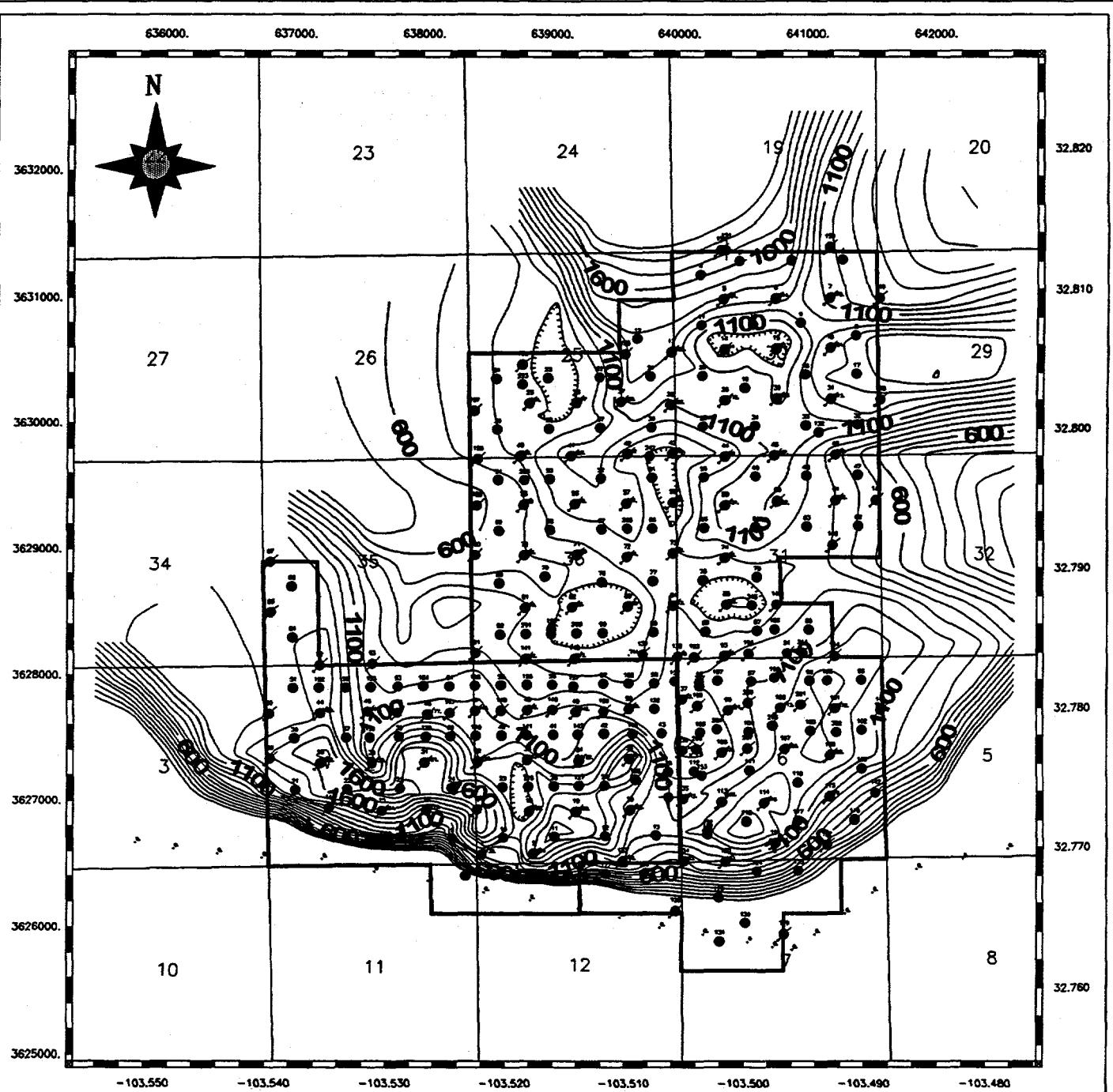
Scale 1:44766.38

0.2 0. 0.2 0.4 0.6 0.8 1. miles



0.2 0. 0.20.40.60.8 1. kilometers





TEXACO EXPLORATION & PRODUCTION, INC.

1994 AVG. SURF. H2O INJ. PRESS., PSIG

FIGURE A-15

C.I. = 100

Scale 1:46397.56

Taylor, Sharon

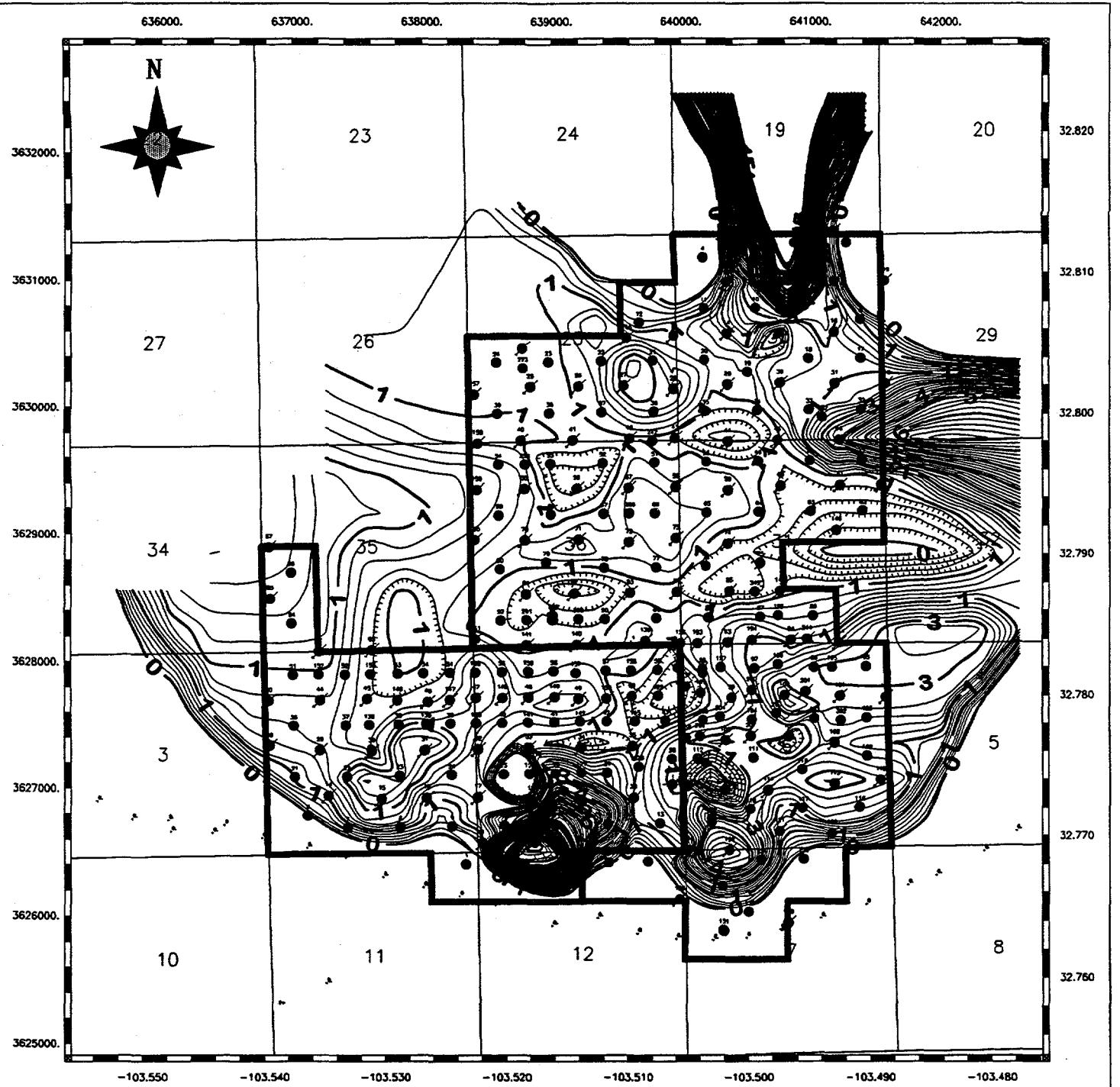
7/18/96

Scale 1:46897.56

0.2 0. 0.2 0.4 0.6 0.8 1. miles

1 2 3 4

0.2 0. 0.20.40.60.8 1. kilometers



TEXACO EXPLORATION & PRODUCTION, INC.

1994 AVG. INJECTION WITHDRAWAL RATE

FIGURE A-16

CL = 0.2

Scale 1:44888.29

Taylor, Sharon

7/22/96

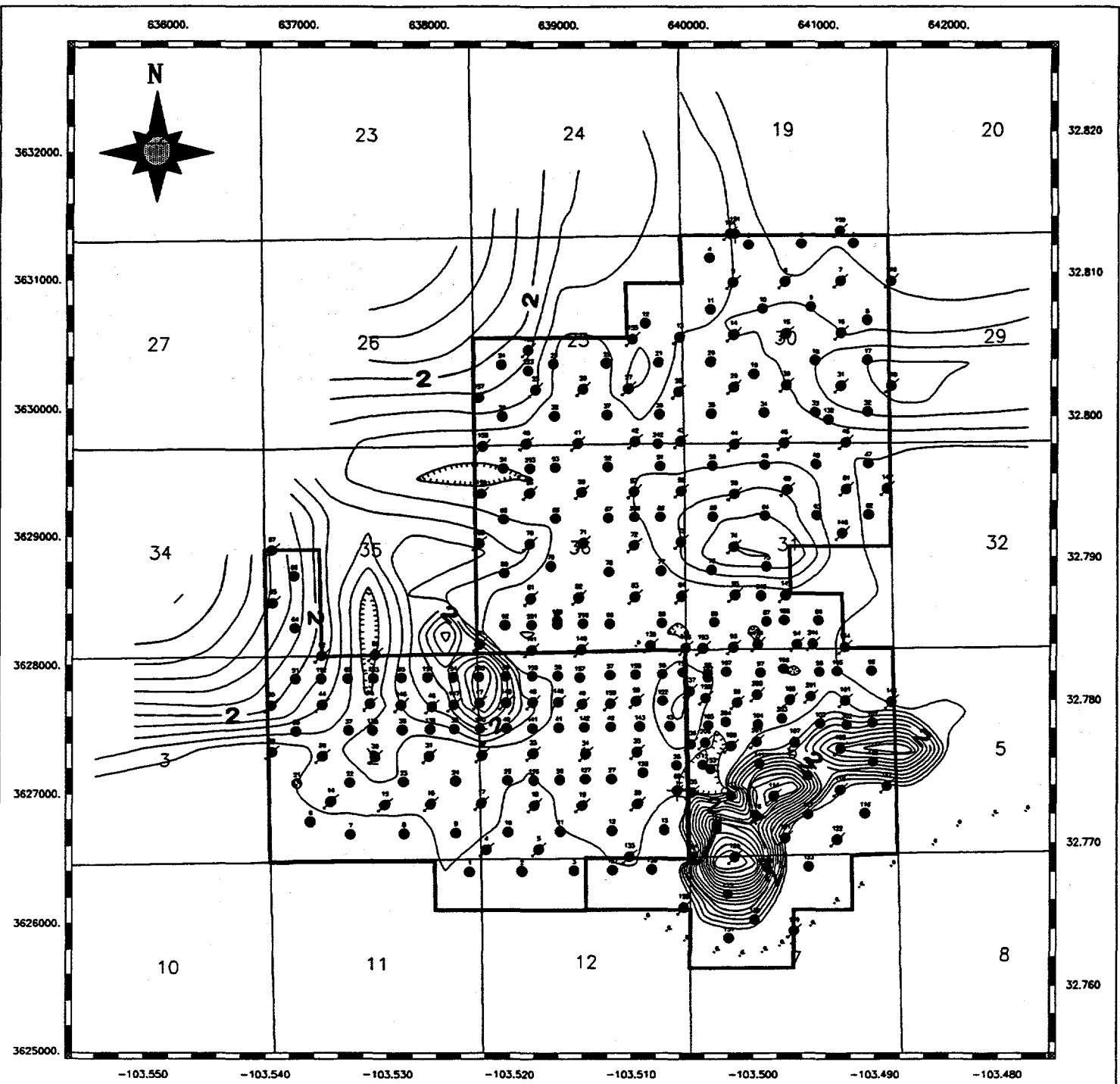
Scale 1:44888.29

0.2 0. 0.2 0.4 0.6 0.8 1. miles



0.2 0. 0.20.40.60.8 1. kilometers





TEXACO EXPLORATION & PRODUCTION, INC.

INITIAL WF BREAKTHROUGH, YRS FROM START

FIGURE A-17

CI = 0.5

Scale 1:44230.35

Taylor, Sharon

7/18/96

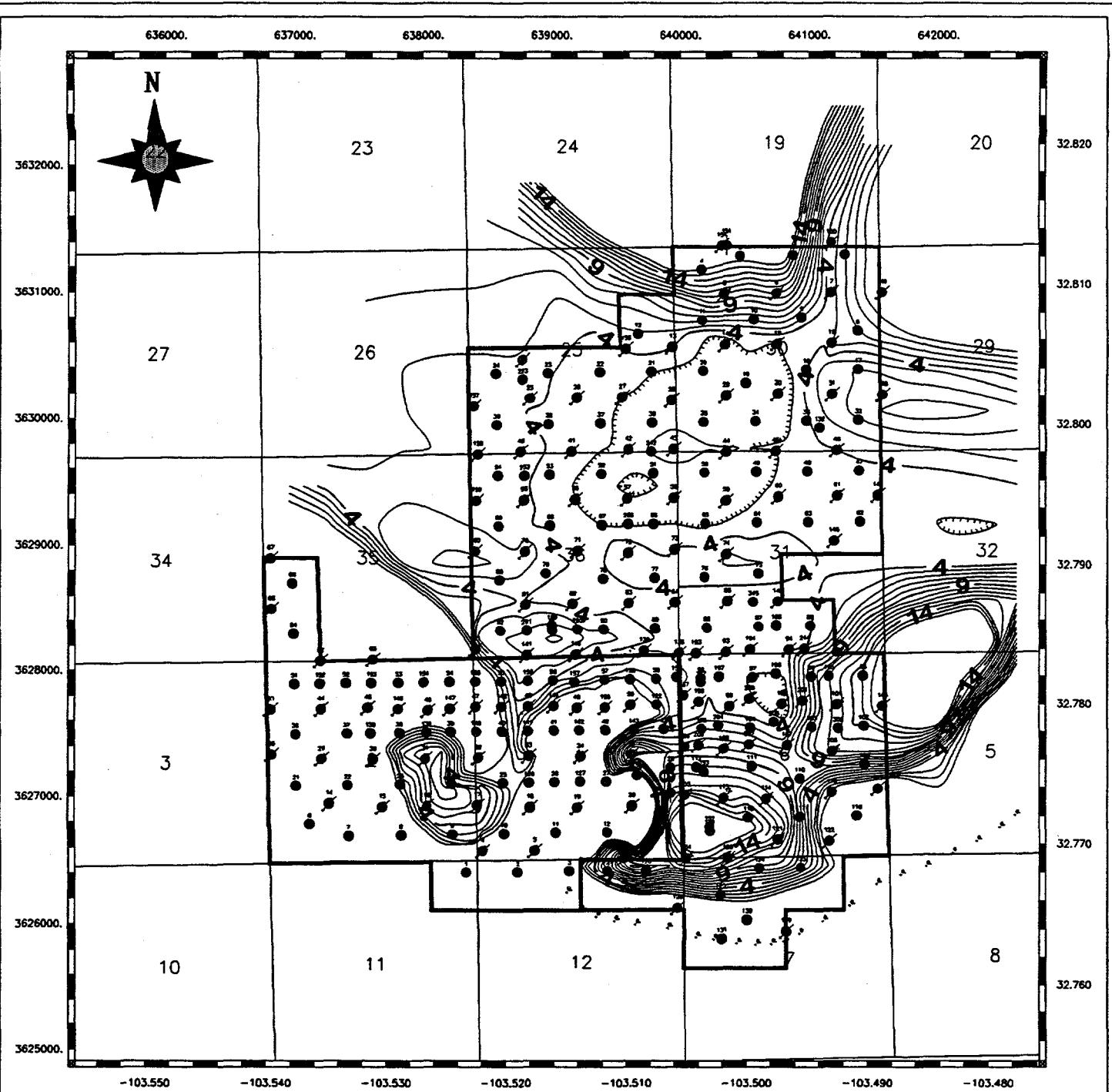
Scale 1:44230.35

0.2 0. 0.2 0.4 0.6 0.8 1. miles



0.2 0. 0.20.40.60.8 1. kilometers





TEXACO EXPLORATION & PRODUCTION, INC.

WF PEAK OIL RESPONSE, YRS. FROM START

FIGURE A-18

$$C_1 = 1$$

Scale 1:45628.04

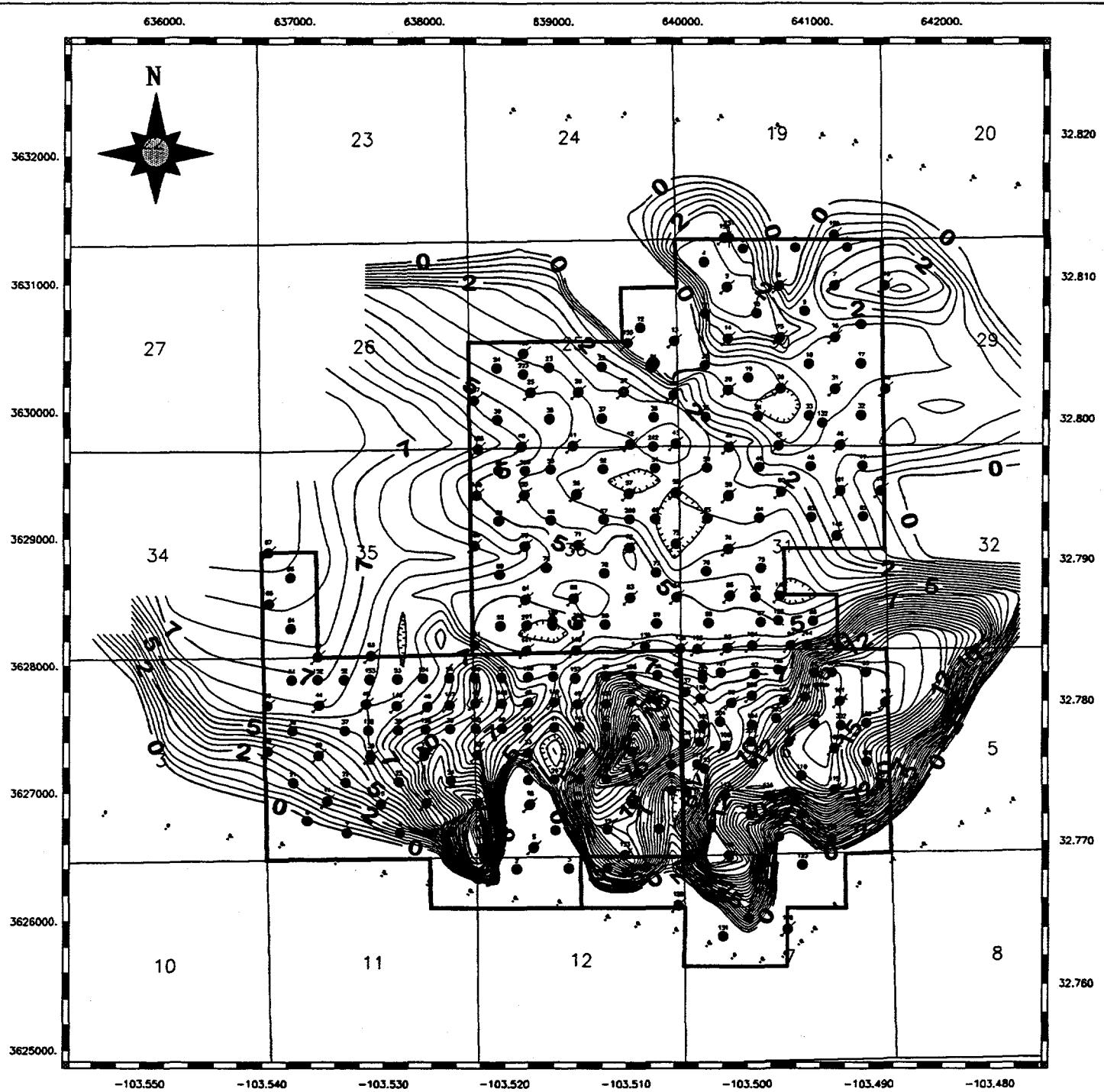
Taylor, Sharon

7/18/96

Scale 1:45628.04

0.2 0. 0.2 0.4 0.6 0.8 1. miles

0.2 0.40.60.8 1. kilometers



TEXACO EXPLORATION & PRODUCTION, INC.

50% H₂O BREAKTHROUGH, YRS. FROM START

FIGURE A-19

CL = 0.5

Scale 1:44885.79

Taylor, Sharon

7/18/96

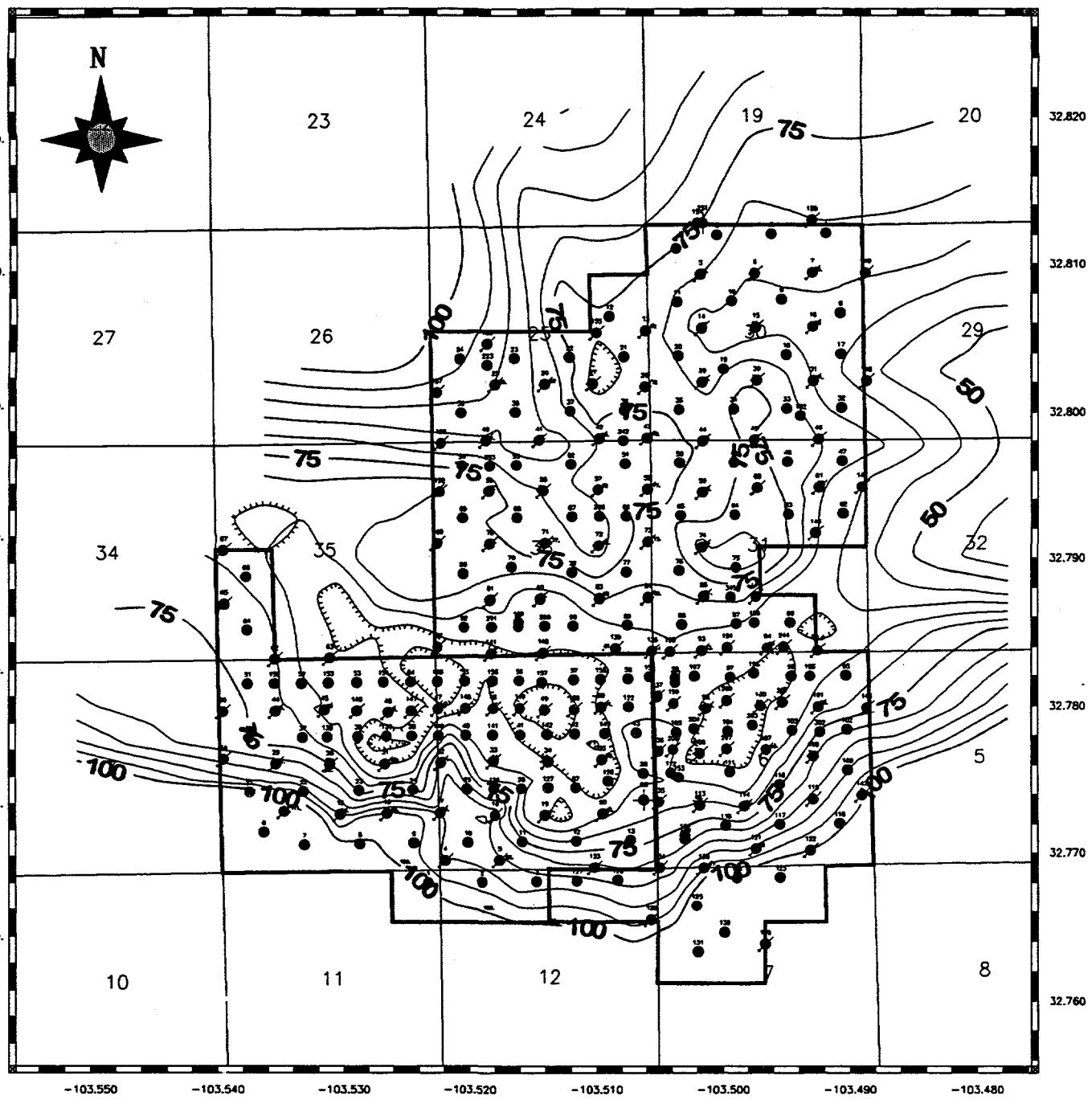
Scale 1:44885.79

0.2 0. 0.2 0.4 0.6 0.8 1. miles



0.2 0. 0.20.40.60.8 1. kilometers





TEXACO EXPLORATION & PRODUCTION, INC.

GROSS PAY AVG. SW, % (01/01/95)

FIGURE A-20

C.I. = 5

Scale 1:45261.5

Taylor, Sharon

7/18/96

Scale 1:45261.5

0.2 0. 0.2 0.4 0.6 0.8 1. miles

0.2 0. 0.20.40.60.8 1. kilometers

*** APPENDIX "B" ***

TABLE B-1

c Core Input File for VIP-COMP without Array Data (142 pgs.)

c
INIT
TITLE1
CENTRAL VACUUM
TITLE2
SITE SPECIFIC
TITLE3
HUFF N PUFF RUNS
DATE 30 12 1993
PLOT
MAP
GIBBS
PRINT NONE
PRINT INIT ALL
C PRINT COMP ALL
C
C
C STRATAMODEL GRID SYSTEM
C
NX NY NZ NCMP
22 26 12 9
LGR
CARTREF W99
2 2 12 12 1 12
1
1
12*1
ENDREF
CARTREF W93
1 1 1 1 1 12
1
1
12*1
ENDREF
CARTREF W100
12 12 12 12 1 12
1
1
12*1
ENDREF
CARTREF W94
13 13 1 1 1 12
1
1
12*1
ENDREF
RADZREF W97
7 6 1 12
5 1 0.33 RMIN 7
12*1
13*.5
13*.5
ENDREF
ENDLGR
C
C
C
C
C PHYSICAL PROPERTIES CONSTANTS
C
DWB BWI VW CW CR TRES TS PS
1.00 1.000 .75 3.200E-6 3.200E-6 105 60 14.65
C
KROINT
C
HCPVTAB 50
C
C

NONEQ
 C
 C
 TABLES
 C
 C EQUILIBRIUM TABLE
 C
 C
 IEQUIL PINIT DEPTH PCWOC WOC PCGOC GOC PSAT
 1 1620 700 21.0 840 0.0 200 790
 C
 C
 C
 C PVT DATA - EOS PARAMETERS
 C
 C
 C
 EOS ZJRK
 COMPONENTS
 CO2 C1N2 C2 C3 C4 C5C6 HVY1 HVY2 HVY3
 PROPERTIES F PSIA
 COMP MW TC PC ZC ACENTRIC OMEGAA OMEGAB PCHOR >
 NBP GRVL TREF
 CO2 44.01 87.90 1070.90 .2742 .2225 .4019551 .0806553 49.6 >
 -261.0 .3000 60.0
 C1N2 16.49 -120.93 661.30 .2888 .0135 .4244240 .0865580 69.7 >
 -109.3 .8150 60.0
 C2 30.07 90.10 707.80 .2850 .0978 .4274800 .0866400 111.0 >
 -127.5 .3560 60.0
 C3 44.10 206.00 616.30 .2810 .1541 .4274800 .0866400 151.0 >
 -43.7 .5080 60.0
 C4 58.12 302.84 548.70 .2748 .1999 .4274230 .0866250 191.0 >
 29.2 .5820 60.0
 CSC6 78.22 411.70 466.60 .2665 .2680 .4277090 .0864750 248.3 >
 119.3 .6440 60.0
 HVY1 133.10 665.04 381.10 .3299 .4139 .4012600 .0866600 428.2 >
 327.6 .7770 60.0
 HVY2 251.34 920.57 258.50 .2959 .7674 .4012600 .0866600 754.2 >
 595.6 .8521 60.0
 HVY3 466.61 1215.37 177.40 .1498 1.5095 .3283300 .0703300 1528.4 >
 937.1 .9225 60.0
 DJK C1N2
 CO2 .0700000
 C2 .0000000
 C3 .0000000
 HVY1 .0414000
 DJK C2
 CO2 .0700000
 DJK C3
 CO2 .0700000
 C2 .0000000
 DJK C4
 CO2 .0700000
 C2 .0100000
 C3 .0100000
 HVY1 .0000000
 C1N2 .0196000
 DJK C5C6
 CO2 .0700000
 C2 .0100000
 C3 .0100000
 HVY1 .0000000
 C1N2 .0219000
 C4 .0000000
 DJK HVY1
 CO2 .1513587
 C2 .0100000
 C3 .0100000
 DJK HVY2
 CO2 .0726924
 C2 .0100000

C3 .0100000
 HVY1 .0000000
 C1N2 .0520000
 C4 .0000000
 C5C6 .0000000
 DJK HVY3
 CO2 .1097270
 C2 .0100000
 C3 .0100000
 HVY1 .0000000
 C1N2 .0649000
 C4 .0000000
 C5C6 .0000000
 HVY2 .0000000

C
 ENDEOS
 C
 OILMF 1
 0.0203 0.1419 0.0983 0.0980 0.0838 0.0904 0.2721 .1529 .0423
 GASMF 1
 X X X X X X X

C
 C WATER SATURATION TABLE
 C

SWT 1
 SW KRW KROW PCWO
 0.2000 0.0000 1.0000 5.0
 0.3000 0.1000 0.3000
 0.4000 0.2000 0.0800
 0.5000 0.3000 0.0200
 0.6000 0.4000 0.0050
 0.6500 0.4500 0.0020
 0.7000 0.5000 0.0000
 1.0000 1.0000 0.0000 0.0000

C
 C
 C GAS SATURATION TABLE
 C

SGT 1
 C SGTR 0.30
 C With hysteresis
 C

SG	KRG	KROG	PCGO
0.0000	0.0000	1.0000	0.0000
0.0300	0.0000	0.9400	8.0000
0.1000	0.0180	0.72	10.000
0.2000	0.0400	0.339	12.00
0.3000	0.0650	0.1757	14.00
0.4000	0.0850	0.0756	16.000
0.4500	00.1000	0.0509	17.
0.5000	00.1150	0.0265	18.00
0.6000	00.1370	0.0050	20.0000
0.6150	00.1420	0.0000	20.30
0.6500	00.1600	0.0000	21.000
0.7000	00.1800	0.0000	22.0000
0.7500	00.2000	0.0000	120.0000
0.8000	00.2200	0.0000	200.000

C
 C
 C ARRAY DATA
 C

C
 C
 C
 C IN ANOTHER FILE
 C

C
 STOP
 END
 C
 C
 C END OF CORE PART, START OF EXEC

C Exec Input File for VIP-COMP Simulation

C

RUN

DIM NPRFMX NPRFTOT NWMAX

12 336 28

IMPES

RESTART 0 3

IMPGRID

W93 IMPLICIT

W97 IMPLICIT

W99 IMPLICIT

W100 IMPLICIT

W94 IMPLICIT

ENDIMPGRID

START

GIBBS

OUTPUT P SO

SSSUM FIELD TAB TIME DATE QGP QOP QWP QGI QWI CGP COP CWP CGI CWI TPVP

PRINT WELLS REGIONS SSSUM TIME

C -----Timestep Control-----

C SWITCH DTMIN DTMAX DPMAX DSMAX DVMAX DZMAX

DT -1 0.0001 100 300

IMPSTAB .7

C ITNMIN ITNMAX DPLIM DSWLIM DVLM DZLIM

ITNLIM 1 22

TCUT 20 20

TOLR .005 .0005 RELTOL

CBLITZ

C

C -----WELL DATA-----

C

WELL N NAME IW JW GRID

1 CVU195 22 7 ROOT

2 CVU96 17 6 ROOT

3 CVU196 12 6 ROOT

4 CVU97 X X W97

5 CVU197 1 7 ROOT

13 CVU99 1 1 W99

14 CVU200 7 11 ROOT

15 CVU100 1 1 W100

16 CVU201 17 12 ROOT

17 CVU101 22 12 ROOT

6 CVU204 1 16 ROOT

7 CVU104 6 16 ROOT

8 CVU203 11 16 ROOT

9 CVU103 17 16 ROOT

10 CVU302 22 16 ROOT

18 CVU106 1 20 ROOT

19 CVU207 6 20 ROOT

20 CVU107 12 20 ROOT

21 CVU108 21 21 ROOT

11 CVU110 15 26 ROOT

12 CVU111 6 24 ROOT

22 CVU93 1 1 W93

23 CVU194 7 1 ROOT

24 CVU94 1 1 W94

25 CVU244 17 1 ROOT

26 CVU144 22 1 ROOT

27 CVU97I X X W97

28 CVU97P X X W97

INJ W STD 13 -17 18 -26

PROD O STD 1 -5 6 -10 11 12 28

INJ G STD 27

YINJ 27

C COMPOSITION OF GAS

1.0 0.00 0 0 0 0 0 0 0

C

FPERF

WELL IW JW DTOP DBOT SKIN GRID

1 22 7 365 700 -1 ROOT

2 17 6 355 700 -1 ROOT

3 12 6 344 700 -1 ROOT
4 X X 342 700 -1 W97
5 1 7 332 700 -1 ROOT
13 1 1 325 700 -4 W99
14 7 11 328 700 -4 ROOT
15 1 1 329 700 -4 W100
16 17 12 342 700 -4 ROOT
17 22 12 358 700 -4 ROOT
6 1 16 318 700 -1 ROOT
7 6 16 313 700 -1 ROOT
8 11 16 318 700 -1 ROOT
9 17 16 340 700 -1 ROOT
10 22 16 356 700 -1 ROOT
18 1 20 314 700 -4 ROOT
19 6 20 300 700 -4 ROOT
20 12 20 319 700 -4 ROOT
21 21 21 367 700 -4 ROOT
11 15 26 314 700 -1 ROOT
12 6 24 390 700 -1 ROOT
22 1 1 319 700 -4 W93
23 7 1 367 700 -4 ROOT
24 1 1 314 700 -1 W94
25 17 1 390 700 -1 ROOT
26 22 1 390 700 -1 ROOT
27 X X 342 700 -1 W97
28 X X 342 700 -1 W97

WI 13-26

14*10.0

C

WI 4 27

2*6.0

C

QMAX 13-26

14*0

QMAX 1-12

12*0

PROD LIQUID 4

QMAX 4

625.0

QMAX 27

0

QMAX 28

0

ACTIVATE ALL

C

C

C

C

C PRODUCTION - INJECTION DATA

C

DATE 01 01 1994

C SWITCH DTMIN DTMAX DPMAX DSMAX DVMAX DZMAX

DT -1 0.0001 10 300

OVER ISAT

1 22 1 26 1 12 =7

GLIMTT LIMIT 1 -12

12*1000

BHP 4

100

700

PROD LIQUID 4

QMAX 4

625.0

QMAX 13 15 22 24

4*450

BHP 13-26

14*1700

14*700

DATE 01 06 1995

QMAX 4

0.0

BHP 27
2000
700
QMAX 27
2000.0
C SWITCH DTMIN DTMAX DPMAX DSMAX DVMAX DZMAX
DT-1 0.0001 1 300
OUTPUT SO SG
PRINT ARRAYS TNEXT
DATE 04 06 1995
OUTPUT SO SG
PRINT ARRAYS TNEXT
DATE 07 06 1995
OUTPUT SO SG
PRINT ARRAYS TNEXT
DATE 10 06 1995
OUTPUT SO SG
PRINT ARRAYS TNEXT
DATE 15 06 1995
OUTPUT SO SG
PRINT ARRAYS TNEXT
DATE 20 06 1995
PRINT ARRAYS TNEXT
DATE 25 06 1995
QMAX 27
0.0
DATE 15 07 1995
PROD LIQUID 4
QMAX 4
800
C 625
DATE 16 07 1995
DATE 18 07 1995
DATE 21 07 1995
DATE 24 07 1995
DATE 27 07 1995
DATE 30 07 1995
QMAX 4
625
C SWITCH DTMIN DTMAX DPMAX DSMAX DVMAX DZMAX
DT-1 0.0001 10 300
DATE 01 08 1995
DATE 15 08 1995
DATE 01 09 1995
DATE 15 09 1995
DATE 01 10 1995
DATE 15 10 1995
DATE 01 11 1995
DATE 01 12 1995
DATE 01 01 1996
DATE 01 02 1996
DATE 01 03 1996
DATE 01 04 1996
DATE 01 05 1996
DATE 01 06 1996
DATE 01 07 1996
DATE 01 08 1996
STOP
END

VIP-COMP Simulation Output Data in Summary Format

Time days	Gas Prod mcf/d	Oil Prod stb/d	Water Prod bbl/d	Gas Inj mcf/d	Water Inj bbl/d	Gas Prod mmscf	Oil Prod mstb	Water Prod mstb	Gas Inj mmscf	Water Inj mstb
518	20.492367	47.453844	577.54616	0.00E+00	628.19091	6.5172	15.072048	308.67795	0	285.51543
521	0.00E+00	0.00E+00	0.00E+00	2000	624.55306	6.5172	15.072048	308.67795	6	287.39734
524	0.00E+00	0.00E+00	0.00E+00	2000	598.1171	6.5172	15.072048	308.67795	12	289.23329
527	0.00E+00	0.00E+00	0.00E+00	2000	552.87095	6.5172	15.072048	308.67795	18	290.95233
532	0.00E+00	0.00E+00	0.00E+00	2000	462.76331	6.5172	15.072048	308.67795	28	293.46383
537	0.00E+00	0.00E+00	0.00E+00	2000	371.9645	6.5172	15.072048	308.67795	38	295.51262
542	0.00E+00	0.00E+00	0.00E+00	2000	287.30592	6.5172	15.072048	308.67795	48	297.11564
562	0.00E+00	0.00E+00	0.00E+00	0.00E+00	154.20021	6.5172	15.072048	308.67795	48	300.96248
563	1000	1.7825831	36.069967	0.00E+00	152.72448	7.5172	15.073831	308.71402	48	301.11521
565	1000	7.6093495	61.566299	0.00E+00	151.72593	9.5172	15.085921	308.8233	48	301.41877
568	1000	21.951968	234.05686	0.00E+00	156.99111	12.5172	15.13509	309.27855	48	301.8826
571	1000	315.21171	484.0992	0.00E+00	169.66909	15.5172	15.57128	310.60818	48	302.3753
574	811.88789	334.40204	465.59796	0.00E+00	188.77078	18.041478	16.589803	311.98966	48	302.91854
577	1000	332.71195	453.88018	0.00E+00	211.3158	20.681664	17.550086	313.42333	48	303.52682
579	533.04121	265.03753	359.96247	0.00E+00	226.79206	21.729297	18.08445	314.13897	48	303.97267
593	296.34659	153.30916	471.69084	0.00E+00	321.96757	27.557453	20.584664	320.38875	48	308.06449
610	239.12183	116.81105	508.18895	0.00E+00	403.04524	31.702948	22.706044	328.89237	48	314.60661
624	174.43293	93.855379	531.14462	0.00E+00	453.27824	34.390542	24.068722	336.2597	48	320.78986
640	126.91222	79.289847	545.71015	0.00E+00	495.71019	36.55086	25.402509	344.94591	48	328.5666
654	108.01441	71.638731	553.36127	0.00E+00	523.22835	38.126399	26.434129	352.66429	48	335.80337
671	90.82886	62.527536	562.47246	0.00E+00	547.93786	39.740621	27.534167	362.18925	48	345.02146
701	72.043219	57.120552	567.87945	0.00E+00	578.38409	42.078718	29.305434	379.16798	48	362.09759
732	60.262557	53.160807	571.83919	0.00E+00	598.97659	44.054077	30.988483	396.85993	48	380.47263
763	53.17639	51.079661	573.92034	0.00E+00	612.85782	45.767836	32.589193	414.63422	48	399.34003
792	48.421887	49.79278	575.20722	0.00E+00	622.06276	47.220257	34.045673	431.30274	48	417.28938
823	45.492646	48.967716	576.03228	0.00E+00	629.06429	48.660981	35.567597	449.15582	48	436.72268
853	42.974719	48.483696	576.5163	0.00E+00	634.11291	49.973913	37.026231	466.44719	48	455.69894
884	40.883033	48.101086	576.89891	0.00E+00	637.97143	51.261924	38.521078	484.32734	48	475.43891
914	39.005856	47.540046	577.45995	0.00E+00	640.75925	52.450269	39.952749	501.64567	48	494.63569
945	37.515797	47.224208	577.77579	0.00E+00	642.87986	53.628632	41.420594	519.55282	48	514.54458

*** APPENDIX "C" ***

TABLE C-1

DOE/CVU CO₂ Huff-n-Puff Test
Pre-demo/Injection/Soak/Production Testing

Date	Oil STB/D	Water Bbl/D	Daily Avg. Total Gas Mcf/D	Est. HC Gas Mcf/D	Cum. CO ₂ Mcf/D	CO ₂ Inj. MMcf/D	Avg. Tbg. Press. psig	Choke Size x/64"	Est'd. Total Fluid STB/D	% CO ₂ in gas, %	Cum. CO ₂ Prod., % Total Inj'd.
10/1/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/2/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/3/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/4/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/5/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/6/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/7/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/8/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/9/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/10/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/11/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/12/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/13/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/14/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/15/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/16/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/17/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/18/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/19/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/20/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/21/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/22/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/23/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/24/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/25/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/26/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/27/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/28/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/29/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/30/95	68	745	27.2	27.2	—	—	30	—	827	—	—
10/31/95	68	745	27.2	27.2	—	—	30	—	827	—	—
11/1/95	68	745	27.2	27.2	—	—	30	—	827	—	—
11/2/95	68	745	27.2	27.2	—	—	30	—	827	—	—
11/3/95	68	745	27.2	27.2	—	—	30	—	827	—	—
11/4/95	68	745	27.2	27.2	—	—	30	—	827	—	—
11/5/95	68	745	27.2	27.2	—	—	30	—	827	—	—
11/6/95	68	745	27.2	27.2	—	—	30	—	827	—	—
11/7/95	68	745	27.2	27.2	—	—	30	—	827	—	—
11/8/95	68	745	27.2	27.2	—	—	30	—	827	—	—
11/9/95	68	745	27.2	27.2	—	—	30	—	827	—	—
11/10/95	68	745	27.2	27.2	—	—	30	—	827	—	—
11/11/95	0	0	0	—	—	—	0	—	0	—	—
11/12/95	—	—	—	—	—	—	0	—	0	—	—
11/13/95	—	—	—	—	—	1.82	400	—	0	—	—
11/14/95	—	—	—	—	—	1.06	510	—	0	—	—
11/15/95	—	—	—	—	—	2.18	542	—	0	—	—
11/16/95	—	—	—	—	—	2.30	647	—	0	—	—
11/17/95	—	—	—	—	—	2.30	683	—	0	—	—
11/18/95	—	—	—	—	—	2.54	662	—	0	—	—
11/19/95	—	—	—	—	—	2.67	744	—	0	—	—
11/20/95	—	—	—	—	—	2.30	650	—	0	—	—
11/21/95	—	—	—	—	—	2.61	548	—	0	—	—
11/22/95	—	—	—	—	—	2.91	607	—	0	—	—
11/23/95	—	—	—	—	—	1.67	616	—	0	—	—
11/24/95	—	—	—	—	—	1.46	561	—	0	—	—
11/25/95	—	—	—	—	—	1.78	633	—	0	—	—
11/26/95	—	—	—	—	—	2.20	678	—	0	—	—
11/27/95	—	—	—	—	—	1.99	685	—	0	—	—
11/28/95	—	—	—	—	—	1.68	676	—	0	—	—
11/29/95	—	—	—	—	—	1.99	678	—	0	—	—
11/30/95	—	—	—	—	—	1.99	684	—	0	—	—
12/1/95	—	—	—	—	—	1.78	665	—	0	—	—
12/2/95	—	—	—	—	—	1.67	649	—	0	—	—
12/3/95	—	—	—	—	—	1.88	675	—	0	—	—
12/4/95	—	—	—	—	—	1.36	580	—	0	—	—
12/5/95	—	—	—	—	—	0.31	462	—	0	—	—

DOE/CVU CO2 Huff-n-Puff Test
Pre-demo/Injection/Soak/Production Testing

Date	Oil STB/D	Water Bbl/D	Daily Avg. Total Gas Mcf/D	Est. HC Gas Mcf/D	Cum. CO2 Mcf/D	CO2 Inj. MMcf/D	Avg. Tbg. Press. psig	Choke Size x/64"	Est'd. Total Fluid STB/D	% CO2 in gas, %	Cum. CO2 Prod., % Total Inj'd.
12/6/95	—	—	—	—	2.20	630	—	0	—	—	—
12/7/95	—	—	—	—	2.62	701	—	0	—	—	—
12/8/95	—	—	—	—	0.52	603	—	0	—	—	—
12/9/95	—	—	—	—	—	683	—	0	—	—	—
12/10/95	—	—	—	—	—	737	—	0	—	—	—
12/11/95	—	—	—	—	—	764	—	0	—	—	—
12/12/95	—	—	—	—	—	779	—	0	—	—	—
12/13/95	—	—	—	—	—	792	—	0	—	—	—
12/14/95	—	—	—	—	—	803	—	0	—	—	—
12/15/95	—	—	—	—	—	823	—	0	—	—	—
12/16/95	—	—	—	—	—	831	—	0	—	—	—
12/17/95	—	—	—	—	—	846	—	0	—	—	—
12/18/95	—	—	—	—	—	866	—	0	—	—	—
12/19/95	—	—	—	—	—	857	—	0	—	—	—
12/20/95	—	—	—	—	—	829	—	0	—	—	—
12/21/95	—	—	—	—	—	863	—	0	—	—	—
12/22/95	—	—	—	—	—	879	—	0	—	—	—
12/23/95	—	—	—	—	—	872	—	0	—	—	—
12/24/95	—	—	—	—	—	870	—	0	—	—	—
12/25/95	—	—	—	—	—	866	—	0	—	—	—
12/26/95	—	—	—	—	—	868	—	0	—	—	—
12/27/95	4	1	840	0	840	—	754	16	425	100.0%	0.02
12/28/95	6	0	674	0	1514	—	778	16	343	100.0%	0.03
12/29/95	0	0	872	0	2386	—	741	16	436	100.0%	0.05
12/30/95	0	3	836	0	3222	—	656	16	421	100.0%	0.07
12/31/95	6	3	836	0	4058	—	644	16	427	100.0%	0.08
1/1/96	10	0	929	0	4987	—	652	16	474	100.0%	0.10
1/2/96	7	0	952	0	5939	—	652	16	483	100.0%	0.12
1/3/96	18	0	972	51	6860	—	632	16	505	94.8%	0.14
1/4/96	37	0	895	47	7708	—	607	16	484	94.8%	0.16
1/5/96	55	0	918	48	8578	—	617	17	514	94.8%	0.18
1/6/96	35	0	445	27	8996	—	607	17	258	93.9%	0.19
1/7/96	49	0	594	38	9552	—	631	17	346	93.7%	0.20
1/8/96	70	8	884	56	10380	—	645	18	521	93.7%	0.22
1/9/96	—	—	763	48	11095	—	563	18	382	93.7%	0.23
1/10/96	40	0	393	25	11463	—	593	13	237	93.7%	0.24
1/11/96	63	1	414	26	11851	—	613	14	271	93.7%	0.25
1/12/96	70	6	434	28	12257	—	580	14	293	93.7%	0.26
1/13/96	60	11	392	25	12624	—	599	14	267	93.7%	0.26
1/14/96	59	8	388	25	12988	—	590	15	261	93.7%	0.27
1/15/96	63	24	455	29	13414	—	554	14	315	93.7%	0.28
1/16/96	65	32	388	39	13763	—	537	14	291	89.9%	0.29
1/17/96	—	—	—	—	13763	—	—	14	0	89.9%	0.29
1/18/96	57	32	293	30	14026	—	531	14	236	89.9%	0.29