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CO2 Huff-n-Puff Process In A Light Oil Shallow Shelf Carbonate Reservoir

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By
John Prieditis
Scott Wehner

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

Jerry F. Casteel, Project Manager
National Petroleum Technology Office
P.O. Box 3628
Tulsa, OK 74101

Prepared by:
Texaco Exploration & Production Inc.
PO Box 3109
Midland, TX 79702

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ABSTRACT

The application of cyclic CO_2, often referred to as the CO_2 Huff-n-Puff process, may find its niche in the maturing waterfloods of the Permian Basin. Coupling the CO_2 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 CO_2 Huff-n-Puff process in the Grayburg and San Andres formations; a light oil, shallow shelf carbonate reservoir that exists throughout 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 CO_2 flooding is the process of choice for enhancing recovery of light oils[3] and already accounts for over 12% of the Permian Basin's daily production.[4] There are significant probable reserves associated with future miscible CO_2 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 CO_2 H-n-P process is being investigated as a near-term option to mitigate the negative cash-flow situation--allowing acceleration of inventoried miscible CO_2 projects when coupled together.

The CO_2 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 reservoirs[7]. 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 CO_2 H-n-P process are not lithology dependent.

It is anticipated that this project will show that the application of the CO_2 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 second budget period. Details of tasks conducted under the first budget period and initial tasks of the second budget period were reported in previous annual reports[12,13].

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[12].

The 1995 Annual Report[13] provided some conclusions to some of the work previously reported. Specifically, the report dealt 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.

The 1996 Annual Report provides the final results from the field demonstration, its history match via computer simulations, cost and economic considerations, and relevant conclusions to date.

A successful demonstration of the CO_2 Huff-n-Puff process could have wide application. The proposed technology promises several advantages. It is hoped that the CO_2 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 CO_2 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 (CO_2) 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 CO_2 project in the CVU. However, the current market precludes acceleration of such a capital intensive project in many similar reservoirs. This is a common finding throughout the Permian Basin SSC reservoirs. In theory, it is believed that the "immiscible" CO_2 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 CO_2 project. The DOE partnership provides some relief to the associated Research & Development 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 CO_2 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 CO_2 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 CO_2 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 CO_2 deliveries already in place, a successful demonstration of the CO_2 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 CO_2 miscible project. It could maximize recoveries from smaller isolated leases which could never economically support a miscible CO_2 project. The process, when applied during the installation of a full-scale CO_2 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 CO_2 miscible projects are focused on the "sweet spots" of a property, the CO_2 H-n-P process could concurrently maximize recoveries from non-targeted acreage. An added incentive for the early application of the CO_2 H-n-P process is that it could provide an early measure of CO_2 injectivity of future full-scale CO_2 miscible projects and improve real-time recovery estimates--

reducing economic risk. It is hoped that the CO_2 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 CO_2 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 second budget period. Details of tasks conducted under the first budget period and initial tasks of the second budget period were reported in previous annual reports[12,13].

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[12].

The 1995 Annual Report[13] provided conclusions to some of the work previously reported. Specifically, the report dealt 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 suggested that reservoir characterization of flow units is not as critical for a CO_2 H-n-P process as for a miscible flood. Entrapment of CO_2 by gas hysteresis was considered the dominant recovery factor for a given volume of CO_2. The repetitive application of the process was found to be unwarranted in a waterflooded environment.

The 1996 Annual Report provides the final results from the field demonstration, its history match via computer simulations, along with cost and economic considerations.

The findings to date show that the field demonstration did not perform as forecast. The forecast assumed that a large trapped gas saturation would occur. The incremental oil recovered was only equivalent to the deferred production during the injection and soak periods. Furthermore, it is apparent that 100% of the injected CO_2 is being recovered. These are the trademarks for the lack of a trapped gas saturation. Previous simulation work indicated that a trapped gas saturation was the mechanism required for success. Several possibilities exist for this deficiency. First, the water may have dissolved the CO_2 saturation. Secondly, the absence of a trapped gas saturation

might be due to pore throat size, porosity-type, lithological characteristics, or a combination of these factors that are not currently understood.
In addition, based on simulation exercises, it is apparent that there may be a rate dependency component to the ultimate success and efficiency of this technology. Simulation results indicate that the oil production rate is increased when the gas production rate is increased. This suggests that a well be equipped for high gas production rates rather than trying to initially flow the well before returning production equipment to the wellbore. Restricting the gas rate restricts the oil production rate. Furthermore, since a gas disposal restriction exists at CVU, it should not be considered for further demonstrations.

It is interesting to note that near-wellbore gas trapping of CO_2 has been cited as one possible cause of reduced injectivity following Water-Alternating-Gas (WAG) injection methods employed in many miscible CO_2 floods. The offset East Vacuum Grayburg San Andres Unit miscible CO_2 flood, operated by Phillips, is one of the few Permian Basin CO_2 floods that has not experienced any appreciable reduction in injectivity during 12 years of WAG operations even though many of the other shallow shelf carbonate reservoirs experience 30 to 50 percent reductions in water injectivity following the introduction of CO_2 to the reservoirs. If it can be inferred that reduced injectivity in WAG operations is related to gas trapping, then Vacuum field is not a good candidate for further testing of the Huff-n-Puff technology. Oxy has been experimenting with Huff-n-Puff technology in the Welch field of West Texas. Oxy's Huff-n-Puff results have been favorable enough to expand their program. An offset miscible CO_2 flood within the Welch field showed reduced injectivity in WAG operations. This further suggests that the technology should be applied to another reservoir that has documented WAG injectivity reductions to validate the hypothesis. The Huff-n-Puff technology might become a valuable indicator of potential injection rates when designing a miscible CO_2 flood. Injectivity is one of the main parameters affecting the economics of these large scale projects. The failure of the Huff-n-Puff might indicate favorable expectations of injection, whereas a positive response may suggest injectivity reductions--thus the need for the parallel implementation of the Huff-n-Puff technology.

An associated lifting cost benefit was realized during the demonstration resulting from the reduction in electrical load. Even though the oil recovery was equivalent to the deferred production, it was recovered during a period that experienced no electrical costs during the injection, soak and flowing periods. Once the well was returned to pumping, it has continued to experienced less load due to reduced water influx.

Pursuit of a second demonstration site, amenable to gas trapping is underway. Following a successful demonstration, the development of guidelines for the cost-effective selection of candidate sites, along with estimation of recovery potential, will be pursued.

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 CO_2 Flooding was initiated in 1985 by Phillips in the southeastern portion of the field, immediately east of the CVU, and to the west of CVU in 1996 at the State 35 Unit (Mable-Hale). **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.

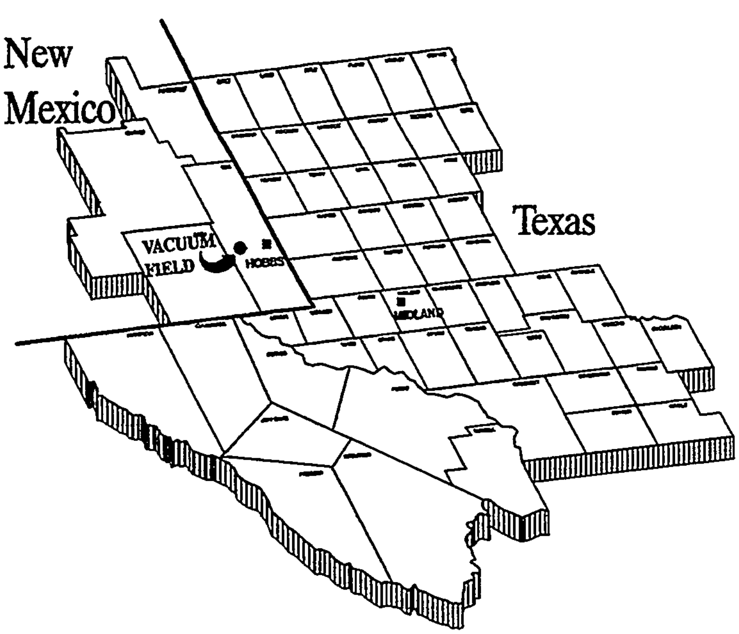


Fig. 1: Regional location of Central Vacuum Unit.

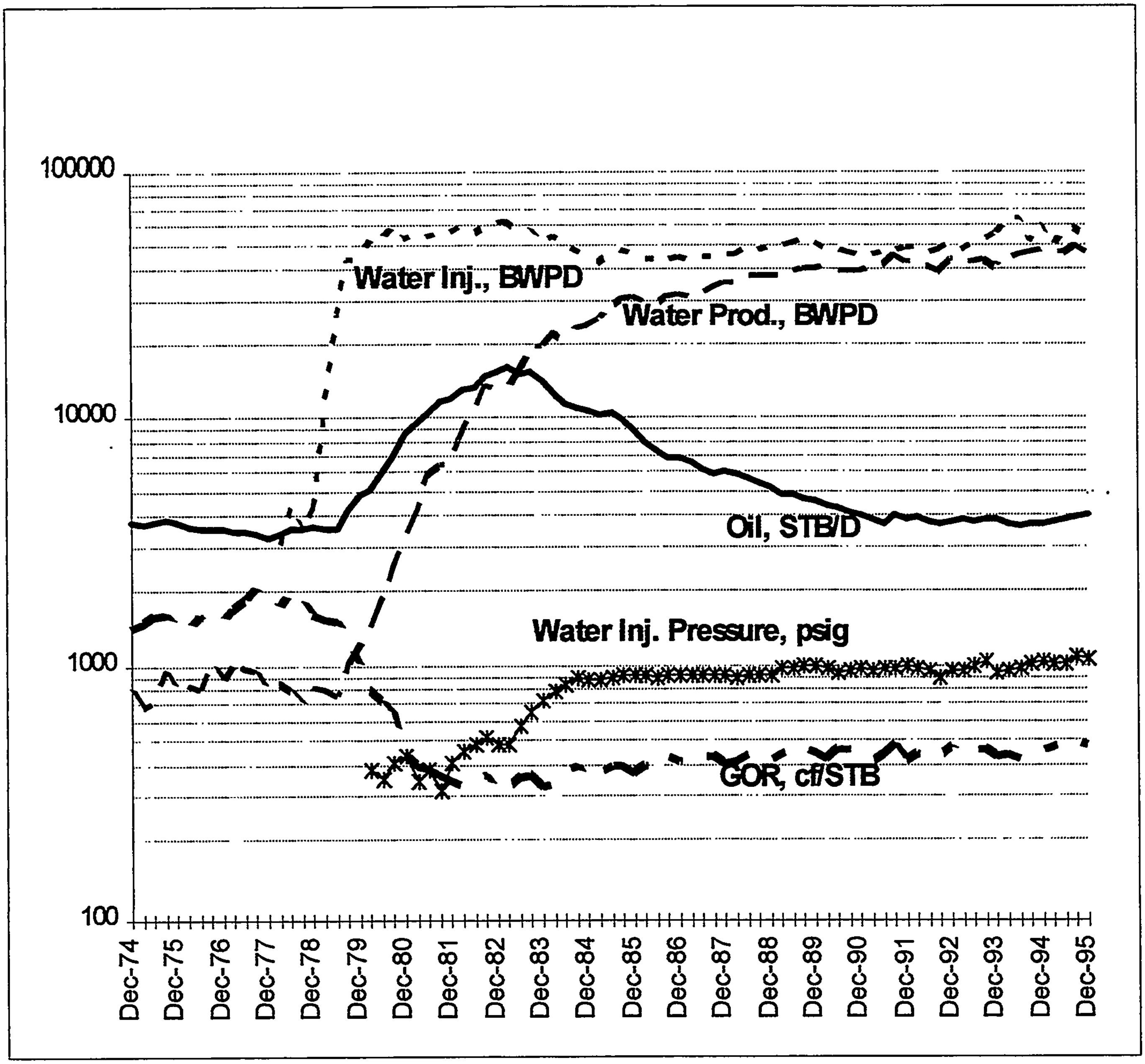


Fig. 2: Central Vacuum Unit production and injection history. Textbook waterflooding character.

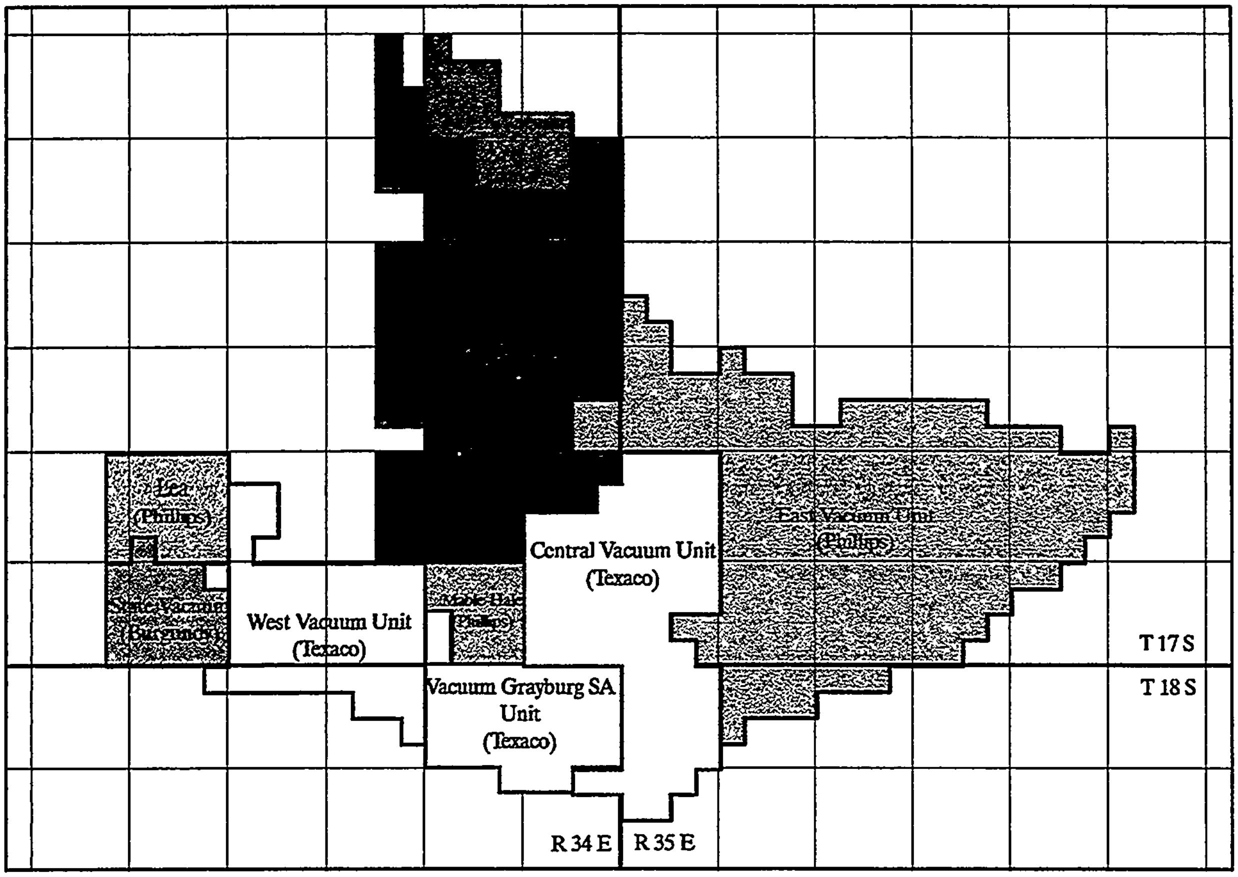


Fig 3: Unitized Acreage of Vacuum Field, Lea Co., New Mexico.

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**.

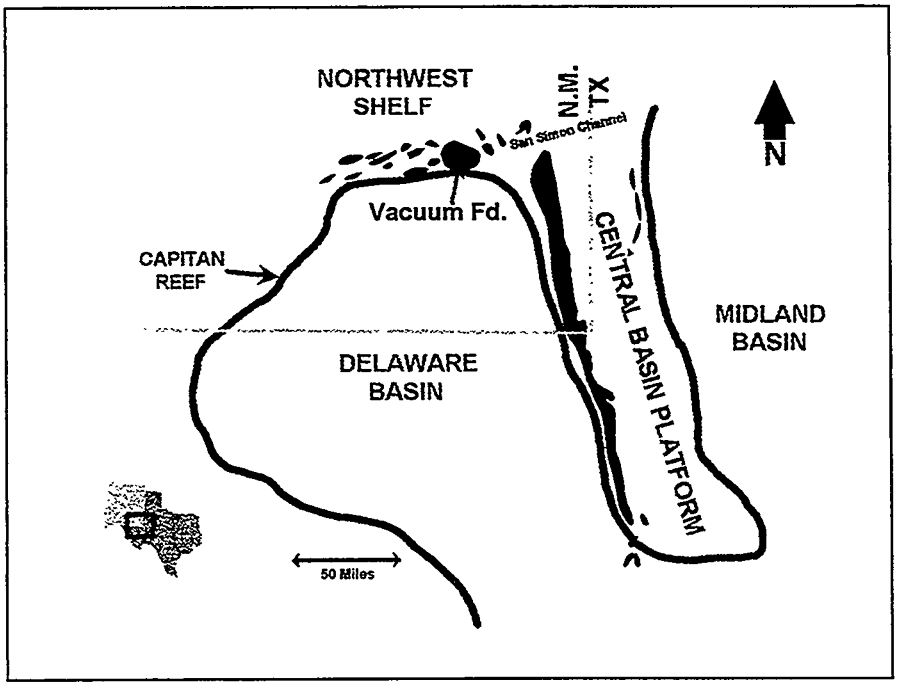


Fig. 4: Permian Basin and relative position of Vacuum field.

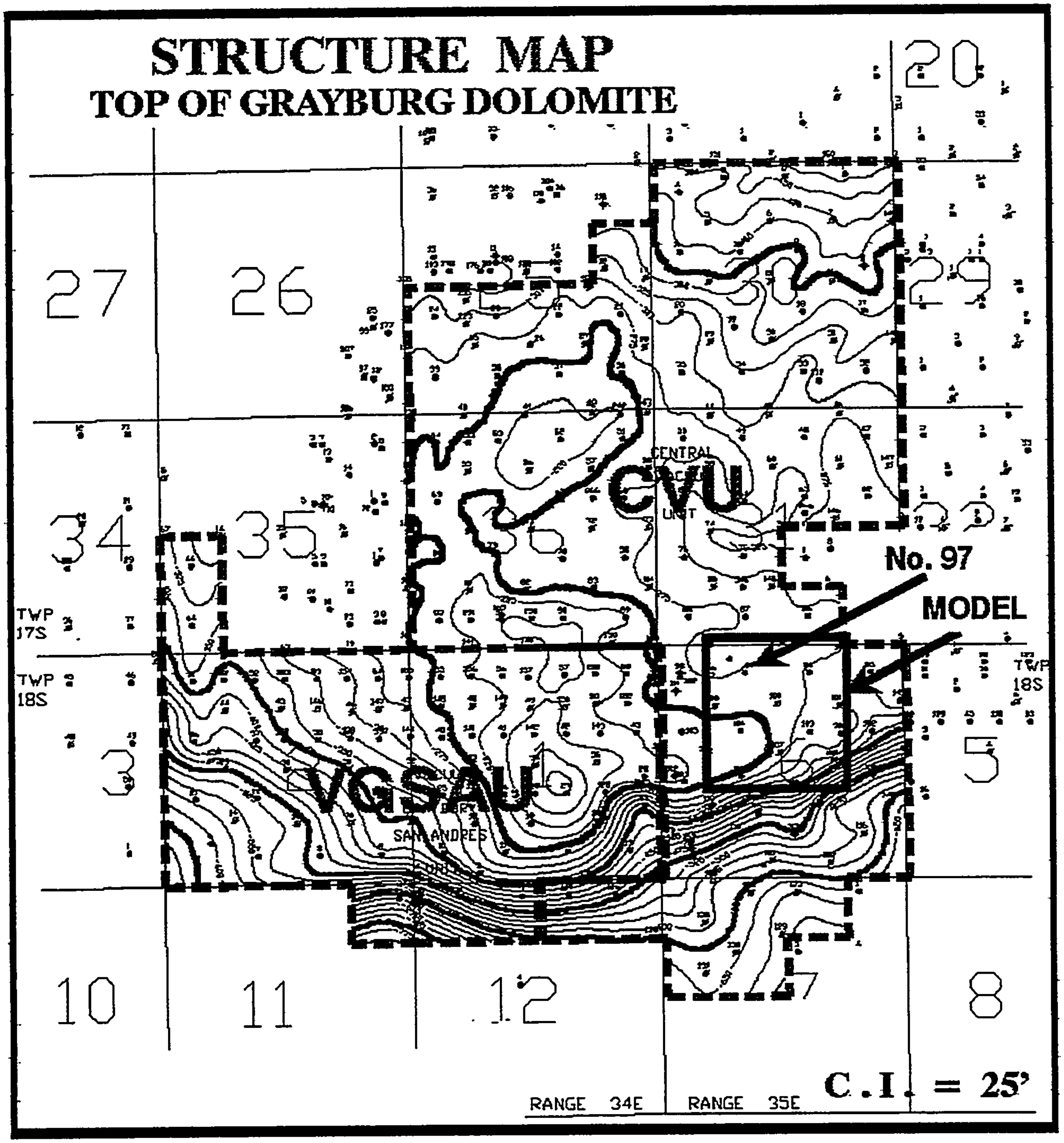


Fig. 5: Limits of Central Vacuum Unit with structural contours on Grayburg Dolomite. Shelf-Basin margin

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 crystaline 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 CO_2 H-n-P process.

Brief of Project & Technology Description

This project has two defined budget periods. This report concludes a discussion of work predominantly initiated and covered in the 1995 Annual Report[13]; concluding 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, history matching the results, and an evaluation of costs and economical considerations.

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 CO_2 required, best operational practices, and expected oil recoveries from the demonstration sites.

Basic Theory and Objective. Under certain conditions the introduction of CO_2 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.

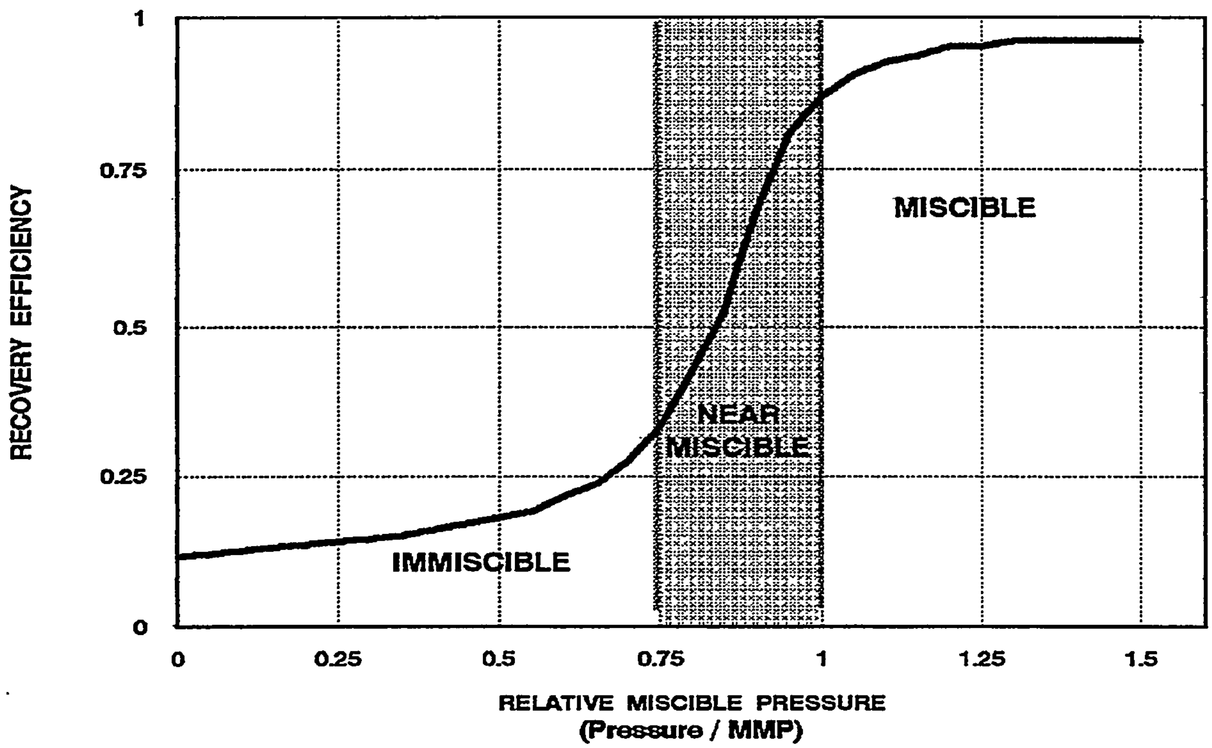


Fig. 6: Generalized Recovery Efficiency vs. Relative Minimum Miscibility Pressure.

The CO_2 H-n-P process has traditionally been applied to pressure depleted reservoirs. The CO_2 is injected down a production wellbore in an immiscible condition. Theoretically the CO_2 displaces the majority of the mobile water within the wellbore vicinity, while bypassing the oil-in-place. The CO_2 then absorbs into both the oil and remaining water. The water will absorb CO_2 quickly but only a relatively limited quantity. Conversely, the oil can absorb a significant volume of CO_2 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 CO_2 H-n-P process. **Fig.** 7 visually illustrates the proposed CO_2 H-n-P process.

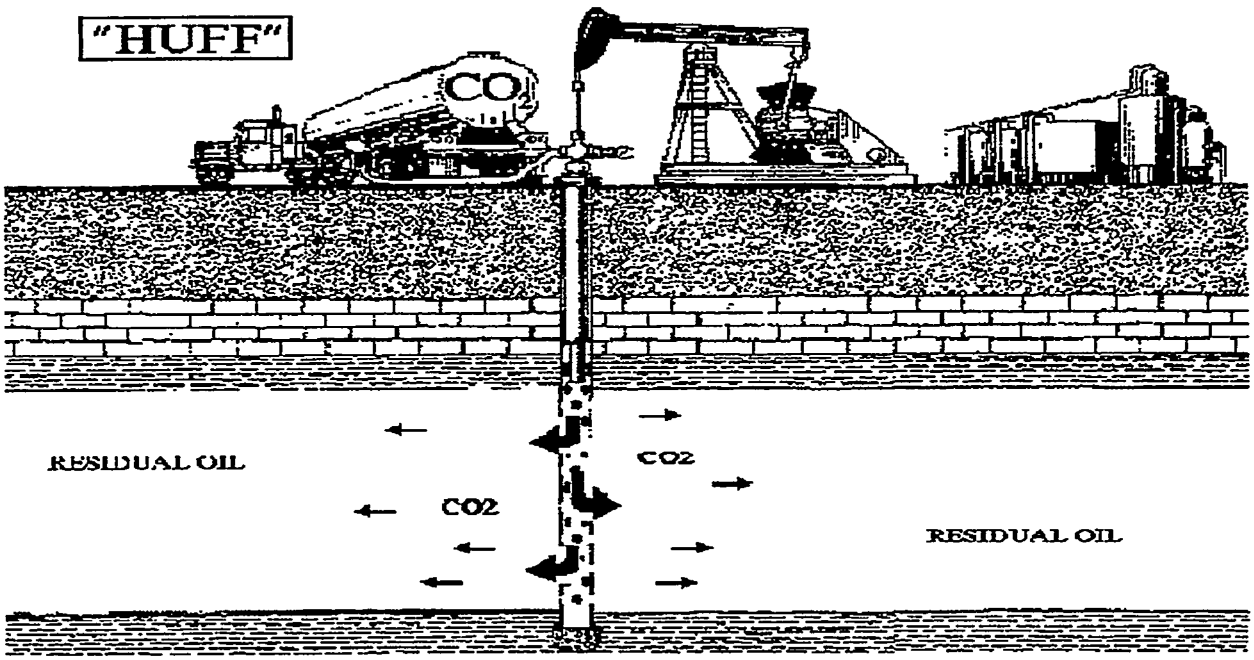


Fig 7a: Injection or "Huff" phase of the Project

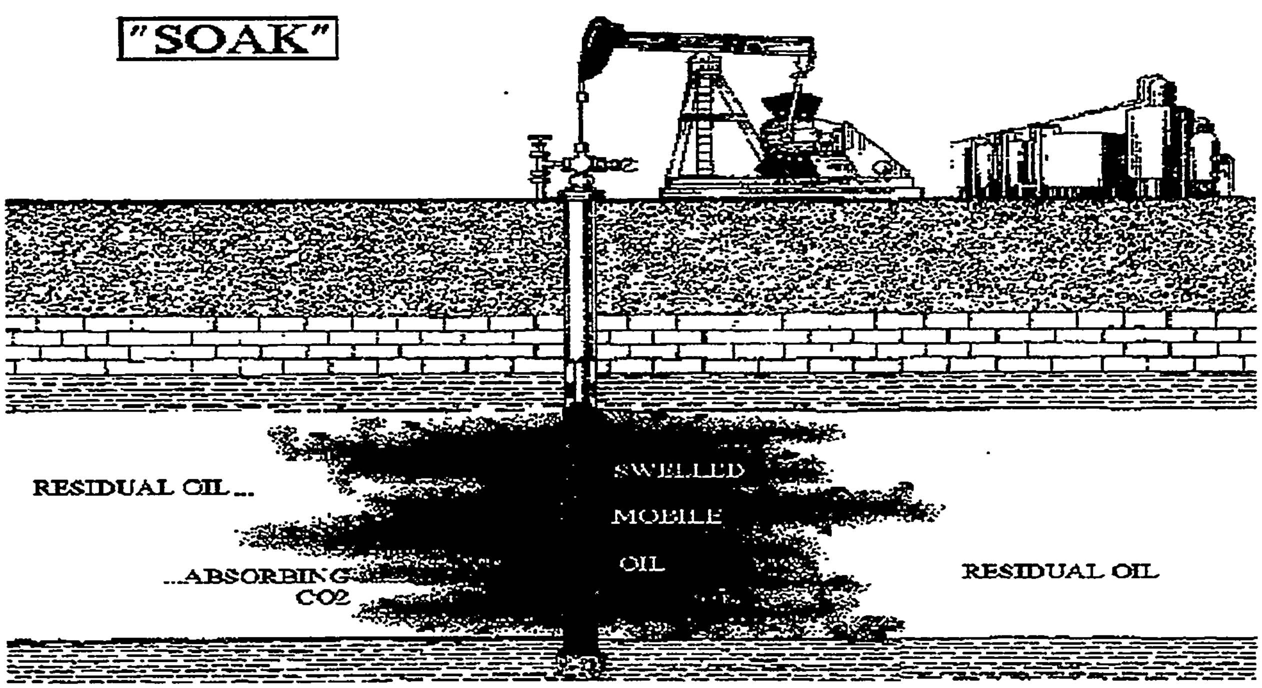


Fig. 7b: The "Soak" phase of the Project.

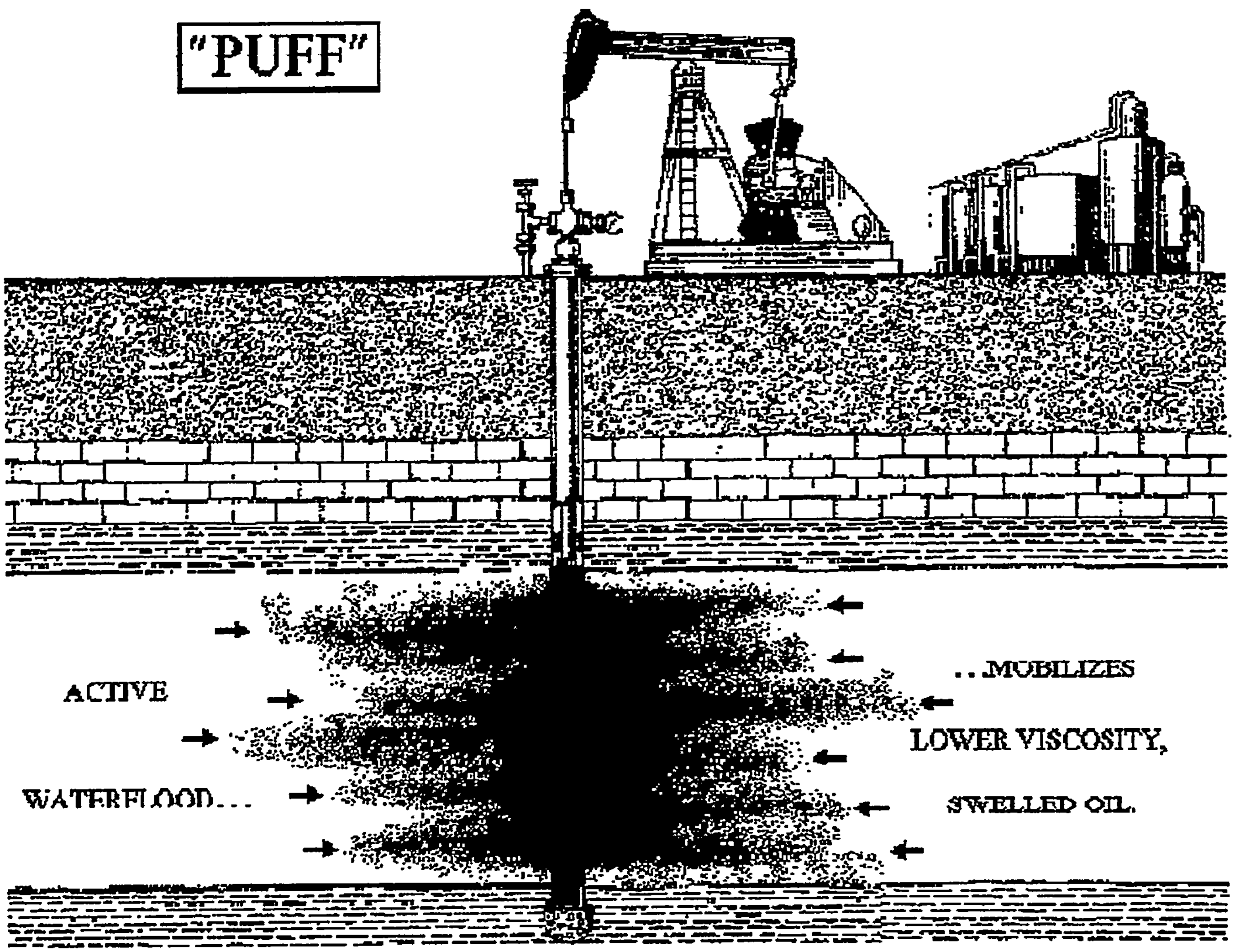


Figure 7c: The production or "Puff" phase of the Project

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.

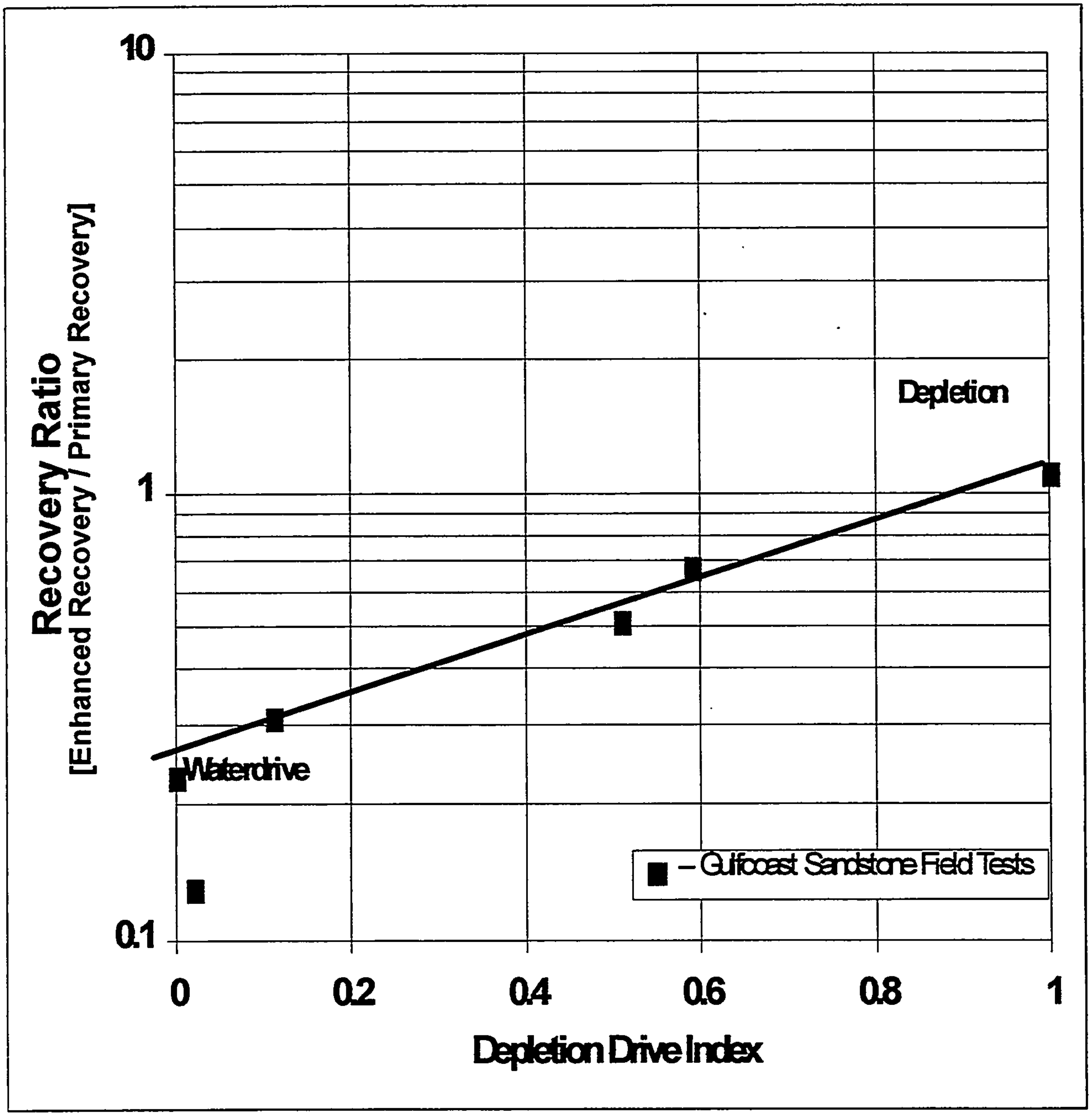


Fig. 8: Relation between Drive Index and Recovery Efficiency of the CO_2 H-n-P process. Developed from Gulf-Coast sandstone reservoir field trials.

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 CO_2 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 CO_2 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 CO_2, 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 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[12]. Some final reservoir characterization comments regarding variances between geostatistical findings, and the waterflood review were provided in this 1995 Annual Report[13]. Additionally, the findings from the parametric simulations, site-specific simulation history match and forecast, and field demonstration of the CO_2 H-n-P process were also provided. The 1996 Annual Report provides the final results from the field demonstration, its history match via computer simulations, along with a discussion of costs and economic considerations, relevant conclusions to date, and future activities.

Field Demonstration

Review. Even though parametric simulation exercises suggested reservoir heterogeneity would not play a large role[13], 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 CO_2 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. The well was drilled in 1938 and completed open hole. A volume of 50,000 McfCO_2 was trucked to the field site. 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 CO_2 beyond the interwell distance if the 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. average radius of CO_2.

The production equipment was removed from the wellbore. Since the well had been acidized in recent months no further remedial action was performed. An on-off tool and injection packer trimmed for CO_2 service was set above the open hole section.

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 CO_2 injection commenced at CVU No. 97.

Frequent and detailed testing was conducted for the duration of the project. A dedicated horizontal, three-phase test separator was set at the well site. Data gathering was automated. Flowing tubing pressure, casing pressure, and temperature were monitored continuously. Liquid volumes were measured daily. Gas production rates and volumes were also measured. Automated gas sampling provided a daily sample for gas chromatography. Liquid samples were initially gathered daily for visual inspection, API gravity determination, and occasional compositional analysis. The test separator dumped liquids to the existing production satellite. Polyethylene pipe was used exclusively to tie the well and separator together, and separator into existing assets.

Air quality regulations would not permit venting the hydrocarbon enriched CO_2 produced gas stream to the atmosphere. The produced gas was delivered via an existing pipeline to a nearby CO_2 processing facility.

Field Demonstration Results. Injection was initiated November 13 and completed on December 7, 1995. Based on the offset miscible CO_2 flood injection rates and pressures, an average rate of 1,500 McfCO_2/Day was expected in the demonstration. Actual injection averaged 2,210 McfCO_2/Day over 23 days net injection. 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 survey once half the target volume was injected. The CO_2 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 for the injection phase. This supported the simulation findings.

Once the CO_2 was in place offset water injectors were returned to active service. CVU No. 97 was then shut-in for a 20-day soak period. Wellhead pressure averaged 630 psig during the last week of injection and 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. It is believed that this phenomenon would be beneficial to the demonstration rather than detrimental.

CVU No. 97 was returned to active status under flowing conditions on December 27, 1995. Early flowing tubing pressure averaged 631 psig with choke settings between 13/64 in. and 18/64 in. Liquid hydrocarbon production was initially too small to measure and began increasing on the third day. Samples were collected and retained. The fluid was initially a transparent straw color (41°API) suggesting that lighter hydrocarbons were being effected (or paraffins & asphaltenes were being left behind). The well is currently producing the field normal 38°API crude. The well had achieved a 70 BOPD rate by the tenth net day of flow-back (average pre-demonstration was 68 BOPD). Production was quite volatile. The well initially flowed on various choke settings, but eventually loaded up. An Electrical Submersible Pump was run into the wellbore in early March, 1996. Following some minor operational problems, the well peaked at 184 BOPD. However, production declined rather sharply following this peak. Previous simulation exercises suggested that the peak oil response would not occur until 60% of the CO_2 had been produced back. The peak actually occurred at about 55% CO_2 recovery. The well has continued on a relatively shallow steady decline and is producing approximately 55 BOPD as of the date of this report.

Initially, gas production averaged 901 Mscf/Day. Gas production was not allowed to exceed 1,000 Mscf/D due to disposal limitations. Compositional analyses of the gas stream shows that early gas rates were above 90 mole-% CO_2. The CO_2 production steadily fell to 68 mole-% CO_2 by July, 1996. The daily monitoring of the demonstration ended in July, 1996 because it was apparent the well's production streams had stabilized near the pre-demonstration rates. A random sampling of gas from the well one year after return to production still indicates an elevated CO_2 concentration at the well (i.e., over 40%).

The magnitude of the gas production volumes are in question. Even after an attempt at accounting for in-situ CO_2, material balance suggests that a volume equal to 140% of the injected CO_2 volume had been produced by July, 1996 and 150% by the end of the year. The well continues to produce relatively high gas volumes compared to its offsets. However, the earlier gas rate itself is likely in error. The gas rate stopped declining around April, 1996. When the well was placed through the field facilities, the rate, although higher than offsets, was much lower than those measured in the test facility through July, 1996. The volume probably dropped below the measuring range for the meter utilized on the test separator around April, 1996. It is probably safe to say that the well will recover 100% of the injected CO_2.

The accuracy of either the gas test rates/volumes, sampling procedures, laboratory analysis, or a combination of each remain suspect. However, the laboratory analysis seems to be an unlikely cause due to the level of accuracy obtained from consistent standard industry practices. Although sampling procedures are questionable, the resulting error would likely be a lower CO_2 percentage measured, not higher. All the H-n-P simulations, including all the parametric and site specific cases, indicated that increased CO_2 production can last for well over a year. Consequently, the continued production of a high concentration of CO_2 (i.e., as much as 40%) is consistent with the simulation results. The error seems to be with the measured gas rates. If some assumptions are made in decline behavior of the gas rate from April, 1996 to the monthly rates measured in the field facilities during the last half of the year, the figures are more realistic--but still 20% high. The frequency of measurements could account for much of this discrepancy.

It is interesting to observe that although predicted oil response from the site-specific simulations (forecast & demonstration history match discussed later in this report) are substantially different, the predicted GOR for all cases are very similar after about 150 days. The GOR for the simulated base waterflood remained at about 430 Scf/STB, whereas the GOR for the H-n-P cases remained substantially higher and was above 700 Scf/STB even after a year. The simulations were done only out to about a year, but the GOR appears to be declining only very gradually and would be expected to remain high well into the second year--as has been seen in the field demonstration.

The concentrations of the produced gas streams were not reported in the simulation outputs. However, the concentration of CO_2 can be approximated because the increased GOR above the base of 430 Scf/STB is due primarily to the presence of CO_2. Using this approximation, which is fairly good, the fraction of CO_2 for a given GOR can be estimated with the following formula:

$$CO_2 \text{ fraction} = ((0.05 * 430) + (GOR - 430)) / GOR$$

Using this formula, the anticipated fraction of CO_2 in the produced gas can be expected to be above 0.40 even a year after the start of production as indicated in **Table 1** for the two history match cases discussed later in this report.

Table 1: Comparison of Estimated CO_2 Fraction based on Simulations.

Simulation Case	Days after Start of Production	GOR	**Estimated CO_2 Fraction**
Actual Initial Gas Rates	336	724	**0.43**
1000 Msf/D Gas Limit	336	705	**0.42**

Offset producers were monitored on a regular basis for CO_2 breakthrough. Levels remained in the normal 4-5% background range. A check one year after injection shows somewhat elevated

CO_2 levels in the two immediate offset wells. The offsets show 31-39 mole-% CO_2. These elevated findings may represent the influence of spent acid due to recent workover activity.

It is noteworthy to point out that although hydrocarbon production expectations have not been achieved at this specific test site, there was a period that experienced a favorable reduction in operating expenses. During the injection, soak and flowing periods there were no electrical costs. Electrical load was also significantly reduced during the early pumping period when water rates were 100% to 33% below pre-demonstration levels. No appreciable water production was seen initially. As expected, the water production slowly increased over a six month period and approached the pre-demonstration rates. The water remains on average 17% short of the original rate after one year of production. Although there are a few signs of paraffin buildup and scaling (inspection of downhole equipment), the lower than forecast oil production result is felt to be due to a lack of gas trapping in the matrix since nearly 100% of the injected CO_2 volume is expected to be recovered. The reduced water rate may be impacted by the remaining CO_2 saturation. More discussion of this conclusion is found in the history match discussion later in this report.

Fig. 9 provides the field demonstration history through mid-July, 1996. Supporting data is provided in **Appendix "A"**.

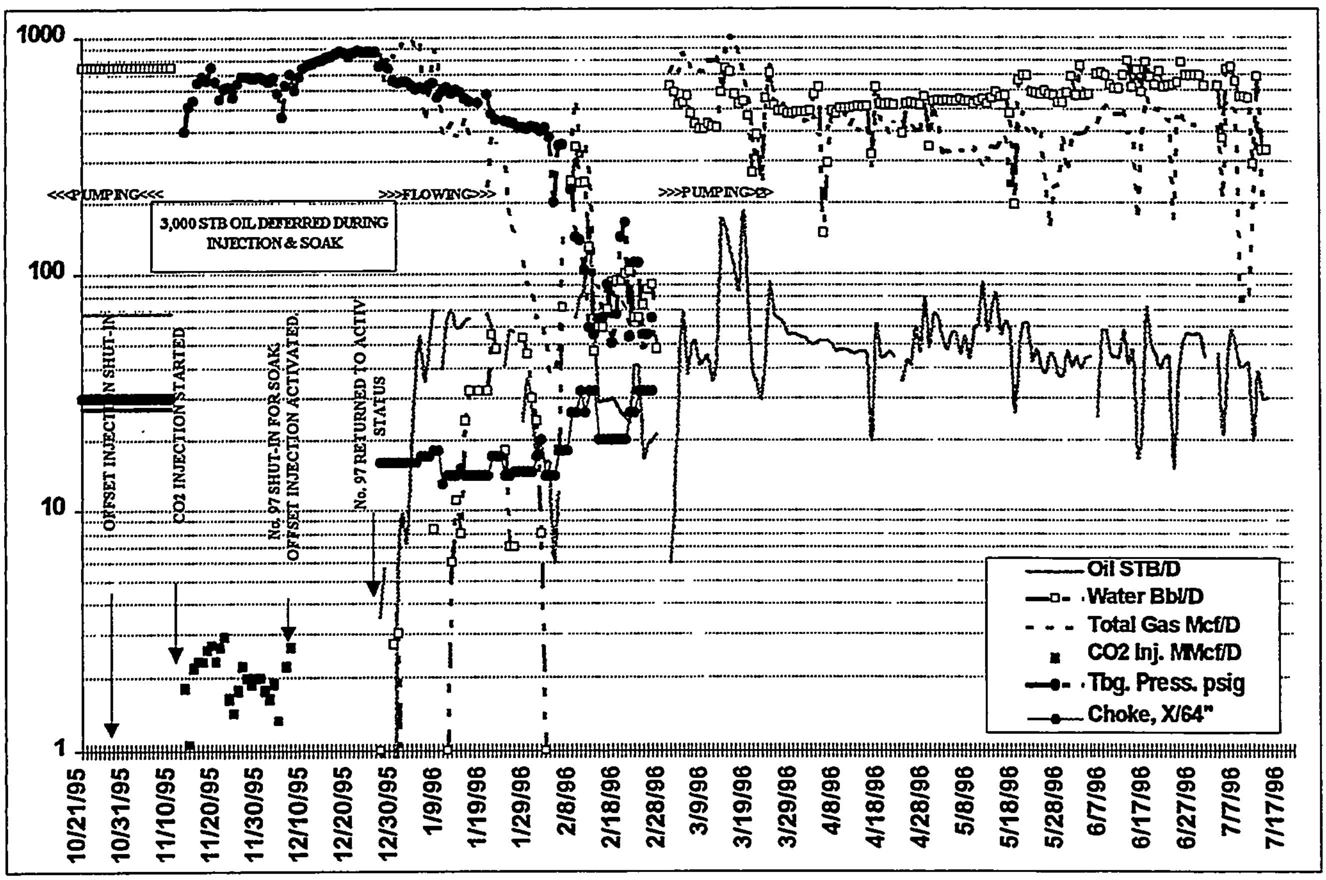


Fig. 9: CO_2 H-n-P Demonstration History.

Compositional Simulation Studies

The reservoir characterization work[12] 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 CO_2 and oil.[12]

A parametric simulation study of the CO_2 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 to forecast recoveries. The site-specific simulation was later used to history match the CO_2 H-n-P demonstration.

Review of Parametric Simulations.[14] This work is discussed in detail within the 1995 Annual Technical Report[13], but has been repeated here mostly in its entirety for reference purposes. A 25 layer radial model 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.

The reservoir parameters investigated in the parametric 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 CO_2 slug size, the CO_2 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.

Commercial reservoir simulators normally do not directly incorporate a number of the mechanisms which have been identified or suggested as being present in the CO_2 H-n-P process. As part of the parametric study, 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 approximated, if desired. Diffusion, which is approximated by an increase in the gas-oil capillary pressure, 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 CO_2 utilization, in this parametric study could have been improved if these options had been incorporated in the predictions. However, they were not invoked during the parametric study but were instead left to be used as needed for the history matching of the demonstration.

Typical H-n-P performance for a 25,000 McfCO_2 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 CO_2) with little water or oil. A large percentage of the CO_2 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 CO_2 utilizations were in the 10 Mcf/STB range, which are similar to the factors for standard CO_2 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.

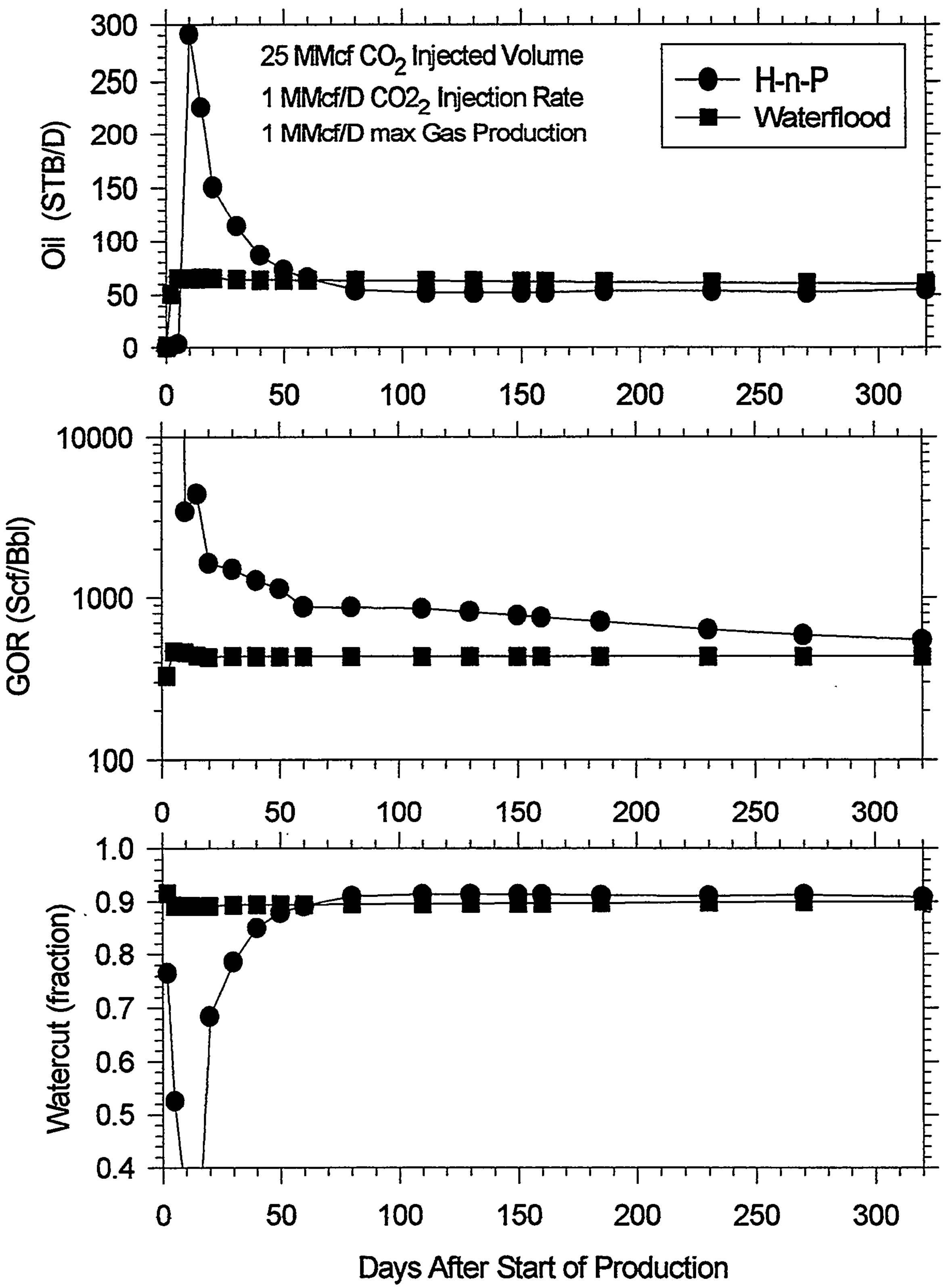


Fig. 10: Typical Simulated CO_2 H-n-P Performance.

Most of the CO_2 which was injected was produced back before or during the peak oil production. In the model, the CO_2 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.

Parametric Study Results. 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 CO_2 floods which are very sensitive to reservoir heterogeneity. An explanation can be provided by considering the differences in the standard CO_2 flood and the H-n-P. In a standard flood, high reservoir heterogeneity degrades performance because CO_2 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 CO_2 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 CO_2 permanently channels away.

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, 15]

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 CO_2 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.

The original idea of the CVU H-n-P process was to try to inject the CO_2 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 CO_2 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 CO_2 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 affected the incremental oil production, but not to a very large extent. 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 CO_2 injected. As the **volume of CO_2** was increased, the incremental oil recovery was increased, but also the start of oil production during the puff was delayed. The associated deferred oil volume also increased accordingly.

In agreement with previous simulation studies, soak times longer than a few days did not produce different results.[8,15] 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 CO_2 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, waterdrive reservoir.[16] 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 CO_2 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 with a well-rate constraint rather than a bottom-hole pressure constraint.

Summary of Parametric Study. Reservoir description was found not to be as important a parameter in a H-n-P as in a standard CO_2 flood. This indicates that most wells could be H-n-P candidates unless they have problems that would cause the CO_2 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 CO_2 volume injected, similar to typical miscible floods.

Review of the Site-Specific Simulation Study. The majority of this work is discussed in detail within the 1995 Annual Technical Report[13], but has been repeated here mostly in its entirety for reference purposes. 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 were 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.

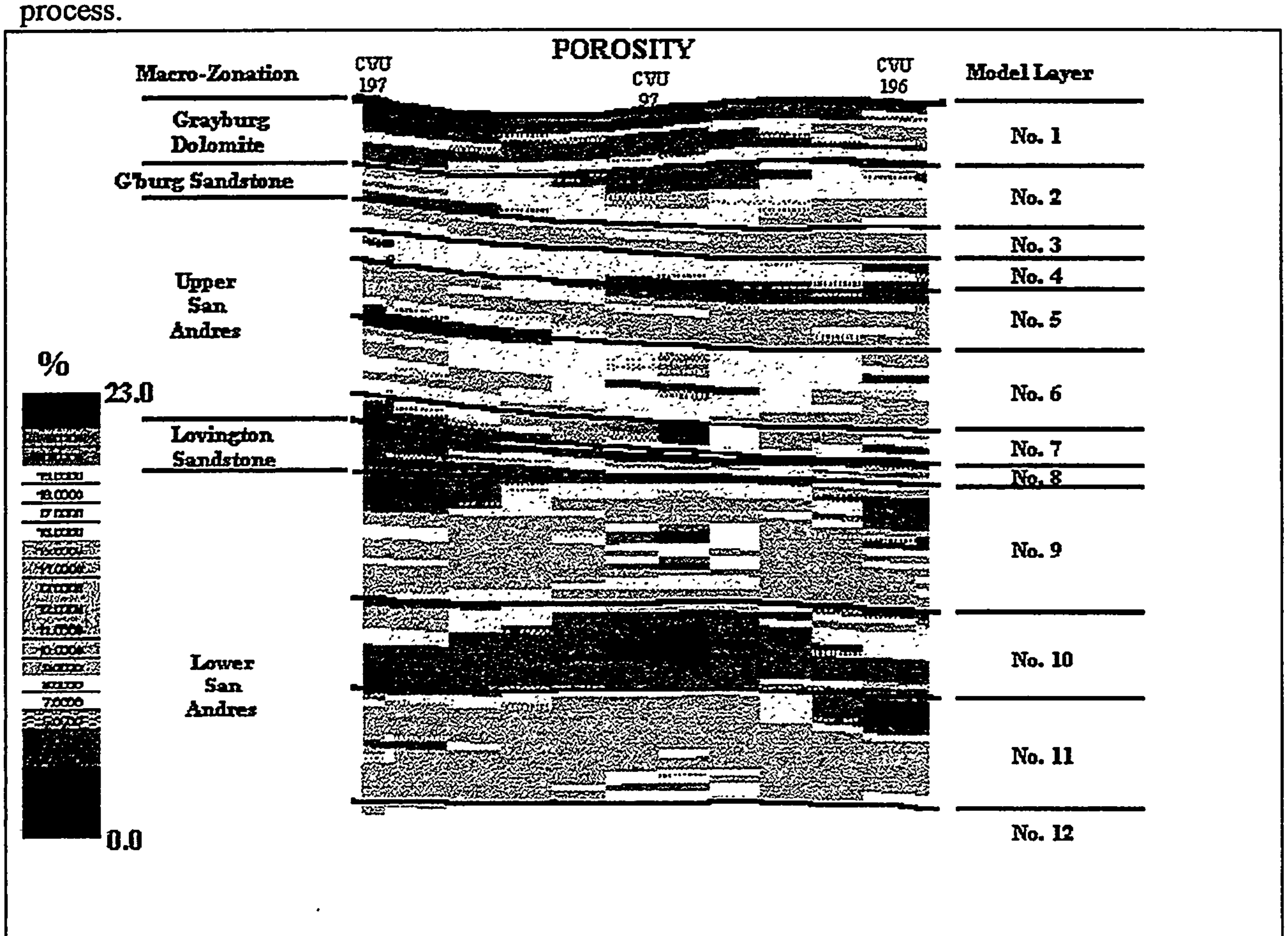
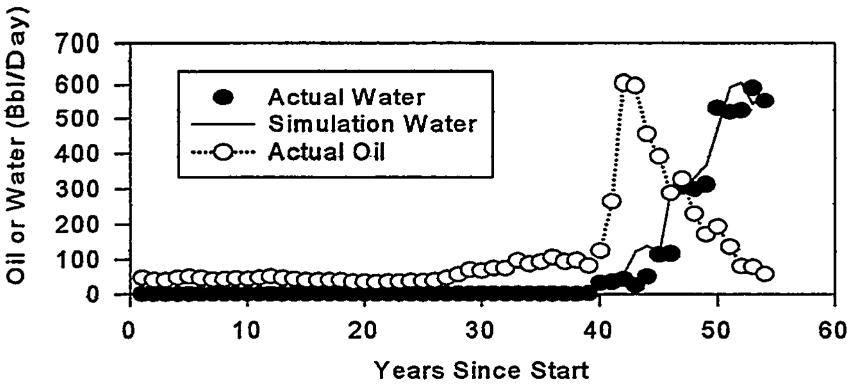


Fig. 11: East-West cross-section through Porosity model. Macro-zonation and model layer numbers identified.

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**. 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.



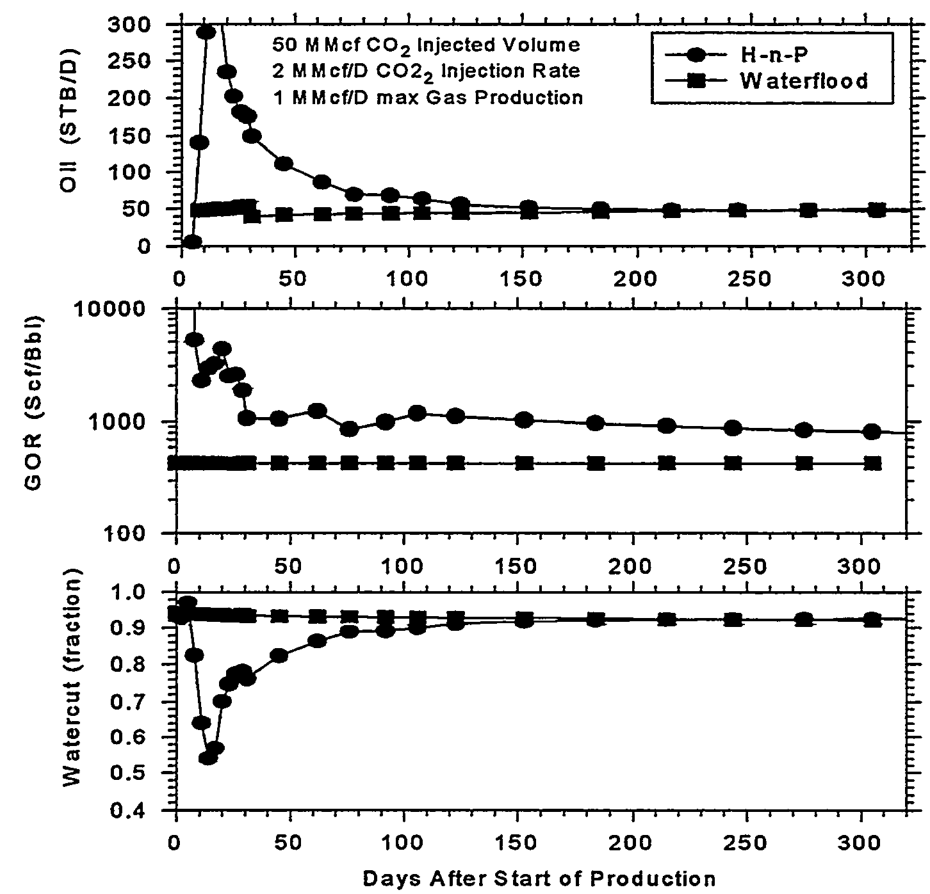


Fig. 12: Demonstration Site History Match (primary + secondary) and CO_2 H-n-P Prediction for CVU No. 97.

History Match of Field Demonstration. The need for model refinement was demonstrated by the differences between the site-specific predictions and field demonstration results (injection rates, pressures, & production). Sufficient data was gathered for a meaningful attempt at history matching. The mechanisms investigated during the parametric simulation were incorporated as warranted. The history matching of the Field Demonstration was completed during the third quarter of 1996. The pursuit of a second demonstration site is being weighed with findings developed during the history matching.

Although the predicted and actual H-n-P performance appear to be very different, a reasonably close history match was obtained with only two changes, a limitation on the gas production rate and a removal of gas hysteresis. First, the gas production during the first 65 days of production was limited to the actual gas production rate experienced in the demonstration test. Second, gas hysteresis (i.e., the gas trapping mechanism) was also eliminated. **Fig. 13** shows the history match with the limitations on the initial gas rate (and without gas trapping).

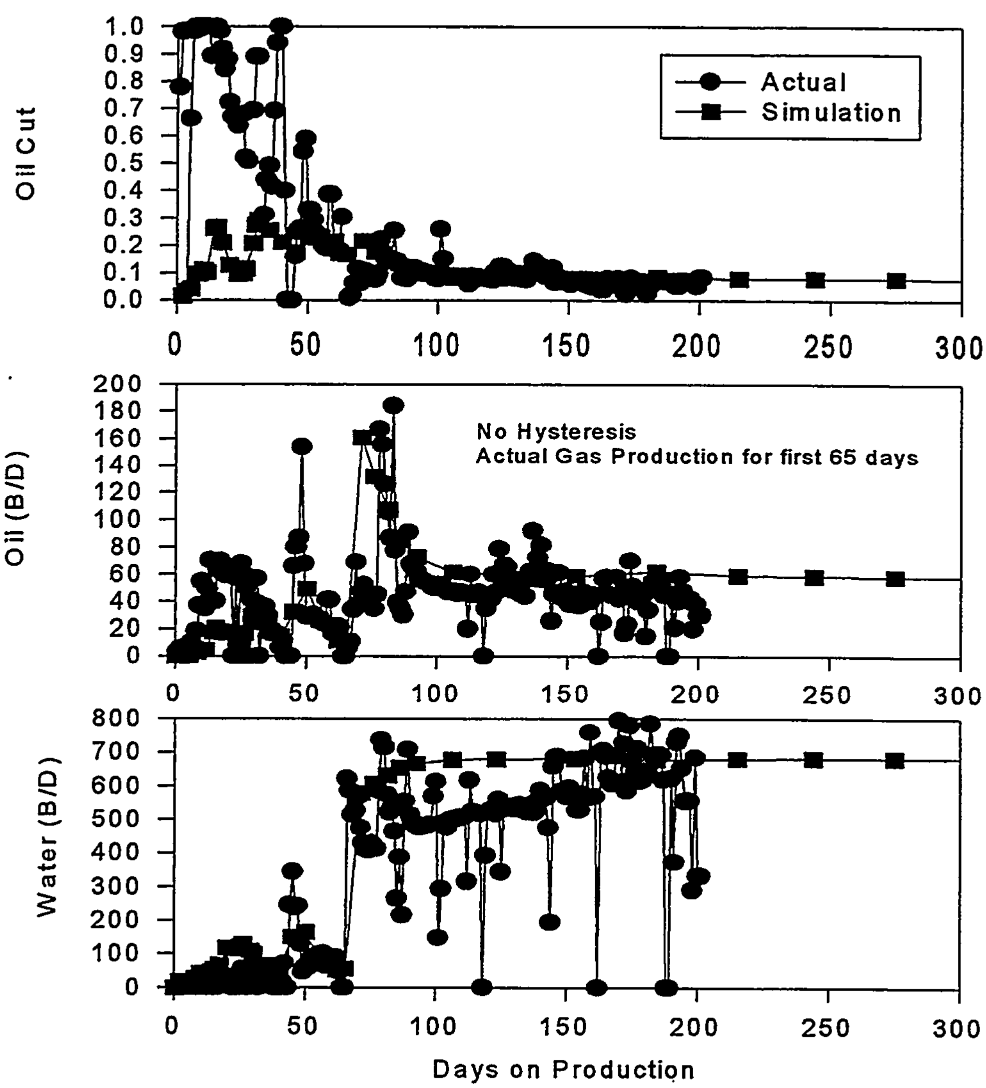


Fig. 13: History Match of CO_2 H-n-P Field Demonstration.

Comparison of Actual Performance and the Site-Specific Prediction. The two main differences between the predicted performance and the actual performance of the Huff-n-Puff were an apparent absence of gas trapping and lower than predicted production rates. The most obvious difference between the actual and predicted performance was that the total liquid (oil + water) production rates were much lower for the actual test during the period in which the well was flowing. The low production rates, which were actually less than the rates prior to the demonstration, needed to be matched in the simulation. The liquid production rates in the simulation were reduced indirectly by placing a limitation on the gas production. For the original site-specific prediction, the well was controlled in the simulation model to maintain the same liquid (oil + water) production rate after the Huff-n-Puff as before, and the gas production was not allowed to exceed 1,000 Mscf/D. There was anticipated to be an actual field limitation of 1,000 Mscf/D on gas production (the limitation on gas production in the early production period was due to disposal issues). However, in the actual field test, both the initial total liquid production rates and the gas production rates were much less than in the prediction. The gas production was initially around 1,000 Mscf/D, but it rapidly declined and became less than 100 Mscf/D before the pump was put back in the well. This was the result of flowing the well, which ultimately loaded up with liquids. The lower early liquid production rates were matched in the simulation model by limiting the simulated gas production rates to the actual gas production rates for the first 65 days the well was placed back on production.

The history match case was modified to permit the well to produce at a maximum gas rate of 1000 Mscf/D. Permitting the well to produce at a gas rate of 1,000 Mscf/D (drawing down the wellbore fluid level), increased the oil recovered during the simulated Huff-n-Puff. About 3,000 STB of incremental oil was recovered during the production period under the 1000 Mscf/D limitation scenario compared to no incremental oil when the gas production rate was reduced to match actual gas production in the demonstration site. However, the incremental oil under the 1,000 Mscf/D limitation is still only enough to compensate for deferred production during the CO_2 injection and soak phases. This modified history match case, which indicates that a high gas rate during production increases oil recovery, is consistent with previous parametric simulations that indicated incremental oil during the production phase was increased when the gas production limitation was removed. However, the rate dependency in the modified history match case was somewhat larger than in the previous parametric simulation cases. Permitting the well to produce at higher gas rates should increase the oil recovered during the Huff-n-Puff, but it is not expected to compensate for more than the oil deferred during the CO_2 injection and soak phases unless a trapped gas saturation is anticipated/developed. **Fig. 14** shows the difference between the history match simulation with the actual gas production rates and the history match case when the well was permitted to produce at a gas rate of up to 1,000 Mscf/D during the first 65 days. When the gas limitation was removed, the oil response was improved. This suggests not limiting gas production during a Huff-n-Puff.

If the well had been drawn down, higher total liquid rates would have likely been achieved. In addition, if the total liquid production rates in the actual test had been close to those in the prediction, there would probably have been a larger oil spike in production. After the pump was put back in, the liquid rate in the demonstration site did increase to pre-Huff-n-Puff levels, and the oil rate did spike up for a number of days. The oil-cut stayed above the pre-Huff-n-Puff level for a period of time after the pump was put back in.

In many Huff-n-Puffs that have been described as successful in the literature, the total liquid production rate increased although the steady oil-cut did not increase. These previous reports of increased total liquid may simply reflect a cleanup of perforations or the wellbore, whereas this demonstration utilized a wellbore that had been cleaned out several months earlier--eliminating the unknown variable.

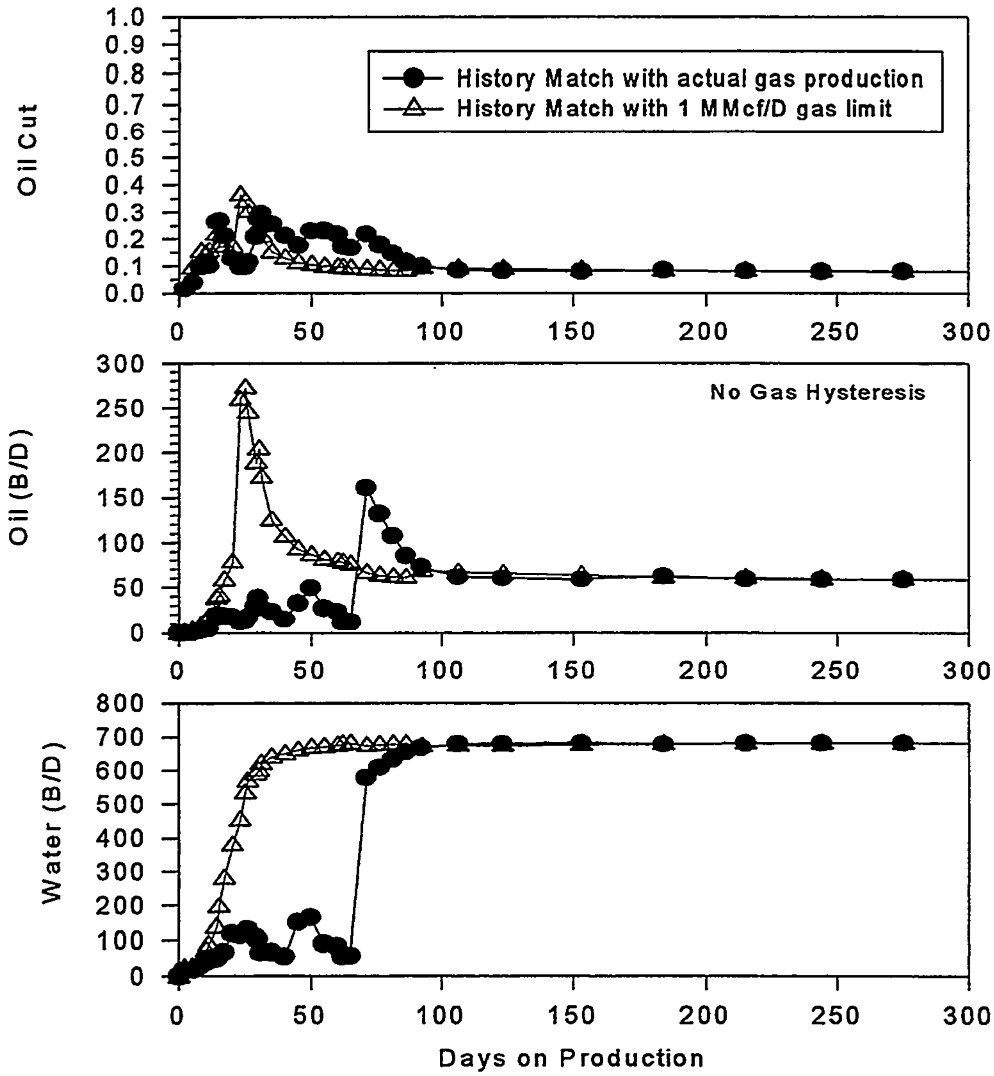


Fig. 14: Comparison of Field Demonstration History Matches while varying gas production rates.

If gas trapping occurred during the demonstration it was short-lived since nearly 100% of the injected CO_2 volume was produced. Gas trapping was the main mechanism required in theory to provide the improved oil recovery profile developed in the parametric and site specific simulations. Earlier reports detailed the need for a trapped gas saturation[13]. It is theorized that either the water production was able to dissolve the trapped gas saturation or the reservoir is not amenable to gas trapping. The simulation predictions (and history matching) do not include dissolved gas in the water fraction. Although this is known to occur on a limited basis, it could not be adequately simulated with the software which was used due to computational instabilities. (A new version of the software may have overcome these instabilities.) Additionally, it is possible that gas trapping cannot occur in this specific reservoir due to pore throat size, porosity-type, lithological characteristics, or a combination of these factors that are not currently understood.

It is interesting to note that near-wellbore gas trapping of CO_2 has been cited as one possible cause of reduced injectivity following Water-Alternating-Gas (WAG) injection methods employed in most miscible CO_2 floods. The offset East Vacuum Grayburg San Andres Unit miscible CO_2 flood, operated by Phillips, is one of the few Permian Basin CO_2 floods that has not experienced any appreciable reduction in injectivity during 11 years of WAG operations even though many of the other shallow shelf carbonate reservoirs experience 30 to 50 percent reductions in water injectivity following the introduction of CO_2 to the reservoirs. If it can be inferred that reduced injectivity in WAG operations is related to gas trapping, then Vacuum field is not a good candidate for further testing of the Huff-n-Puff technology. Oxy has been experimenting with Huff-n-Puff technology in the Welch field of West Texas. Oxy's Huff-n-Puff results have been favorable enough to expand their program. An offset miscible CO_2 flood within the Welch field experienced reduced injectivity in WAG operations. This further suggests that the technology should be applied to another reservoir that has documented WAG injectivity reductions. This option is being pursued. The Huff-n-Puff technology might become a valuable indicator of potential injection rates when designing a miscible CO_2 flood. Injectivity is one of the main parameters affecting the economics of these large scale projects. The failure of the Huff-n-Puff might indicate favorable expectations of injection, whereas a positive response may suggest injectivity reductions--thus the need for the parallel implementation of the Huff-n-Puff technology.

The oilcut in the actual Huff-n-Puff was very high, better than 0.90 for a period of time. The predicted oilcut did not reach such high levels. In addition, the high oilcut could not be achieved in the history match efforts. Although the oilcut was very high, the actual oil rate was quite small in this period--as was water production. The capability of accurately measuring these small volumes may have an influence on the calculated oilcut in the initial production period. It is also possible that water relative permeability curve hysteresis may be required to limit the water production in the simulation. This option is not available in the commercial simulator used. If the total liquid production rate in the actual test during the flowing period had been close to that in the prediction, there would have been a large oil spike in production. After the pump was put back in, the liquid rate in the demonstration site did increase to pre-Huff-n-Puff levels, and the oil rate did spike up for a few days. The oilcut stayed above the pre-Huff-n-Puff level for a period of time after the pump was put back in.

The simulation also suggests that an error in the measured gas production rate may have occurred shortly after the pump was put back in. The metered volumes plateaued after the 100th day rather than continuing to decline. Metered gas volumes from the demonstration site also suggest recovery was 40-50% higher than the volume injected. **Fig. 15** compares the measured and simulated gas production for the history match.

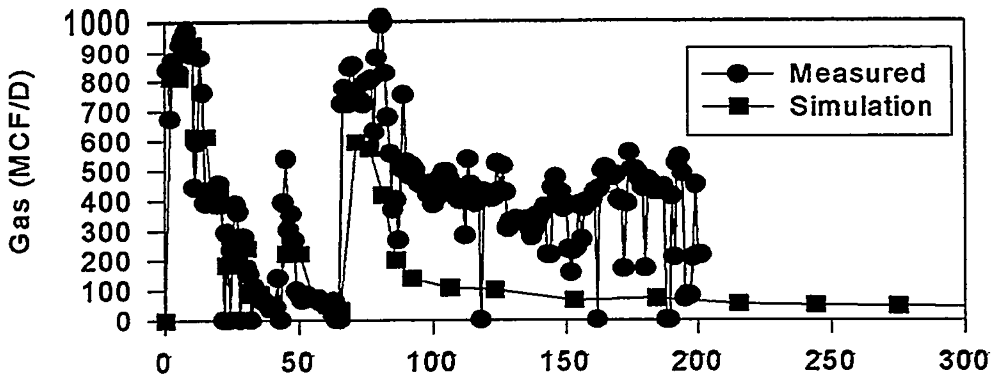


Fig. 15: Actual vs. Simulated Gas Production from Field Demonstration.

Fig. 16 compares the site-specific prediction with the history match case in which the gas production rate was permitted to reach 1000 Mcf/D. The site-specific forecast also had a 1000 Mcf/D gas production limitation. The main difference between these two cases is that the forecast had gas trapping (i.e., gas hysteresis) while the history match case did not. The absence of the residual gas saturation delays and reduces the predicted oil production.

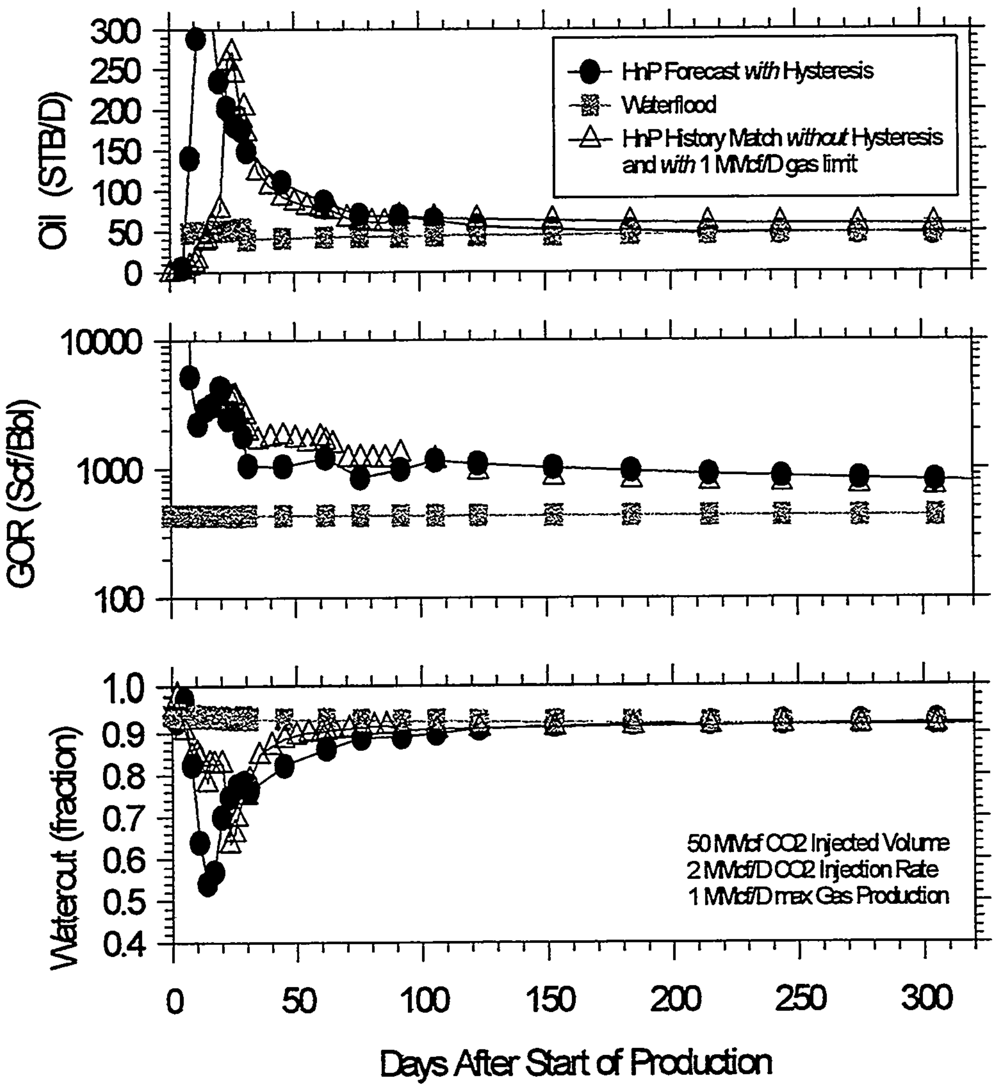


Fig. 16: Comparison of Site-specific forecast and Field Demonstration History Match after removing the gas rate restrictions.

Summary. The history matching efforts validate the decision to not attempt any more Huff-n-Puffs at CVU. In addition to requirements for a trapped gas saturation, there also appears to be a "rate" requirement for a successful Huff-n-Puff which cannot be tolerated due to disposal limitations at CVU. If the total liquid production rate during the H-n-P cannot be maintained at the same level (or least a high fraction) of the pre-H-n-P level, then the H-n-P will not be successful because the oil rate will be too small (even though the oil cut might be improved). If this CVU well is typical, a successful H-n-P may not be possible for a well which must be converted from pumping status to flowing status and back again. The liquid production rate during the flowing period would be too low. This work suggests that improved rates may be possible if higher gas volume production equipment can be utilized.

The simulation Input and Output Datasets have been provided in **Appendix "B"** for the readers review.

COST & ECONOMIC CONSIDERATIONS

The actual costs associated with the field demonstration components of the project are included in **Table 2** under the heading, *No. 1 (Pumped)*. There were a number of non-recurring charges identified that would not be included if a second site was chosen at CVU for another demonstration. Additionally, the volume of CO_2 would not be as large; reducing pump time. The soak period would also be scaled back somewhat. This second option is depicted in **Table 2** as *No. 2 (Pumped)*. The cost of a second site at CVU would be about half the cost of the first site. As originally hypothesized, the largest benefit of this technology would come from coupling it to a miscible CO_2 flood; having pipeline CO_2 available as the project was implemented and expanded. This last scenario is included in **Table 2** as *No. 2 (Piped)*. The availability of pipeline CO_2 makes a significant impact on the cost of the demonstration. The piped CO_2 scenario would cost about one-quarter of the first demonstration.

Table 2: Field Demonstration Costs

($M)

DEMONSTRATION	No. 1 (Pumped)	No. 2 (Pumped)	No. 2 (Piped)
Deferred Production, Days	43	20	20
Test Separator	34.2	0	0
CO2 Commodity/ Transport/Pump	142.3	79	19
Wireline	5.9	6	6
Downhole*	19.5	15	15
Surface**	42.8	20	20
New Tbg.	15.6	0	0
In-Line Heater	6	0	0
Misc.	17.8	10	10
TOTAL:	284.1	130	70
DOE Share (45%)	127.8	58.5	31.5
CVU Share (55%)	156.2	71.5	38.5

* Pulling Unit, etc.
**Contract labor, welding, transport, etc.

Table 3 shows some simple relationships depicting the basic economics of the H-n-P demonstration along with the two options previously discussed. The same naming convention is applied. In addition to some non-recurring items the field demonstration costs were heavily influenced by the cost of delivering and pumping the CO_2. As can be seen in **Table 3**, the planned CO_2 volume would not likely be as large for a second demonstration. This directly impacts the amount of deferred production.

The project becomes more attractive if pipeline CO_2 is available. Assuming an $18.00/STB sales price for crude oil, the necessary volume of recovery to reach a pseudo-breakeven point is calculated. The cost reductions available for the *No. 2 (Piped)* case begin to look encouraging. The CO_2 utilization in this later case looks reasonable at 6.4 Mscf/STB--similar to miscible CO_2 flooding cases. The recovery for the *No. 2 (Piped)* case are similar to expectations derived from the compositional simulations when a trapped gas saturation develops in the near wellbore vicinity.

Table 3: Field Demonstration Economics

[back of the napkin]

DEMONSTRATION	No. 1 (Pumped)	No. 2 (Pumped)	No. 2 (Piped)
CO2 Vol., MMscf	50	25	25
CO2 Cost, $/Mscf	2.85	3.16	0.76
Deferred Production, STB	2924	1360	1360
TOTAL Cost, $M	284.1	130	70
Equiv. Bbl's @ $18/STB	15800	7200	3900
Breakeven Utilization, Mcf/STB	3.2	3.5	6.4

Additional benefits that are not accounted for in this simplistic review were noted earlier. First, even though recoveries in this demonstration accounted for only the deferred production, there were reduced electrical requirements during the injection, soak and flow period. Secondly, there were reduced water handling requirements for an extended period of time. These benefits, coupled with the potential to recover additional oil suggest further investigation is warranted if the technology is applied to a reservoir amenable to gas trapping.

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 CO_2 into the reservoir along with stress field changes. A base survey was made prior to the introduction of CO_2. A follow-up survey was then obtained immediately prior to the end of the CO_2 soak period. The information gained through this seismic demonstration complements the subject project. As yet, the seismic information has not provided the necessary data for any refinements to the reservoir model (layering, flow capacity, fracture orientation, etc.) and fluid characterization (saturations, fluid flow; etc.). Their work continues. Their consideration of the CVU as a demonstration site was made possible by the fact that the accumulation of data from this CO_2 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 complete their initial phase of study during 1997.

TECHNOLOGY TRANSFER

Technology transfer activities during the 1996 period consisted of updates of project progress and findings through newsletters, publications/presentations, Joint Project Advisory Team Meetings, and information posted on an Internet site.

The Petroleum Recovery Research Center continues to provide updates on the project in its quarterly newsletter. In addition, the Petroleum Technology Transfer Counsel, a joint venture between the Independent Producers Association of America (IPAA) and DOE is providing complete Quarterly and Annual Technical Reports on an Industry Bulletin Board called GO-TECH. This provides a timely dissemination of information to interested parties.

Abstracts were accepted and manuscripts presented at the Society of Petroleum Engineers' (SPE) Permian Basin Oil and Gas Recovery Conference (March 1996). The technical paper was published in the conference's proceedings (SPE No. 35223 - <u>CO_2 Huff-n-Puff: Initial Results From a Waterflooded SSC Reservoir</u>, S. C. Wehner, Texaco E&P Inc., J. Prieditis, Texaco E&P Technology Div., 03/27-29/96).

The Joint Project Advisory Team (JPAT) met during the month of June. This group is composed of the 21 partners holding ownership in the Central Vacuum Unit, TEPI principal investigators, the New Mexico Petroleum Recovery Institute and the DOE. The JPAT representatives were brought up-to-date on the field demonstration and discussed related issues.

Two industry presentations were conducted during the year. The first presentation was in Roswell, New Mexico on August 22-23, 1996. This first presentation was a workshop called Integration of Advanced Geoscience & Engineering Techniques of Class II DOE projects. The second presentation was at the New Mexico Petroleum Recovery Research Center in Socorro, New Mexico on October 23-24, 1996. This second presentation was part of a CO_2 Oil Recovery Forum co-sponsored by the Petroleum Technology Transfer Counsel.

CONCLUSIONS

A successful demonstration of the CO_2 Huff-n-Puff process could have wide application. The proposed technology promises several advantages. It is hoped that the CO_2 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 CO_2 projects. Although it still has promise for other fields, the Huff-n-Puff process does not appear to be viable at CVU, and a decision has been made to not attempt any additional Huff-n-Puffs at CVU.

Simulation of the Huff-n-Puff process was found to be useful, and it was found that most aspects of the CO_2 H-n-P process could be adequately simulated with existing commercial software. The simulation efforts involved in history matching the CVU Huff-n-Puff support the conclusion to not attempt any additional Huff-n-Puffs at CVU. All the simulation efforts to date, including the initial parametric studies as well as the history matches, indicated that a high trapped gas saturation was required for a successful Huff-n-Puff. Actual performance of the Huff-n-Puff suggests an absence of a large trapped gas saturation.

By far the most important finding to date is that the first field demonstration has not performed as expected. Hydrocarbon recoveries appear to be equivalent to the deferred production of the injection and soak period. In addition, it is apparent that 100% of the injected CO_2 will be recovered. These results indicate that a large trapped gas saturation did not exist, and, as previously stated, a large trapped gas saturation is necessary for a successful Huff-n-Puff. It is theorized either that the water production was able to dissolve the trapped gas saturation or that the reservoir is not amenable to gas trapping. Gas trapping may not occur in this specific reservoir due to pore throat size, porosity-type, lithological characteristics, or a combination of these factors that are not currently understood.

It is interesting to note that near-wellbore gas trapping of CO_2 has been cited as one possible cause of reduced injectivity following Water-Alternating-Gas (WAG) injection methods employed in many miscible CO_2 floods. The offset East Vacuum Grayburg San Andres Unit miscible CO_2 flood, operated by Phillips, is one of the few Permian Basin CO_2 floods that has not experienced any appreciable reduction in injectivity during 12 years of WAG operations even though many of the other shallow shelf carbonate reservoirs experience 30 to 50 percent reductions in water injectivity following the introduction of CO_2 to the reservoirs. If it can be inferred that reduced injectivity in WAG operations is related to gas trapping, then Vacuum field is not a good candidate for further testing of the Huff-n-Puff technology. Oxy has been experimenting with Huff-n-Puff technology in the Welch field of West Texas. Oxy's Huff-n-Puff results have been favorable enough to expand their program. An offset miscible CO_2 flood within the Welch field showed reduced injectivity in WAG operations. This further suggests that the technology should be applied to another reservoir that has documented WAG injectivity reductions to validate the hypothesis. The Huff-n-Puff technology might become a valuable indicator of potential injection rates when designing a miscible CO_2 flood. Injectivity is one of the main parameters affecting the economics of these large scale projects. The failure of the Huff-n-Puff might indicate favorable expectations of injection, whereas a positive response may suggest injectivity reductions--thus the need for the parallel implementation of the Huff-n-Puff technology.

In addition to requirements for a trapped gas saturation, there appears a "rate" requirement for a successful H-n-P which may not be possible due to disposal limitations at CVU. The gas production rate was initially limited to somewhat less than 1000 Mscf/D. The rate was then choked down even further and ultimately declined to about 100 Mscf/D after liquid build-up in the wellbore. The total liquid production from the well also decreased during the period when the gas production was reduced. Modifications of the history match as well as previous parametric simulations indicate that increasing the gas production rate will also increase the total liquid production rate, which, in turn, will increase the incremental oil. If the total liquid production rate during the Huff-n-Puff cannot be maintained at the same level (or least a high fraction) of the pre-Huff-n-Puff level, then the Huff-n-Puff will not be successful because the oil rate will be too small (even though the oil cut might be improved). If this CVU well is typical, a successful Huff-n-Puff may not be possible for a well which must be converted from pumping status to flowing status and back again. The liquid production rate during the flowing period would be too low. This work suggests that improved oil production rates may be possible if higher gas volume production equipment can be utilized.

There are additional benefits that are not accounted for in study. First, even though recoveries in this demonstration accounted for only the deferred production, there were reduced electrical requirements during the injection, soak and flow period. Secondly, there were reduced water handling requirements for an extended period of time--suggesting that even a small amount of CO_2 has a significant impact on water relative permeability. These benefits, coupled with the potential to recover additional oil suggest further investigation is warranted if the technology is applied to a reservoir amiable to gas trapping.

Pursuit of a second demonstration site, amenable to gas trapping is underway. Following a successful demonstration, the development of guidelines for the cost-effective selection of candidate sites, along with estimation of recovery potential, will be pursued.

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*** APPENDIX ***

"A"	Field Demonstration Historical Performance Data
"B"	VIP-COMP Simulation Input/Output Data

*** APPENDIX "A" ***

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.
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	—	—	—	—	—	1.88	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	—	—
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	—	—

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.
12/15/95	—	—	—	—	—	—	823	—	0	—	—
12/16/95	—	—	—	—	—	—	831	—	0	—	—
12/17/95	—	—	—	—	—	—	846	—	0	—	—
12/18/95	—	—	—	—	—	—	868	—	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	23	9000	—	607	17	258	94.8%	0.19
1/7/96	49	0	594	38	9556	—	631	17	346	93.7%	0.20
1/8/96	70	8	884	56	10384	—	645	18	521	93.7%	0.22
1/9/96			763	48	11099	—	563	18	382	93.7%	0.23
1/10/96	40	0	393	25	11467	—	593	13	237	93.7%	0.24
1/11/96	63	1	414	26	11855	—	613	14	271	93.7%	0.25
1/12/96	70	6	434	28	12261	—	580	14	293	93.7%	0.26
1/13/96	60	11	392	25	12628	—	589	14	267	93.7%	0.26
1/14/96	59	8	388	25	12992	—	590	15	261	93.7%	0.27
1/15/96	63	24	455	29	13418	—	554	14	315	93.7%	0.28
1/16/96	65	32	388	39	13767	—	537	14	291	89.9%	0.29
1/17/96	—	—	—	—	13767	—	—	14	0	89.9%	0.29
1/18/96	57	32	293	30	14030	—	531	14	236	89.9%	0.29
1/19/96	—	—	—	—	14030	—	—	14	0	89.9%	0.29
1/20/96	68	32	238	24	14244	—	574	14	219	89.9%	0.30
1/21/96	60	55	388	39	14593	—	474	17	309	89.9%	0.30
1/22/96	50	48	363	37	14919	—	450	17	280	89.9%	0.31
1/23/96	—	—	—	—	14919	—	—	17	0	89.9%	0.31
1/24/96	41	18	278	34	15163	—	442	14	198	87.8%	0.32
1/25/96	57	7	176	22	15318	—	439	14	152	87.8%	0.32
1/26/96	57	7	152	19	15451	—	432	14.5	140	87.8%	0.32
1/27/96	—	—	—	—	15451	—	414	14.5	0	87.8%	0.32
1/28/96	24	53	110	13	15548	—	414	14.5	132	87.8%	0.32
1/29/96	36	46	91	11	15628	—	411	14.5	128	87.8%	0.33
1/30/96	29	30	86	11	15703	—	421	14.5	102	87.8%	0.33
1/31/96	17	24	66	8	15761	—	416	17	74	87.8%	0.33
2/1/96	18	8	62	8	15815	—	401	20	57	87.8%	0.33
2/2/96	16	1	54	7	15863	—	415	14	44	87.8%	0.33
2/3/96	16	0	38	5	15896	—	379	14	35	87.8%	0.33
2/4/96	6	0	40	5	15931	—	200	14	26	87.8%	0.33
2/5/96	12	18	44	5	15970	—	350	18	52	87.8%	0.33
2/6/96	0	72	139	17	16092	—	352	18	142	87.8%	0.34
2/7/96	—	—	—	—	16092	—	—	18	0	87.8%	0.34
2/8/96	0	247	393	48	16437	—	226	26	444	87.8%	0.34
2/9/96	66	344	539	66	16910	—	143	26	680	87.8%	0.35
2/10/96	80	240	302	37	17175	—	138	32	471	87.8%	0.36
2/11/96	87	244	355	48	17482	—	103	26	509	86.5%	0.36
2/12/96	154	129	267	36	17713	—	59	32	417	86.5%	0.37
2/13/96	68	47	97	13	17797	—	55	32	164	86.5%	0.37
2/14/96	29	59	88	12	17873	—	64	20	132	86.5%	0.37
2/15/96	29	59	68	9	17932	—	65	20	122	86.5%	0.37
2/16/96	29	70	72	10	17994	—	90	20	135	86.5%	0.37
2/17/96	30	92	83	11	18066	—	51	20	164	86.5%	0.38
2/18/96	28	93	76	10	18132	—	67	20	159	86.5%	0.38
2/19/96	26	93	75	10	18197	—	143	20	157	86.5%	0.38
2/20/96	25	100	72	10	18259	—	164	20	161	86.5%	0.38
2/21/96	24	102	72	10	18321	—	54	26	162	86.5%	0.38
2/22/96	41	65	61	8	18374	—	110	26	137	86.5%	0.38
2/23/96	41	65	61	8	18427	—	110	32	137	86.5%	0.38
2/24/96	17	74	49	7	18469	—	55	32	116	86.5%	0.38
2/25/96	19	86	51	7	18513	—	55	32	131	88.5%	0.39
2/26/96	20	90	55	7	18561	—	65	32	138	86.5%	0.39
2/27/96	21	48	64	9	18616	—	—	—	101	86.5%	0.39

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.
2/28/96	0	0	0	0	18616	—	—	—	0	86.5%	0.39
2/29/96	0	0	0	0	18616	—	—	—	0	86.5%	0.39
3/1/96	6	621	725	88	19243	—	—	—	990	86.5%	0.40
3/2/96	11	587	777	105	19916	—	—	—	987	86.5%	0.41
3/3/96	34	514	726	98	20543	—	—	—	911	86.5%	0.43
3/4/96	69	528	847	114	21276	—	—	—	1021	86.5%	0.44
3/5/96	38	567	858	127	22007	—	—	—	1034	85.2%	0.46
3/6/96	47	475	754	112	22650	—	—	—	899	85.2%	0.47
3/7/96	52	430	745	110	23284	—	—	—	855	85.2%	0.49
3/8/96	42	411	728	108	23905	—	—	—	817	85.2%	0.50
3/9/96	43	408	726	107	24523	—	—	—	814	85.2%	0.51
3/10/96	45	430	798	118	25203	—	—	—	874	85.2%	0.53
3/11/96	35	421	801	119	25886	—	—	—	857	85.2%	0.54
3/12/96	45	413	810	120	26576	—	—	—	863	85.2%	0.55
3/13/96	167	587	631	93	27113	—	—	—	1070	85.2%	0.56
3/14/96	156	737	883	119	27878	—	—	—	1335	86.6%	0.58
3/15/96	126	715	1000	134	28744	—	—	—	1341	86.6%	0.60
3/16/96	106	576	1000	134	29609	—	—	—	1182	86.6%	0.62
3/17/96	87	522	829	111	30327	—	—	—	1024	86.6%	0.63
3/18/96	184	536	680	91	30916	—	—	—	1060	86.6%	0.64
3/19/96	78	465	557	75	31398	—	—	—	822	86.6%	0.65
3/20/96	39	266	370	50	31718	—	—	—	490	86.6%	0.66
3/21/96	35	387	402	54	32066	—	—	—	623	86.6%	0.67
3/22/96	30	216	267	28	32305	—	—	—	380	89.6%	0.67
3/23/96	47	554	508	53	32760	—	—	—	855	89.6%	0.68
3/24/96	91	707	756	79	33437	—	—	—	1176	89.6%	0.70
3/25/96	68	515	529	78	33888	—	—	—	848	85.2%	0.71
3/26/96	65	488	483	71	34300	—	—	—	795	85.2%	0.71
3/27/96	62	488	516	76	34740	—	—	—	808	85.2%	0.72
3/28/96	56	478	502	89	35153	—	—	—	785	82.2%	0.73
3/29/96	56	478	469	83	35538	—	—	—	769	82.2%	0.74
3/30/96	55	480	455	81	35913	—	—	—	763	82.2%	0.75
3/31/96	54	482	450	80	36283	—	—	—	761	82.2%	0.76
4/1/96	53	483	445	79	36649	—	—	—	759	82.2%	0.76
4/2/96	51	486	422	75	36996	—	—	—	748	82.2%	0.77
4/3/96	50	570	456	81	37371	—	—	—	848	82.2%	0.78
4/4/96	52	613	388	70	37689	—	—	—	859	81.9%	0.79
4/5/96	52	148	418	75	38031	—	—	—	409	81.9%	0.79
4/6/96	52	294	415	75	38371	—	—	—	554	81.9%	0.80
4/7/96	50	489	474	86	38760	—	—	—	776	81.9%	0.81
4/8/96	47	475	494	89	39165	—	—	—	769	81.9%	0.82
4/9/96	48	497	494	91	39567	—	—	—	792	81.5%	0.82
4/10/96	48	501	471	87	39951	—	—	—	785	81.5%	0.83
4/11/96	47	501	423	81	40293	—	—	—	760	80.8%	0.84
4/12/96	46	502	447	86	40654	—	—	—	772	80.8%	0.85
4/13/96	47	508	409	79	40984	—	—	—	760	80.8%	0.85
4/14/96	47	505	400	77	41308	—	—	—	752	80.8%	0.86
4/15/96	46	508	415	72	41650	—	—	—	762	82.6%	0.87
4/16/96	20	316	283	49	41884	—	—	—	478	82.6%	0.87
4/17/96	60	617	537	94	42327	—	—	—	946	82.6%	0.88
4/18/96	45	524	452	79	42700	—	—	—	795	82.6%	0.89
4/19/96	45	519	431	75	43056	—	—	—	780	82.6%	0.90
4/20/96	47	520	390	68	43378	—	—	—	762	82.6%	0.90
4/21/96	45	517	428	75	43732	—	—	—	776	82.6%	0.91
4/22/96	—	—	—	—	43732	—	—	—	0	82.6%	0.91
4/23/96	35	392	428	75	44085	—	—	—	641	82.6%	0.92
4/24/96	43	521	411	72	44424	—	—	—	770	82.6%	0.93
4/25/96	42	528	422	78	44769	—	—	—	781	81.6%	0.93
4/26/96	60	524	407	75	45101	—	—	—	788	81.6%	0.94
4/27/96	47	516	412	76	45437	—	—	—	769	81.6%	0.95
4/28/96	79	560	524	96	45864	—	—	—	901	81.6%	0.96
4/29/96	49	344	431	79	46216	—	—	—	609	81.6%	0.96
4/30/96	67	534	515	101	46630	—	—	—	859	80.4%	0.97
5/1/96	65	540	427	84	46973	—	—	—	819	80.4%	0.98
5/2/96	53	535	308	61	47221	—	—	—	742	80.3%	0.98
5/3/96	48	539	329	65	47485	—	—	—	752	80.3%	0.99
5/4/96	56	532	332	65	47751	—	—	—	754	80.3%	0.99
5/5/96	56	532	338	67	48022	—	—	—	757	80.3%	1.00
5/6/96	46	546	333	69	48286	—	—	—	759	79.2%	1.01
5/7/96	54	536	334	70	48551	—	—	—	757	79.2%	1.01
5/8/96	44	536	327	68	48809	—	—	—	743	79.2%	1.02
5/9/96	58	523	335	70	49075	—	—	—	749	79.2%	1.02
5/10/96	62	535	310	64	49320	—	—	—	752	79.2%	1.03
5/11/96	92	546	280	58	49542	—	—	—	778	79.2%	1.03
5/12/96	57	522	305	63	49783	—	—	—	731	79.2%	1.04

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.
5/13/96	72	555	347	72	50058	—	—	—	801	79.2%	1.04
5/14/96	82	587	344	72	50330	—	—	—	841	79.2%	1.05
5/15/96	56	562	360	75	50615	—	—	—	798	79.2%	1.05
5/16/96	63	565	378	79	50915	—	—	—	817	79.2%	1.06
5/17/96	58	476	218	45	51088	—	—	—	643	79.2%	1.06
5/18/96	26	195	218	45	51261	—	—	—	330	79.2%	1.07
5/19/96	46	659	442	92	51611	—	—	—	926	79.2%	1.08
5/20/96	61	687	475	99	51987	—	—	—	986	79.2%	1.08
5/21/96	61	687	407	85	52309	—	—	—	951	79.2%	1.09
5/22/96	43	585	427	89	52647	—	—	—	842	79.2%	1.10
5/23/96	48	579	372	77	52942	—	—	—	813	79.2%	1.10
5/24/96	41	570	387	81	53248	—	—	—	804	79.2%	1.11
5/25/96	38	596	237	49	53435	—	—	—	752	79.2%	1.11
5/26/96	46	574	157	35	53557	—	—	—	699	77.5%	1.12
5/27/96	44	565	231	52	53736	—	—	—	725	77.5%	1.12
5/28/96	37	530	240	54	53922	—	—	—	687	77.5%	1.12
5/29/96	37	530	384	86	54220	—	—	—	759	77.5%	1.13
5/30/96	47	578	269	61	54428	—	—	—	760	77.5%	1.13
5/31/96	41	683	376	85	54720	—	—	—	912	77.5%	1.14
6/1/96	45	565	394	89	55025	—	—	—	807	77.5%	1.15
6/2/96	40	760	391	88	55328	—	—	—	896	77.5%	1.15
6/3/96	44	568	400	90	55638	—	—	—	812	77.5%	1.16
6/4/96	45	570	426	96	55968	—	—	—	828	77.5%	1.17
6/5/96	—	—	—	—	55968	—	—	—	0	77.5%	1.17
6/6/96	25	699	437	98	56307	—	—	—	943	77.5%	1.17
6/7/96	57	705	498	112	56693	—	—	—	1011	77.5%	1.18
6/8/96	58	688	508	114	57087	—	—	—	1000	77.5%	1.19
6/9/96	46	626	482	108	57460	—	—	—	913	77.5%	1.20
6/10/96	45	608	476	107	57829	—	—	—	891	77.5%	1.20
6/11/96	45	608	476	107	58198	—	—	—	891	77.5%	1.21
6/12/96	58	691	484	109	58573	—	—	—	891	77.5%	1.22
6/13/96	42	796	402	90	58885	—	—	—	1039	77.5%	1.23
6/14/96	47	613	394	89	59190	—	—	—	857	77.5%	1.23
6/15/96	17	727	170	43	59318	—	—	—	829	75.0%	1.24
6/16/96	23	587	390	98	59610	—	—	—	805	75.0%	1.24
6/17/96	70	780	560	140	60030	—	—	—	1130	75.0%	1.25
6/18/96	51	676	503	126	60407	—	—	—	979	75.0%	1.26
6/19/96	46	631	503	126	60785	—	—	—	929	75.0%	1.27
6/20/96	40	711	493	123	61154	—	—	—	998	75.0%	1.27
6/21/96	44	615	469	117	61506	—	—	—	894	75.0%	1.28
6/22/96	45	619	443	111	61838	—	—	—	886	75.0%	1.29
6/23/96	15	630	172	43	61967	—	—	—	731	75.0%	1.29
6/24/96	34	647	468	117	62318	—	—	—	915	75.0%	1.30
6/25/96	49	786	460	115	62663	—	—	—	1065	75.0%	1.31
6/26/96	55	693	431	108	62987	—	—	—	964	75.0%	1.31
6/27/96	55	693	431	119	63299	—	—	—	964	72.5%	1.32
6/28/96	55	693	431	119	63611	—	—	—	964	72.5%	1.33
6/29/96	55	693	431	119	63924	—	—	—	964	72.5%	1.33
6/30/96	45	619	443	122	64245	—	—	—	886	72.5%	1.34
7/1/96	—	—	—	—	64245	—	—	—	0	72.5%	1.34
7/2/96	—	—	—	—	64245	—	—	—	0	72.5%	1.34
7/3/96	46	624	413	114	64545	—	—	—	877	72.5%	1.34
7/4/96	21	374	210	58	64697	—	—	—	500	72.5%	1.35
7/5/96	40	731	525	144	65077	—	—	—	1034	72.5%	1.36
7/6/96	58	749	543	149	65471	—	—	—	1079	72.5%	1.36
7/7/96	48	654	490	135	65826	—	—	—	947	72.5%	1.37
7/8/96	41	557	72	20	65879	—	—	—	634	72.5%	1.37
7/9/96	41	559	83	23	65939	—	—	—	642	72.5%	1.37
7/10/96	42	556	81	22	65997	—	—	—	639	72.5%	1.37
7/11/96	20	291	206	59	66144	—	—	—	414	71.3%	1.38
7/12/96	38	684	452	130	66467	—	—	—	948	71.3%	1.38
7/13/96	30	333	217	62	66621	—	—	—	472	71.3%	1.39
7/14/96	30	333	217	62	66776	—	—	—	472	71.3%	1.39
7/15/96				0	66776	—	—	—	0	69.0%	1.39
7/16/96	55	600	82.5	26	66833	—	—	—	696	69.0%	1.39
7/17/96	55	600	82.5	26	66890	—	—	—	696	69.0%	1.39
7/18/96	55	600	82.5	26	66947	—	—	—	696	69.0%	1.39
7/19/96	55	600	82.5	26	67004	—	—	—	696	69.0%	1.40
7/20/96	55	600	82.5	27	67060	—	—	—	696	67.8%	1.40
7/21/96	55	600	82.5	27	67116	—	—	—	696	67.8%	1.40
7/22/96	55	600	82.5	27	67172	—	—	—	696	67.8%	1.40
7/23/96	55	600	82.5	27	67228	—	—	—	696	67.8%	1.40
7/24/96	55	600	82.5	27	67283	—	—	—	696	67.8%	1.40
7/25/96	55	600	82.5	27	67339	—	—	—	696	67.8%	1.40
7/26/96	55	600	82.5	27	67395	—	—	—	696	67.8%	1.40

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.
7/27/96	55	600	82.5	27	67451	—	—	—	696	67.8%	1.41
7/28/96	55	600	82.5	27	67507	—	—	—	696	67.8%	1.41
7/29/96	55	600	82.5	27	67563	—	—	—	696	67.8%	1.41
7/30/96	55	600	82.5	27	67619	—	—	—	696	67.8%	1.41
7/31/96	55	600	82.5	27	67675	—	—	—	696	67.8%	1.41
8/1/96	55	600	82.5	33	67725	—	—	—	696	60.0%	1.41
8/2/96	55	600	82.5	33	67774	—	—	—	696	60.0%	1.41
8/3/96	55	600	82.5	33	67824	—	—	—	696	60.0%	1.41
8/4/96	55	600	82.5	33	67873	—	—	—	696	60.0%	1.41
8/5/96	55	600	82.5	33	67923	—	—	—	696	60.0%	1.42
8/6/96	55	600	82.5	33	67972	—	—	—	696	60.0%	1.42
8/7/96	55	600	82.5	33	68022	—	—	—	696	60.0%	1.42
8/8/96	55	600	82.5	33	68071	—	—	—	696	60.0%	1.42
8/9/96	55	600	82.5	33	68121	—	—	—	696	60.0%	1.42
8/10/96	55	600	82.5	33	68170	—	—	—	696	60.0%	1.42
8/11/96	55	600	82.5	33	68220	—	—	—	696	60.0%	1.42
8/12/96	55	600	82.5	33	68269	—	—	—	696	60.0%	1.42
8/13/96	55	600	82.5	33	68319	—	—	—	696	60.0%	1.42
8/14/96	55	600	82.5	33	68368	—	—	—	696	60.0%	1.42
8/15/96	55	600	82.5	33	68418	—	—	—	696	60.0%	1.43
8/16/96	55	600	82.5	33	68467	—	—	—	696	60.0%	1.43
8/17/96	55	600	82.5	33	68517	—	—	—	696	60.0%	1.43
8/18/96	55	600	82.5	33	68566	—	—	—	696	60.0%	1.43
8/19/96	55	600	82.5	33	68616	—	—	—	696	60.0%	1.43
8/20/96	55	600	82.5	33	68665	—	—	—	696	60.0%	1.43
8/21/96	55	600	82.5	33	68715	—	—	—	696	60.0%	1.43
8/22/96	55	600	82.5	33	68764	—	—	—	696	60.0%	1.43
8/23/96	55	600	82.5	33	68814	—	—	—	696	60.0%	1.43
8/24/96	55	600	82.5	33	68863	—	—	—	696	60.0%	1.43
8/25/96	55	600	82.5	33	68913	—	—	—	696	60.0%	1.44
8/26/96	55	600	82.5	33	68962	—	—	—	696	60.0%	1.44
8/27/96	55	600	82.5	33	69012	—	—	—	696	60.0%	1.44
8/28/96	55	600	82.5	33	69061	—	—	—	696	60.0%	1.44
8/29/96	55	600	82.5	33	69111	—	—	—	696	60.0%	1.44
8/30/96	55	600	82.5	33	69160	—	—	—	696	60.0%	1.44
8/31/96	55	600	82.5	33	69210	—	—	—	696	60.0%	1.44
9/1/96	55	600	82.5	41	69251	—	—	—	696	50.0%	1.44
9/2/96	55	600	82.5	41	69292	—	—	—	696	50.0%	1.44
9/3/96	55	600	82.5	41	69333	—	—	—	696	50.0%	1.44
9/4/96	55	600	82.5	41	69375	—	—	—	696	50.0%	1.45
9/5/96	55	600	82.5	41	69416	—	—	—	696	50.0%	1.45
9/6/96	55	600	82.5	41	69457	—	—	—	696	50.0%	1.45
9/7/96	55	600	82.5	41	69498	—	—	—	696	50.0%	1.45
9/8/96	55	600	82.5	41	69540	—	—	—	696	50.0%	1.45
9/9/96	55	600	82.5	41	69581	—	—	—	696	50.0%	1.45
9/10/96	55	600	82.5	41	69622	—	—	—	696	50.0%	1.45
9/11/96	55	600	82.5	41	69663	—	—	—	696	50.0%	1.45
9/12/96	55	600	82.5	41	69705	—	—	—	696	50.0%	1.45
9/13/96	55	600	82.5	41	69746	—	—	—	696	50.0%	1.45
9/14/96	55	600	82.5	41	69787	—	—	—	696	50.0%	1.45
9/15/96	55	600	82.5	41	69828	—	—	—	696	50.0%	1.45
9/16/96	55	600	82.5	41	69870	—	—	—	696	50.0%	1.46
9/17/96	55	600	82.5	41	69911	—	—	—	696	50.0%	1.46
9/18/96	55	600	82.5	41	69952	—	—	—	696	50.0%	1.46
9/19/96	55	600	82.5	41	69993	—	—	—	696	50.0%	1.46
9/20/96	55	600	82.5	41	70035	—	—	—	696	50.0%	1.46
9/21/96	55	600	82.5	41	70076	—	—	—	696	50.0%	1.46
9/22/96	55	600	82.5	41	70117	—	—	—	696	50.0%	1.46
9/23/96	55	600	82.5	41	70158	—	—	—	696	50.0%	1.46
9/24/96	55	600	82.5	41	70200	—	—	—	696	50.0%	1.46
9/25/96	55	600	82.5	41	70241	—	—	—	696	50.0%	1.46
9/26/96	55	600	82.5	41	70282	—	—	—	696	50.0%	1.46
9/27/96	55	600	82.5	41	70323	—	—	—	696	50.0%	1.47
9/28/96	55	600	82.5	41	70365	—	—	—	696	50.0%	1.47
9/29/96	55	600	82.5	41	70406	—	—	—	696	50.0%	1.47
9/30/96	55	600	82.5	41	70447	—	—	—	696	50.0%	1.47
10/1/96	55	600	82.5	41	70488	—	—	—	696	50.0%	1.47
10/2/96	55	600	82.5	41	70530	—	—	—	696	50.0%	1.47
10/3/96	55	600	82.5	41	70571	—	—	—	696	50.0%	1.47
10/4/96	55	600	82.5	41	70612	—	—	—	696	50.0%	1.47
10/5/96	55	600	82.5	41	70653	—	—	—	696	50.0%	1.47
10/6/96	55	600	82.5	41	70695	—	—	—	696	50.0%	1.47
10/7/96	55	600	82.5	41	70736	—	—	—	696	50.0%	1.47
10/8/96	55	600	82.5	41	70777	—	—	—	696	50.0%	1.47
10/9/96	55	600	82.5	41	70818	—	—	—	696	50.0%	1.48

DOE/CVU CO_2 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.
10/10/96	55	600	82.5	41	70860	—	—	—	696	50.0%	1.48
10/11/96	55	600	82.5	41	70901	—	—	—	696	50.0%	1.48
10/12/96	55	600	82.5	41	70942	—	—	—	696	50.0%	1.48
10/13/96	55	600	82.5	41	70983	—	—	—	696	50.0%	1.48
10/14/96	55	600	82.5	41	71025	—	—	—	696	50.0%	1.48
10/15/96	55	600	82.5	41	71066	—	—	—	696	50.0%	1.48
10/16/96	55	600	82.5	41	71107	—	—	—	696	50.0%	1.48
10/17/96	55	600	82.5	41	71148	—	—	—	696	50.0%	1.48
10/18/96	55	600	82.5	50	71181	—	—	—	696	40.0%	1.48
10/19/96	55	600	82.5	50	71214	—	—	—	696	40.0%	1.48
10/20/96	55	600	82.5	50	71247	—	—	—	696	40.0%	1.48
10/21/96	55	600	82.5	50	71280	—	—	—	696	40.0%	1.49
10/22/96	55	600	82.5	50	71313	—	—	—	696	40.0%	1.49
10/23/96	55	600	82.5	50	71346	—	—	—	696	40.0%	1.49
10/24/96	55	600	82.5	50	71379	—	—	—	696	40.0%	1.49
10/25/96	55	600	82.5	50	71412	—	—	—	696	40.0%	1.49
10/26/96	55	600	82.5	50	71445	—	—	—	696	40.0%	1.49
10/27/96	55	600	82.5	50	71478	—	—	—	696	40.0%	1.49
10/28/96	55	600	82.5	50	71511	—	—	—	696	40.0%	1.49
10/29/96	55	600	82.5	50	71544	—	—	—	696	40.0%	1.49
10/30/96	55	600	82.5	50	71577	—	—	—	696	40.0%	1.49
10/31/96	55	600	82.5	50	71610	—	—	—	696	40.0%	1.49
11/1/96	55	600	82.5	50	71643	—	—	—	696	40.0%	1.49
11/2/96	55	600	82.5	50	71676	—	—	—	696	40.0%	1.49
11/3/96	55	600	82.5	50	71709	—	—	—	696	40.0%	1.49
11/4/96	55	600	82.5	50	71742	—	—	—	696	40.0%	1.49
11/5/96	55	600	82.5	50	71775	—	—	—	696	40.0%	1.50
11/6/96	55	600	82.5	50	71808	—	—	—	696	40.0%	1.50
11/7/96	55	600	82.5	50	71841	—	—	—	696	40.0%	1.50
11/8/96	55	600	82.5	50	71874	—	—	—	696	40.0%	1.50
11/9/96	55	600	82.5	50	71907	—	—	—	696	40.0%	1.50
11/10/96	55	600	82.5	50	71940	—	—	—	696	40.0%	1.50
11/11/96	55	600	82.5	50	71973	—	—	—	696	40.0%	1.50
11/12/96	55	600	82.5	50	72006	—	—	—	696	40.0%	1.50
11/13/96	55	600	82.5	50	72039	—	—	—	696	40.0%	1.50
11/14/96	55	600	82.5	50	72072	—	—	—	696	40.0%	1.50
11/15/96	55	600	82.5	50	72105	—	—	—	696	40.0%	1.50
11/16/96	55	600	82.5	50	72138	—	—	—	696	40.0%	1.50
11/17/96	55	600	82.5	50	72171	—	—	—	696	40.0%	1.50
11/18/96	55	600	82.5	50	72204	—	—	—	696	40.0%	1.50
11/19/96	55	600	82.5	50	72237	—	—	—	696	40.0%	1.50
11/20/96	55	600	82.5	50	72270	—	—	—	696	40.0%	1.51
11/21/96	55	600	82.5	50	72303	—	—	—	696	40.0%	1.51
11/22/96	55	600	82.5	50	72336	—	—	—	696	40.0%	1.51
11/23/96	55	600	82.5	50	72369	—	—	—	696	40.0%	1.51
11/24/96	55	600	82.5	50	72402	—	—	—	696	40.0%	1.51
11/25/96	55	600	82.5	50	72435	—	—	—	696	40.0%	1.51
11/26/96	55	600	82.5	50	72468	—	—	—	696	40.0%	1.51
11/27/96	55	600	82.5	50	72501	—	—	—	696	40.0%	1.51
11/28/96	55	600	82.5	50	72534	—	—	—	696	40.0%	1.51
11/29/96	55	600	82.5	50	72567	—	—	—	696	40.0%	1.51
11/30/96	55	600	82.5	50	72600	—	—	—	696	40.0%	1.51
12/1/96	55	600	82.5	58	72625	—	—	—	696	30.0%	1.51
12/2/96	55	600	82.5	58	72650	—	—	—	696	30.0%	1.51
12/3/96	55	600	82.5	58	72675	—	—	—	696	30.0%	1.51
12/4/96	55	600	82.5	58	72699	—	—	—	696	30.0%	1.51
12/5/96	55	600	82.5	58	72724	—	—	—	696	30.0%	1.52
12/6/96	55	600	82.5	58	72749	—	—	—	696	30.0%	1.52
12/7/96	55	600	82.5	58	72774	—	—	—	696	30.0%	1.52
12/8/96	55	600	82.5	58	72798	—	—	—	696	30.0%	1.52
12/9/96	55	600	82.5	58	72823	—	—	—	696	30.0%	1.52
12/10/96	55	600	82.5	58	72848	—	—	—	696	30.0%	1.52
12/11/96	55	600	82.5	58	72873	—	—	—	696	30.0%	1.52
12/12/96	55	600	82.5	58	72897	—	—	—	696	30.0%	1.52

VIP-COMP Simulation Input/Output Data
is available on 3.5" diskette.