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POST WATERFLOOD CO_2 MISCIBLE FLOOD IN LIGHT OIL FLUVIAL DOMINATED DELTAIC RESERVOIR – PRE-WORK AND PROJECT APPENDIX

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June 1, 1993-December 31, 1997

By:
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Pre-Work and Project Appendix

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APPENDIX A

STATEMENT OF WORK

PORT NECHES MISCIBLE CO_2 FLOODING DEMONSTRATION PROJECT

A. Introduction and Background

Texaco Exploration and Production Company (TEPI) and the U.S. Department of Energy (DOE) have agreed to enter into a cost-shared Cooperative Agreement for an Enhanced Oil Recovery Demonstration Project to recover moveable and residual oil in the Marginulina sand, Port Neches field, using the Miscible CO_2 flooding process and horizontal drilling. This project resulted from Texaco's proposal in response to DOE Program Opportunity Notice (PON) DE-PS22-92BC14805 titled "Class I Oil Program: Mid-Term Activities", dated October 15, 1991, and will be referred to as the "Port Neches Project" or "the Project" hereinafter.

B. General Requirements

The first principal objective of the Port Neches Project is to determine the feasibility and producibility of CO_2 miscible flooding techniques enhanced with horizontal drilling applied to a Fluvial Dominated Deltaic reservoir. The second principal objective of the Project is to disseminate the knowledge gained through established Technology Transfer mechanisms to support DOE's programmatic objectives of increasing domestic oil production and reducing abandonment of oil fields.

TEPI has acquired 100% of the rights to the Port Neches field and will provide the site for the Project, which is described in Attachment A to this Statement of Work. Texaco will provide the management, planning, reservoir characterization, recovery and production system design, engineering support, subsurface and surface facilities, equipment, CO_2, and site operations

necessary to develop and demonstrate producibility of the Port Neches field. DOE will make available any pertinent technical information to which it has rights should the need in support of this project be identified by TEPI, and will be responsible for obtaining any NEPA Compliance approvals and permits required for the project to proceed should these become necessary. In particular, DOE will obtain any necessary NEPA permits and approvals in timeframes consistent with the approved project schedule. The distribution of costs between TEPI and DOE for the project is specified elsewhere in the contract to which this SOW is attached.

C. Tasks to be Performed

C.1 Planning and Analysis

Texaco has performed the planning, analysis, and management required to demonstrate the feasibility and producibility of the Port Neches reservoir using miscible CO_2 flooding and horizontal drilling.

C.1.1 Management and Administration

Texaco acquired 100% working interest rights to the demonstration portion of Port Neches field for the purposes of this project, and provides the management and technical organization, engineering, technology resources, and operations support necessary to complete the demonstration.

The project is planned and budgeted in accordance with Texaco's normal business practices. A detailed project schedule and budget will be prepared and maintained for the life of the project, updating as necessary. Economic analyses of the project's performance was

prepared in accordance with Texaco's normal practices for use in determining the feasibility and producibility of the technology demonstration. Quarterly Project Review meetings will be held at sites and times mutually agreeable to Texaco and DOE, where summaries of project engineering, production, and financial status will be presented to and discussed with DOE.

C.1.2 Reservoir Characterization

The reservoir of Marginulina sands in the Port Neches field will be thoroughly characterized, in a manner consistent with Texaco's normal practices, and with any enhancements necessary for the purpose of determining feasibility and producibility of CO_2 miscible flooding in FDD reservoirs.

Reservoir characterization studies have included: Depositional Analysis including updated field studies, Paleontology studies on cuttings and cores from the newly drilled wells, core analysis both on sidewall cores and whole sleeved cores, bottom hole pressure tests including buildup, drawdown and injectivity to estimate permeability and identify flow channels, and tracer tests to determine overall extend ad direction of channels.

Laboratory analyses included: measurements of permeability and porosity of core samples; vaporization tests; determination of phase behavior of oil, determination of equation of state, gravity and viscosity.

Reservoir simulation analyses was conducted using Texaco's COMPIII simulation tool, and others to predict the behavior and sweep efficiency of the CO_2 flood. The analyses investigated the reservoir's production sensitivity to oil saturation, WAG ratios, and Dykstra-Parsons coefficients. Relative permeability curves will be developed and predictions of

average current oil saturation will be calculated.

C.1.3 Extraction Technology Design and Engineering

The project design of the Port Neches Field Marginulina miscible CO_2 flood begins with raising the reservoir pressure is below to the minimum miscibility pressure of 3310 psia. The reservoir pressure will be raised by the injection of produced saltwater at high rates beginning in 1992 after project selection.

All of the produced water from the field will be routed to a central location so that it can be pumped into the reservoir by a larger saltwater injection pump.

Reservoir pressure surveys will be run to insure that reservoir pressure is being raised, and to ensure integrity of the identified fault blocks.

If the project area's pressure cannot be raised to above the minimum miscibility pressure (MMP), the flood will be operated at the optimum vaporization pressure (OVP). This pressure provides optimum vaporization in the reservoir.

Additional facilities for the project will be required due the corrosive nature of CO_2 and due to the requirements that production from the project area be kept separate from other field production. A tank battery consisting of oil storage tanks, water tanks, separators, gunbarrel separation equipment, oil and gas measurement devices, safety equipment, production manifolds, transfer pumps, and other necessary equipment, will be placed on a platform near the project site to handle all produced fluids.

Gas streams, composed primarily of CO_2 gas, will flow into two separate gas gathering

systems, one for low pressure (LP) gas and one for intermediate pressure (IP) gas, after going through separation at the tank battery. The low pressure gas will be at an approximate pressure of 70 psia (84.7 psia) at the tank battery site, and will flow from the tank battery to a compressor on land some 7000 feet away, through a 6" gas gathering line. This gas will be compressed at this point by a compressor onshore (requires maintenance and special piping to handle wet CO_2 gas) from 50 psia to approximately 550 psia and returned to the IP system in the field through a 4" line. From this point this IP gas combines with the IP gas from other wells in the project area which are capable of producing at this higher pressure, and is passed through an additional separator, then through a glycol dehydrator where the gas is dried, removing all water vapor.

A small 330 HP compressor will be set initially in 1993 to handle approximately 3 MMCFPD of CO_2/methane gases. This compressor will compress the IP gas stream from 500 psia to 2200 psia. During 1994, an additional compressor will be set to handle larger volumes of recycled CO_2 gases. This will provide a total recycle capacity of approximately 15 MMCFPD.

Three new infill wells are needed in this proposed project to be used as CO_2 injectors. Two new wells will be drilled in the large water-flooded fault block, to be used as CO_2 injectors around the original oil/water contact. One of these will be a horizontal well to allow for greater sweep efficiency of the residual oil column. There will also be a well drilled in the small fault block to be used as an injector or a possible producer in a block which currently has only one well. There is currently 1 well planned for 1992, 1 well (horizontal well) for 1993, and 1 well for 1994.

Twelve wells will be worked over to install stainless steel sand control equipment and corrosion protected tubing, packers, and wellheads. Some wells will require repair of possible

holes in the casing strings, shutting off of perforated zones, drilling to the Marginulina reservoir, and addition of perforations in the sand. There may arise a need to cut a window in the casing, drill through the Marginulina sand, and set an additional string of casing on one of the wells. There are currently 4 workovers scheduled for 1992, 7 for 1993, and 1 for 1994. Three wells will be CO_2/water injectors and nine wells will be producers.

New corrosion protected flowlines will be required on all wells. Injection CO_2/water lines will be run along side of one another, as will the production lines, when possible. Several lines may be laid at one time to reduce costs necessary to install the lines.

Reservoir design considerations and reservoir modeling indicates that this project will require the purchase of 8.5 BCF (494,186 tons) of CO_2. This 40% HCPV figure was determined by using a modified version of the DOE CO2PM program, suggesting that only a small incremental volume of oil could be recovered by continuing purchases.

Limitations of the CO2PM program such as its 5-spot configuration; assumptions of constant porosity, oil saturation, and sand thickness; and constant CO_2 injection rates; justified Texaco's purchase of a Compositional simulation model where all properties of the reservoir can be entered into a grid system. This COMPIII (Scientific Software Intercomp Inc.) model has been utilized to improve the production forecast developed by CO2PM. It was at this point where Texaco recognized the compartmentalized nature of the fluvial dominated deltaic reservoir. The ability to contact these high oil saturations of the reservoir quickly, allows the production profile to be improved, thus increasing the rate of return of a CO_2 project.

Texaco will perform periodic bottomhole pressure surveys throughout the project to insure reservoir integrity. A monthly balance sheet will be prepared showing the gross production

from the reservoir (oil, water, gas, CO_2) and the total injection. A calculation of reservoir voidage will made to insure that the minimum miscibility pressure (MMP) or the optimum vaporization pressure (OVP) is maintained.

Tracer surveys will be run periodically to monitor the flow channels developing in the reservoir. These surveys will probably be run once per year, unless events occur which cannot be explained from surface production information. Proper monitoring of production and injection volumes, oil percentages, and gas stream compositions, will be sufficient in most cases.

C.1.4 Environment, Health & Safety

Texaco will comply with all applicable environment, health and safety regulations, and be responsible for obtaining all permits normally required to operate a drilling and production site. DOE will be responsible for any required actions to achieve NEPA compliance.

In addition, Texaco will perform the following specific actions:

- Reevaluate the existing Health and Safety training program to determine special training required for working with CO_2 and horizontal drilling equipment.

- Obtain Army Corps of Engineers permits for dredging, platform construction, and the CO_2 pipeline.

- Obtain State of Texas Water Quality Permit for dredging.

- Obtain U.S. Fish and Wildlife Service approval for the CO_2 pipeline.

C.2 Implementation and Demonstration

C.2.1 Management and Administration

During the Implementation and Demonstration Phase of the Project, Texaco will continue to provide management oversight, project control accounting, Project Reviews, and reporting described in section C.1.3 above and in Section D.

Texaco will also maintain an ongoing economic analysis of project performance, and report on economic performance at the Quarterly Project Reviews. Records of daily oil, water, and gas production and injection will be kept for the life of the project demonstration. These records will be filed with the State of Texas as required by Texas law. All other deliverables as listed in Section D will be prepared and delivered as specified.

C.2.2 Reservoir Characterization

During the Implementation and Demonstration Phase, reservoir simulation work will be performed, updating the COMPIII models as actual geologic and production data are acquired. Data taken from analysis of rock samples from the new well drillings will be used to update the COMPIII models. Analyses will be run to obtain the best match between actual oil, water, and gas production figures and the predictions of the reservoir simulation model. A topical report describing the results will be published at the end of Phase II.

C.2.3 Site Operation and Field Work

In development of the Port Neches Marginulina reservoir for miscible CO_2 flooding and horizontal drilling, the following work will be done:

Drill Polk "B" No. 38 to 6000 feet and complete in Marginulina reservoir during 1992. Complete it as an oil producer using gas lift equipment to unload the well.

Drill W.H. Stark "B" No. 36 as an injector for CO_2 during 1993.

Drill H.J. Kuhn No. 54 as an injector for CO_2 during 1993.

Drill Polk "B" No. 39 as an injector for CO_2 during 1994.

Perform W.H. Stark No. 10 workover in May, 1992 and convert to water injector.

Workover H.J. Kuhn No 14 to producer in June, 1992.

Workover H.J. Kuhn No. 36 to water injector in July, 1992.

Workover W.H. Stark No. 7 to producer in August 1992.

Workover Kuhn No. 17 to CO_2/water injector in 1993.

Workover Kuhn No. 38 as producer in 1993.

Workover Stark 8 as producer in 1993.

Workover Kuhn 33 as producer in 1993.

Workover Kuhn 15R as producer in 1993.

Workover Kuhn No. 6 as producer in 1993.

Workover Polk "B" No. 5 during 1994.

Well workovers will be done to install stainless steel screen and liners and corrosion protected tubing and well heads.

For surface facilities, the following work will be done:

- Install larger saltwater pump to inject approximately 4400 BWPD at 2000 psia.
- Construct new production platform specifically for the Port Neches Project.
- Install a compressor to handle 5 mmcfpd of produced CO_2 at pressures above 500 psia on a production barge near the project area wells.
- Install a larger compressor to handle an additional 10mmcfpd of recycled CO_2 in 1994.
- Repair and modify an existing compressor to handle the compression of low pressure CO_2 during 1992.
- Install new tank battery last quarter 1992, including 6 500bbl oil storage tanks, 2 500 bbl water tanks and a gunbarrel for separating the oil and water. Install safety equipment to guard against oil spills in the event of equipment failures.
- Install high pressure flowlines to all wells.

C.2.4 CO_2

Texaco will secure the most cost effective source of CO_2 for the miscible CO_2 flooding process and provide the management oversight required to bring the CO_2 to the site, including acquiring all State and Local permits and Right of Ways.

For monitoring project performance, the following work will be done:

- Install the CO_2 pipeline from the third party supplier of CO_2 over the 4 1/2 miles to his compressor from the Port Neches field.

- Measure daily oil and water production from the tank batteries and allocate to producing wells.

- Measurements of the surface pressure, water injection, back pressure, and CO_2 injection volumes will be taken daily.

- For the span of the production period, the production and additional geologic data will be used to update the reservoir simulation models to forecast future performance of the reservoir and validate the technical approach taken for the project.

C.2.5 Environment, Health, and Safety Monitoring and Compliance

The following specific actions will be performed:

A spill prevention control, containment and countermeasure plan will be developed and maintained/revised on a regular basis as project drilling and operations proceed.

An employee EH&S training program for the Port Neches Project will be developed and implemented for the life of the Project.

Waste streams from drilling and production will be characterized and the information made available for support in permitting activities. Obtain waste disposal permits from the State of Texas.

Characterize air emissions from the compressors, pumps, and dehydrators, and obtain required air quality permits.

Obtain Corps of Engineers Permits for the CO_2 pipeline, platform construction, and compressor barges.

Define all pipeline issues under USDOT jurisdiction, develop required DOT manuals, and prepare the annual report to DOT.

Establish Project employee health and safety training programs specific to the Port Neches Project.

Preposition all booms, absorbent materials and other spill containment gear to a location near the Port Neches site.

C.3 Technology Transfer

Texaco will take action necessary to illustrate the general applicability of the process to similar reservoirs, as well as provide a means to evaluate the applicability of the process for specific reservoirs.

Texaco will document the anticipated improvement in sweep efficiency and describe the general ability of the process to overcome the obstacles to production posed by the characteristics of FDD reservoirs. The focus of this analysis will be to allow potential users to make a general evaluation of the applicability and potential results of the process. This documentation will be in the annual technical progress reports and will be discussed in technical detail in the SPE journal articles (see below).

To evaluate specific applications, Texaco will develop a model to screen reservoirs to determine the reservoir's suitability for application of miscible CO_2 flooding. This screening model will be parameter-driven, where the parameters represent specific characteristics of FDD reservoirs. The model will be designed to use parameter values derived from normally-available reservoir data, or from reservoir characterization methodology created and described as part of this study. Texaco will document the model basis and assumptions and make this

information available to the community of potential users through technical reports, presentations, and through Federal agencies for technology transfer such as the National Technical Information Service (NTIS) and the Office of Scientific and Technical Information (OSTI).

Texaco will identify reservoirs with similar drive mechanisms and geology, and provide a comprehensive estimate of the additional resource accessible due to the implementation of this technology. Similar reservoirs will be identified with the help of the Tertiary Oil Recovery Information System (TORIS) maintained by DOE, and the Louisiana State University (LSU). Texaco will also provide an analysis of the anticipated cost per barrel recoverable by the process. The analyses will take into account extrinsic factors that may impact each estimate. The volume of recoverable resource can be divided into two categories; the total volume recoverable regardless of price, and the volume economically recoverable at incremental crude oil price levels. Cost per recoverable barrel is dependent upon factors such as reservoir size and proximity to CO_2 source.

Texaco will provide an analysis of all anticipated environmental and socioeconomic constraints, including a specific analysis of the effects on global warming. The analysis will provide a general evaluation of the impact of each constraint on application of the process and describe the economic, geographic, and geologic circumstances under which the constraint is relevant. Further, Texaco will provide a summary and analysis of strategies to mitigate effects of constraining circumstances to permit implementation of the process.

Permitting problems encountered during the field test will be described and a detailed description of a methodology for resolving or avoiding the problems will be given. Texaco will provide an analysis of potential permitting problems that could be encountered during

application of the technique under other geologic or geographic circumstances.

Texaco will use the list of similar reservoirs so developed identify operators of fields where the technique may be applicable. The availability and proximity of CO_2 sources to these fields will also be determined. This information will be included in topical reports, and the annual technical progress reports. Sufficient information will be published to provide everything required by an independent operator to evaluate and implement the technical approach.

Texaco will prepare publications, seminars, and topical reports on their characterization work done in preparation and for completion of the project. To reach the widest possible audience, these works will be presented through the Society of Petroleum Engineers, NTIS, and OSTI as well as the Projects technical and topical reports.

D. Deliverables

Project deliverables are defined as shown below.

Deliverable	Info	Appr	Due	BPO	PETC
Monthly Federal Assistance Project Progress Reports	x		monthly	x	x
Annual Technical Progress Reports	x		annual	x	x
Monthly Financial Status Reports	x		monthly		x
1st Topical Report on Reservoir Characterization	x		10/92	x	
2nd Topical Report on Reservoir Characterization	x		10/94	x	
Monthly Production Reports	x		monthly	x	

Deliverable	Info	Appr	Due	BPO	PETC
Quarterly Federal Assistance Milestone Plan	x		quarterly	x	x
Quarterly Federal Assistance Management Report	x		quarterly		x
Initial Notice of Energy R&D	x		5/92		x
Quarterly Technical Progress Report	x		quarterly		x
Final Technology Transfer Plan	x		7/92	x	x
Final Topical Report on Reservoir Simulation and Performance	x		4/95	x	
1st SPE Journal Paper on Reservoir Characterization		x	4th quarter 92	x	x
Report on TORIS Update on FDD Reservoirs	x				
2nd SPE Journal Paper on Reservoir Characterization		x	4th quarter 94	x	x
SPE Journal Paper on Process Design		x	4th quarter 93	x	x
Final Project Technical Report	x		4th quarter 96	x	x
Environmental Data Packages	x		as need	x	
Project Procedures Manual	x		5/92	x	x

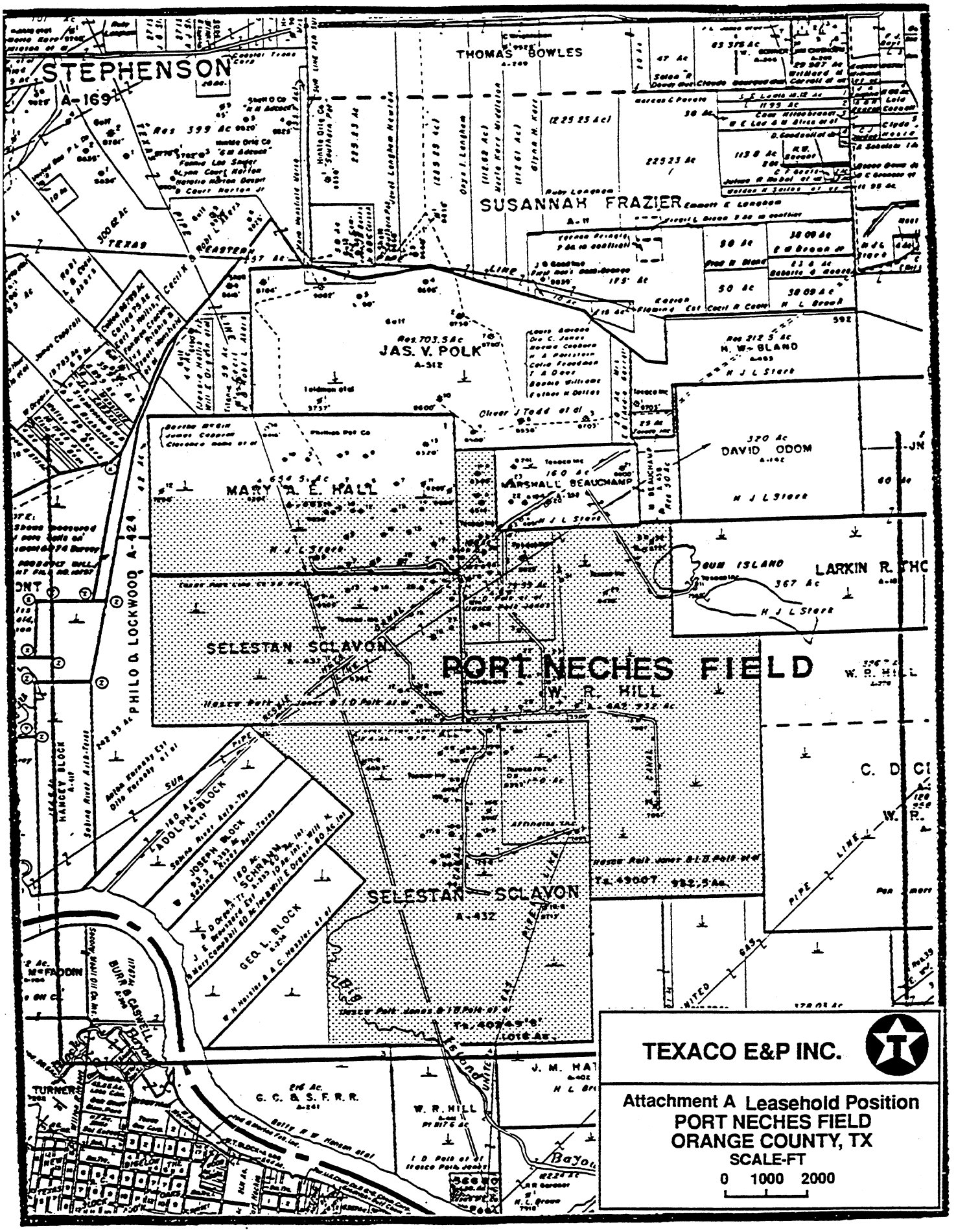
E. Project Reviews

Texaco will hold quarterly project reviews at which the Project Status will be reviewed with DOE. At these reviews Texaco will present summaries of design status, schedule status, updates on reservoir characterization, production performance, financial status, and significant project issues for discussion. Review Meetings will be held at mutually agreeable locations.

The overall project schedule is shown in Attachment B.

G. Location of Work

Work will be performed at Texaco's New Orleans, LA, Harvey LA, Sour Lake, TX, Houston, TX facilities and at SAIC's Mclean Facility, as well as the Port Neches Marginulina site near Port Arthur, TX.


STEPHENSON
A-169
THOMAS BOWLES
SUSANNAH FRAZIER
JAS. V. POLK
A-312
H. W. BLAND
DAVID ODOM
MARY A. E. HALL
MARSHALL BEAUCHAMP
GUM ISLAND
LARKIN R. THC
PHILO & LOCKWOOD A-424
SELESTAN SCLAVON
PORT NECHES FIELD
W. R. HILL
ADOLPH BLOCK
JOSEPH BLOCK
SCHRAMM
GEO. L. BLOCK
SELESTAN SCLAVON
A-432
McFADDIN
BURR & CASWELL
TURNER
G. C. & S. F. R. R.
W. R. HILL
J. M. HA
TEXACO E&P INC.
Attachment A Leasehold Position
PORT NECHES FIELD
ORANGE COUNTY, TX
SCALE-FT
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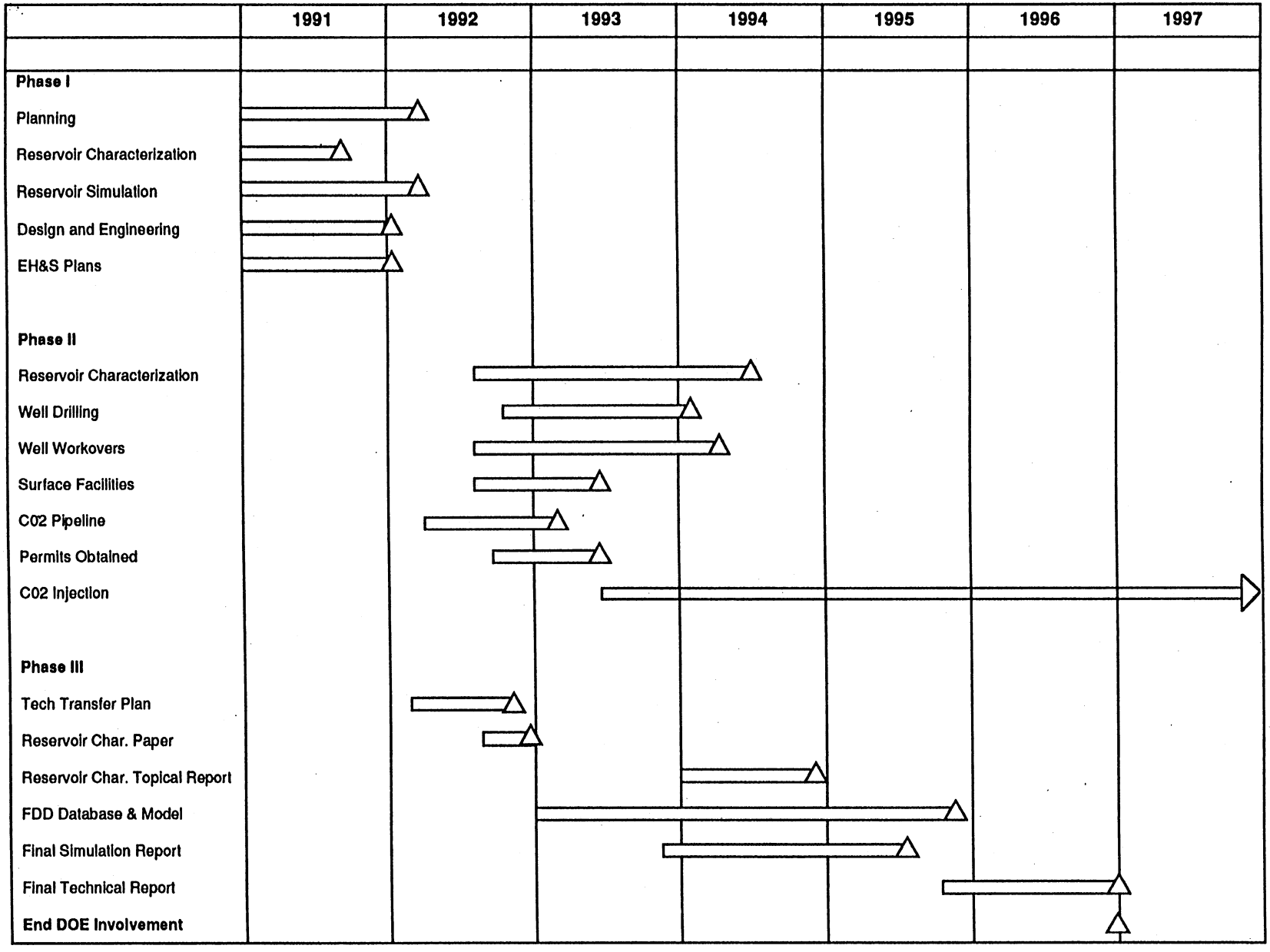


Attachment B Texaco Port Neches Miscible CQ Flood Demonstration Project Milestone Schedule

A REVIEW OF REPRESENTATIVE PALEONTOLOGICAL SUMMARIES IN ORDER TO AID IN THE DETERMINATION OF DEPOSITIONAL ENVIRONMENTS FOR THE MARGINULINA SAND OIL RESERVOIR

PORT NECHES FIELD
Orange County, Texas

A Review of Representative Paleontological Summaries in order to Aid in the Determination of Depositional Environments for the Marginulina Sand Oil Reservoir

December 20, 1991

Introduction

The Marginulina sand has been one of the most prolific oil reservoirs on the Port Neches Field, an intermediate piercement salt dome, which is located in the southern portion of Orange County, Texas. Five years after the initial field discovery, the first Marginulina sand completion was made in the Texaco Polk No. B-2 well drilled in 1934. Subsequent drilling has yielded numerous successful Marginulina sand completions, as well as, deeper Hackberry sand and shallower Miocene sand producers. The environments of deposition, as supported by representative paleontological summary reports, are diverse throughout the various producing horizons at Port Neches Field. The available paleontological summary reports which contained a breakdown of depositional environments have been reviewed in order to determine the zone of deposition for the Marginulina sand. These reports and selected Marginulina sand log sections are included in Appendix I and Appendix II attached to this report. The Marginulina sand is interpreted to have been deposited in zones typical of fluvial dominated deltaic environments, which are referenced in the summary paleontological reports. These zones of deposition are shown on the attached Figure 1 modified from Tipsword et. al., GCAGS Transactions, p. 122. Vol. 16, 1966.

Structural Interpretation

Structural complexities associated with the growth of the Port Neches structure are manifested by numerous graben faults in the Miocene interval on the crest of the field. The older Oligocene interval, which includes the Marginulina sand reservoir, is less complexly faulted. The domal uplift does appear to have had an impact on the sedimentation by generating several crestal disconformities and an apparent unconformity on the

southern portion of the field. One of the disconformities may be evident in the heart of the Margiulina sand reservoir, where several wells have no Marginulina sand. A large northwest-southeast trending down to the northeast fault bounds the main producing Marginulina sand oil reservoir on the southwest flank of field. Current subsurface mapping downthrown to this fault indicates the main productive Marginulina sand reservoir had been at least 1.7 miles long and .9 miles wide. The subject sand has been tested on the upthrown side of this significant fault system with only limited success. Hydrocarbons have been found in what is interpreted to be a stratigraphic trap of an upper member of the Marginulina sand interval which develops off structure to the southwest of the field. Deeper penetrations around the Port Neches salt dome have encountered deeper water depositional environments including the prolific Hackberry sand interval. Some of the deeper section around the salt dome has yet to be explored.

Depositional Environments

Although there were many paleontolgical reports available on the field at Port Neches, only fourteen paleontological reports included references to depositional environments. Eight of these fourteen paleontological reports, which depict the depositional environments for the Marginulina sand, have been included with type log sections as Appendix I. Four of the examples from Appendix I are discussed below as evidence that the Marginulina sand was deposited in a fluvial dominated deltaic environment. The remaining six reports are included in Appendix II. Unfortunately, none of the available reports were on wells associated with the main oil producing fault block of the Marginulina sand. Therefore, an additional twenty-six wells throughout the field were evaluated solely on the basis of log characteristics in order to aid in the interpretation of the Marginulina sand depositional environment.

Deposition associated with most fluvial dominated environments may be characterized by multiple channels

occurring on top of one another and side by side. This accumulation of sediments takes place in deltas, where a dominant river source is no longer confined to a single channel. These channel deposits will typically exhibit a coarse grain of sediments near the base of the interval which will gradually fine upwards within the sand body. The attached Type Log "A" of the Texaco Kuhn No. 46 well, through the Marginulina sand interval, demonstrates a coarse to fine texture from base to top. This is manifested by the slope of the GR, SP and resistivity curves through the subject sand. Although no breakdown of depositional environments was available on this well, these log characteristics are interpreted to be associated with a fluvial channel overbank facies. The Marginulina sand penetration by the Kuhn No. 46 well does occur in the main producing fault block of the oil reservoir, and is therefore, considered to be important in determining an associated depositional environment.

Type Log "B" attached to this report, shows the development of the Marginulina sand in the Texaco Orange County National Bank No. 9 well. The SP character of this log through the subject horizon represents a uniform grain size from the top to the bottom of the sand. Deposits with this log characteristic are interpreted to be associated with the delta plain facies.

The Marginulina sand in the log of the Texaco Polk-Kuhn-Glass No. 5 well, Type Log "C", has a characteristic SP of grain size that increases upward in the sand interval. This is interpreted to represent a distributary bar facies within a fluvial dominated deltaic system. The coarse grains near the top of the sand represent the increased energy associated with a prograding delta.

Several of the available paleontological reports indicate that the Marginulina sand is at, or near, a fluvial/beach-inner neritic depositional environment. The Port Neches Oil Orgain No. 1 well (Appendix I No. 1), located off structure to the southwest of the field, contained an extensive sequence of fluvial-continental deposits in the Miocene. This gives way to a beach and

inner-neritic interval just below the Marginulina sand into the top of the Frio sand interval.

The Texaco Orange County National Bank No. 2 (Appendix I No. 2), located on structure in the south-central portion of the field, exhibits a similar sequence of fluvial-continental and fluvial-brackish mixtures through most of the Miocene section. The Marginulina sand occurs in a beach-inner neritic zone indicative of deposition in water depths of 0-20 meters. It is noted that the Marginulina sand in this well is not as well developed as in some of the other wells in the field. The characteristic SP curve for coarse to fine upward is also not as evident in the log of this well. This is perhaps due to an increased number of fines in the sand on this portion of the lease.

The Texaco Polk B-6 well (Appendix I No. 6) is located 600' south of one of the most prolific Marginulina sand oil wells on the field (the Texaco Polk No. B-5). The Polk B-6 is also one of the closest wells to the main oil reservoir with a depositional environment classification. Although the Marginulina sand is faulted-out of the Polk B-6, a similar on structure alternation of fluvial/continental and brackish-beach/inner neritic environments is indicated near the interval of interest. These environments are considered to be representative of section found associated with a fluvial dominated deltaic system.

The Texaco Polk B-31 (Appendix I No. 8) contains sequences of bay, beach and inner neritic zones of deposition. The Marginulina sand in this well is developed in the beach zone as indicated in the paleontological report. It is noted that an additional sand has developed in this well in the <u>Marginulina vaginata</u> interval approximately 25' above the main Marginulina zone. This upper member is not present in wells on structure to the north of the B-31 well location. It is interpreted that the production in the upper sand is stratigraphically trapped in fluvial beach deposits in this vicinity of the field.

A model of the deltaic depositional sequences seen by the above referenced wells is shown in Figure 2 modified

from Coleman and Gagliano, S.E.P.M. Publication No. 12, p. 144, 1965. The approximate location of the Port Neches Field has been placed on this display covering several of the identified depositional zones. Those environments of deposition associated with the fluvial dominated delta deposits at Port Neches Field have been appropriately labeled.

Figure 3 is a depositional model for Port Neches Field which was generated by utilizing the previously referenced logs and paleontology. As depicted within the area of review, several depositional facies consistent with a fluvial dominated deltaic system have been interpreted. The delta plain facies and associated distributary bar facies are interpreted to have been deposited within an active, prograding, fluvial fed delta. The fluvial channel facies is deposited in the delta environment as the delta sediments prograde seaward. It is suggested that several northwest-southeast fluvial channels were active in the area of the subject field. This is perhaps due to a change in the position of the fluvial channel system.

Conclusion

The Marginulina sand at Port Neches Field is found associated with alternating zones of continental/fluvial deposits and brackish-beach/inner neritic deposits as demonstrated in available paleontological zonation reports. Although there were no environmental breakdowns for wells in the main Marginulina sand oil reservoir, log responses of the sand in wells in the producing fault block exhibited similar characteristics to those found in typical fluvial dominated deltaic systems. Therefore, it is concluded that the Marginulina sand has been deposited in a fluvial dominated deltaic environment. Rework of samples of key existing wellbores and evaluation of any new drilling wells through the subject sand may aid in a more detailed delineation of environments of deposition in various parts of the field.

The interpretation of well logs, paleontological reports, and stratigraphic implications are considered reasonable based upon the availability, reliability, and interpretation of all sources of data presented to the undersigned when this evaluation was requested. This report is furnished upon the condition that no errors arising out of or related to information contained herein will give rise to any right or claim against Alexander Enterprises, Inc., or the undersigned geologists.

submitted by Daniel O. Hall, II
Daniel O. Hall, II
Petroleum Geologist

approved by William C. Moody, Jr.
William C. Moody, Jr.
Certified Petroleum
Geologist No. 2298
American Association of
Petroleum Geologists

PROPERTY EVALUATION: Port Neches Field; Orange County, TX

DATE SIGNED: 3 January 1992

AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS
CERTIFIED PETROLEUM GEOLOGIST
WILLIAM C.
MOODY, JR.
2298
1917

CLASSIFICATION OF MARINE ENVIRONMENTS

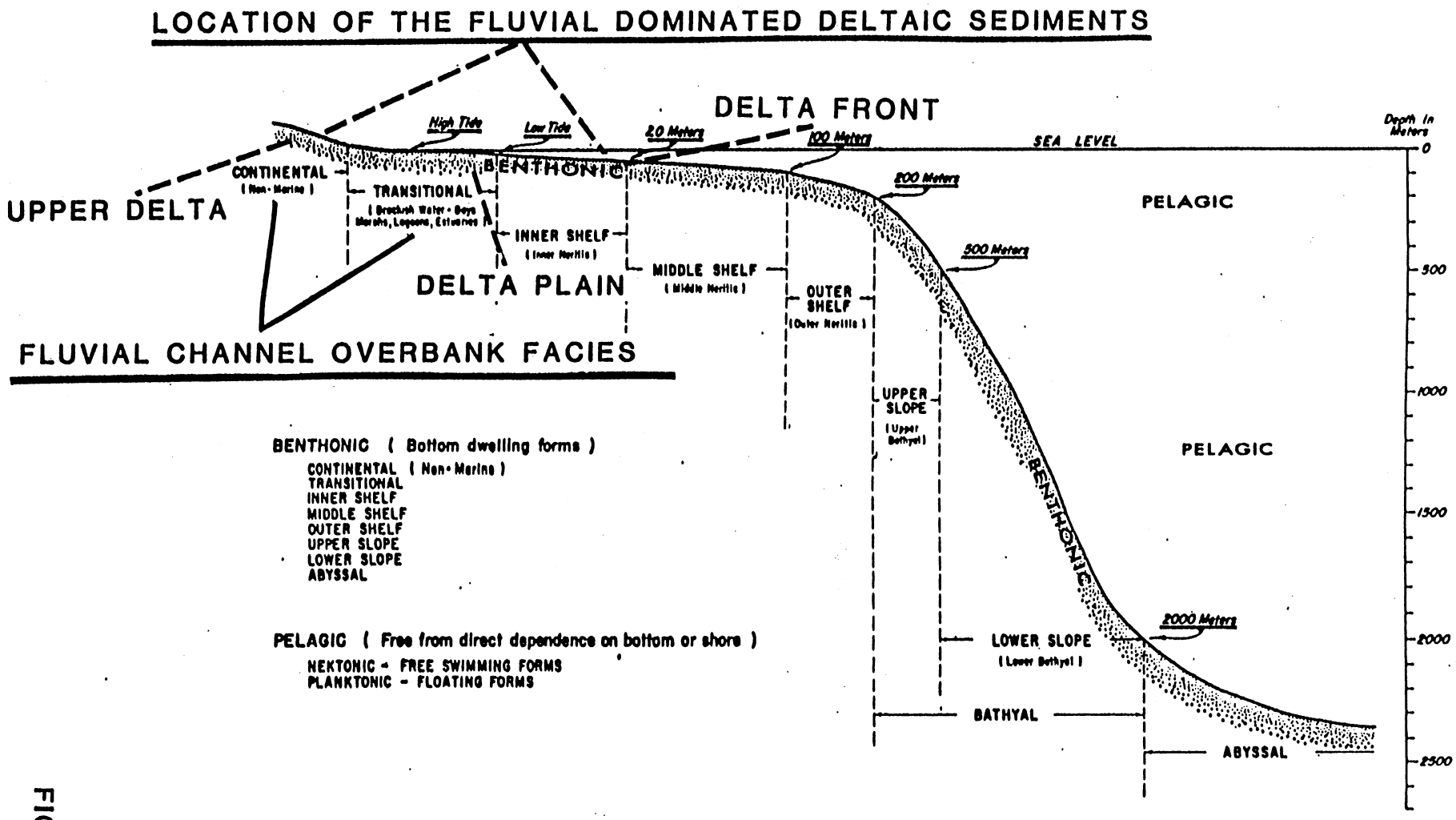
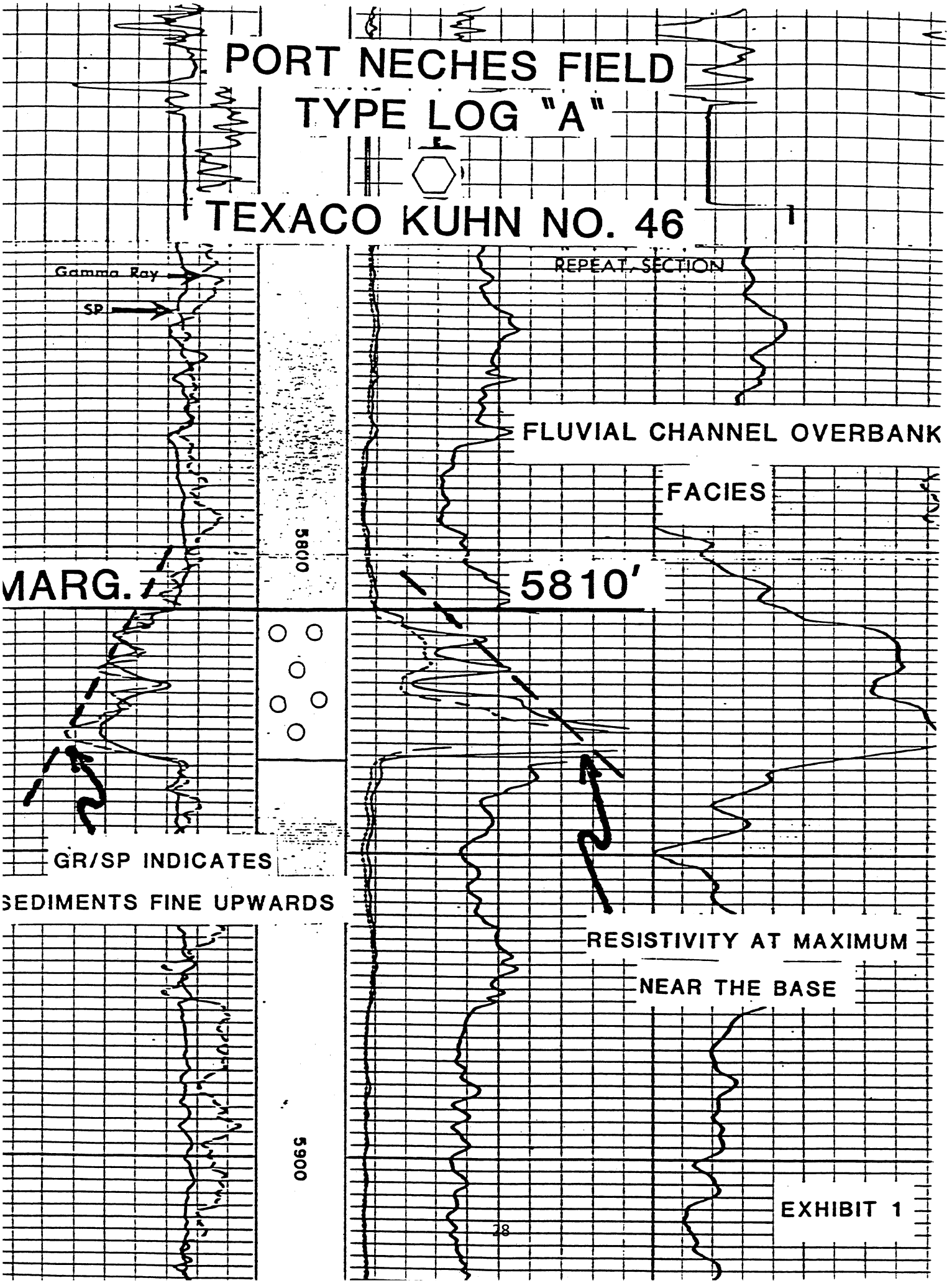


FIGURE 1

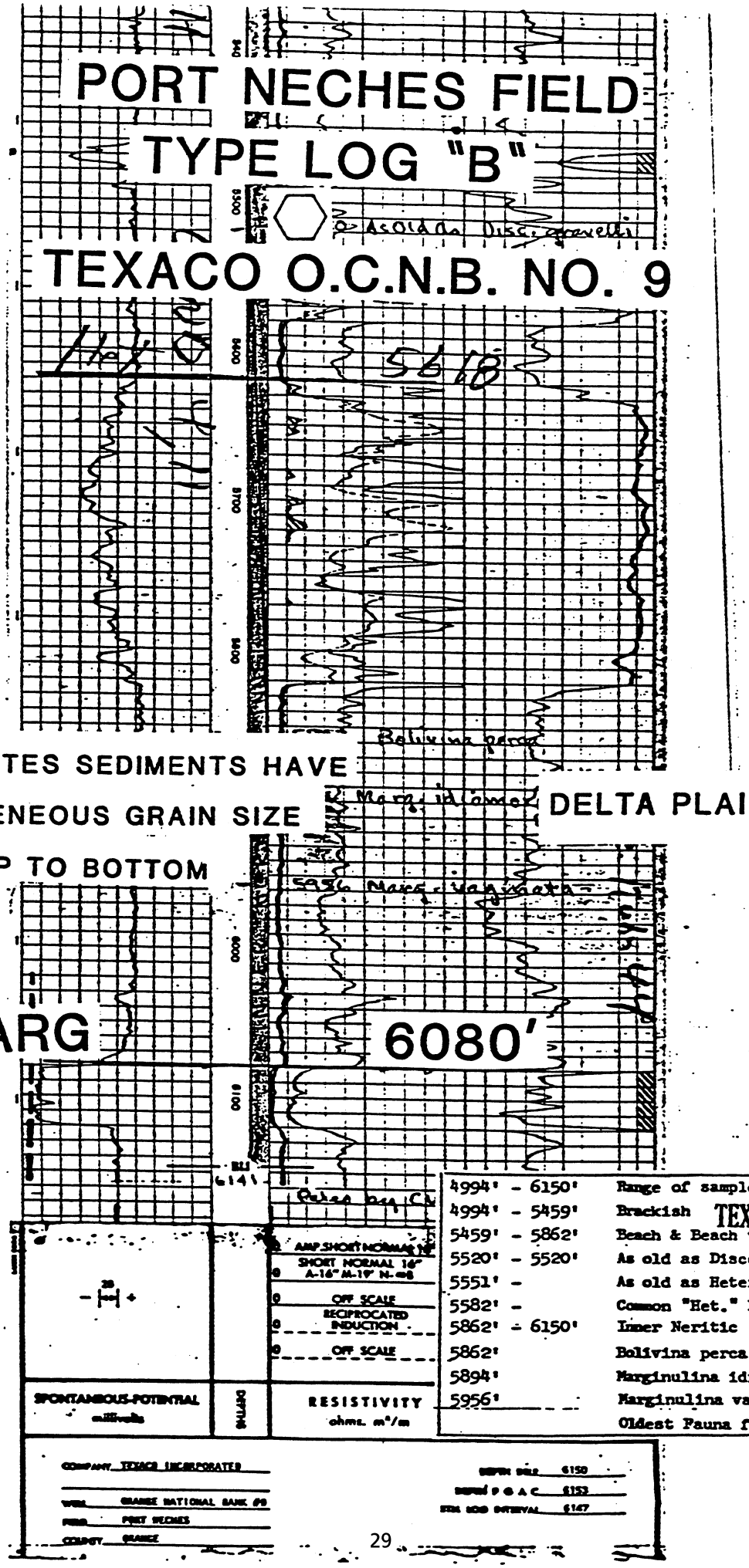

PORT NECHES FIELD
TYPE LOG "A"
TEXACO KUHN NO. 46
Gamma Ray
SP
REPEAT SECTION
FLUVIAL CHANNEL OVERBANK
FACIES
5800
MARG.
5810'
GR/SP INDICATES
SEDIMENTS FINE UPWARDS
RESISTIVITY AT MAXIMUM
NEAR THE BASE
5900
EXHIBIT 1

PORT NECHES FIELD

TYPE LOG "B"

TEXACO O.C.N.B. NO. 9

5



SP INDICATES SEDIMENTS HAVE HOMOGENEOUS GRAIN SIZE TOP TO BOTTOM

DELTA PLAIN FACIES

MARG

4994' - 6150'		Range of samples available & examined
4994' - 5459'		Brackish
5459' - 5862'		Beach & Beach to Inner Neritic
5520' - 5520'		As old as Discorbis gravelli
5551' -		As old as Heterostegina
5582' -		Common "Het." Lime
5862' - 6150'		Inner Neritic < Marg. Sd.
5862'		Bolivina perca
5894'		Marginulina idiomorpha
5956'		Marginulina vaginata
		Oldest Fauna found is Anahuac in age

TEXACO PALEO LAB

EXHIBIT 2

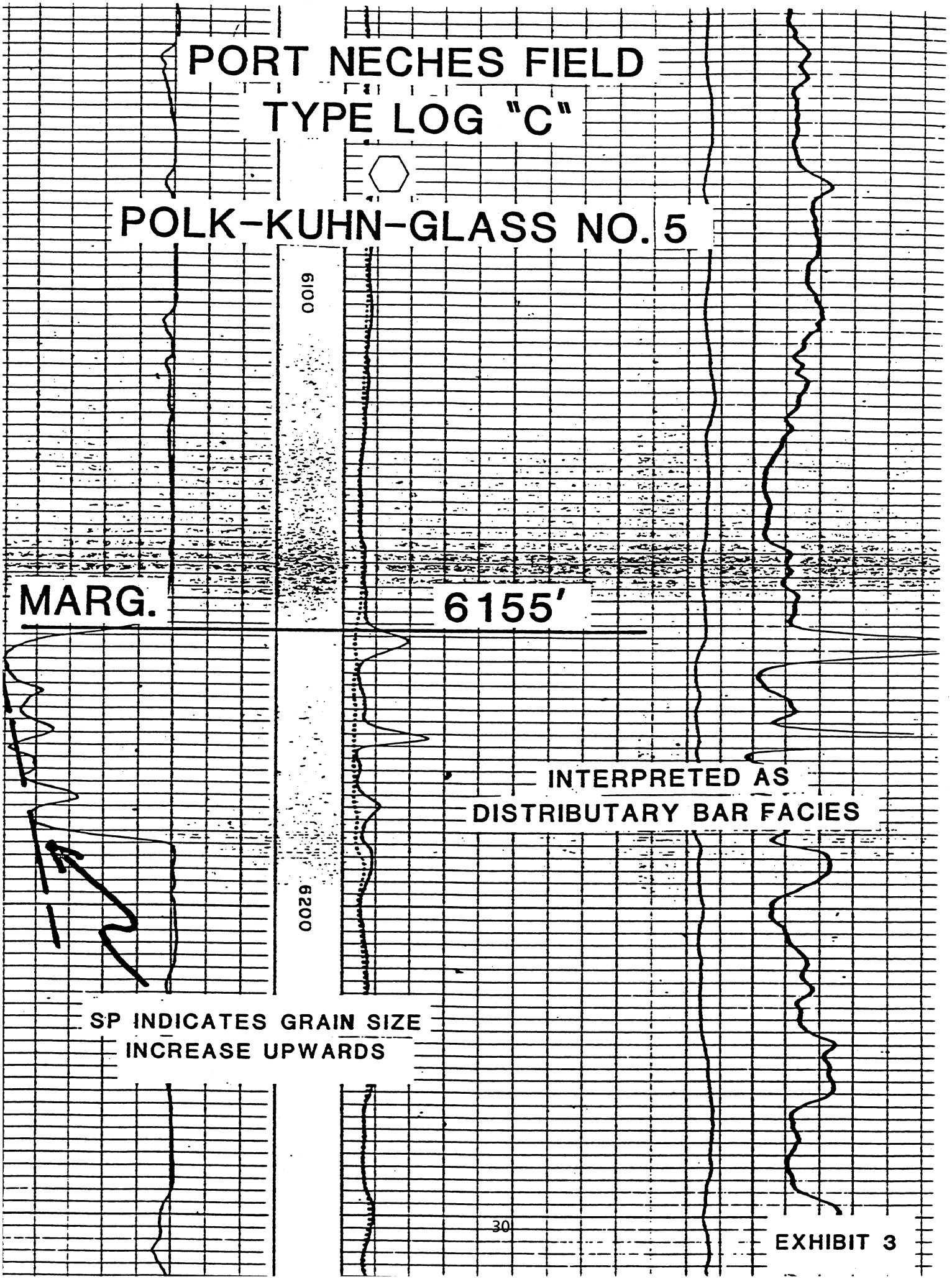
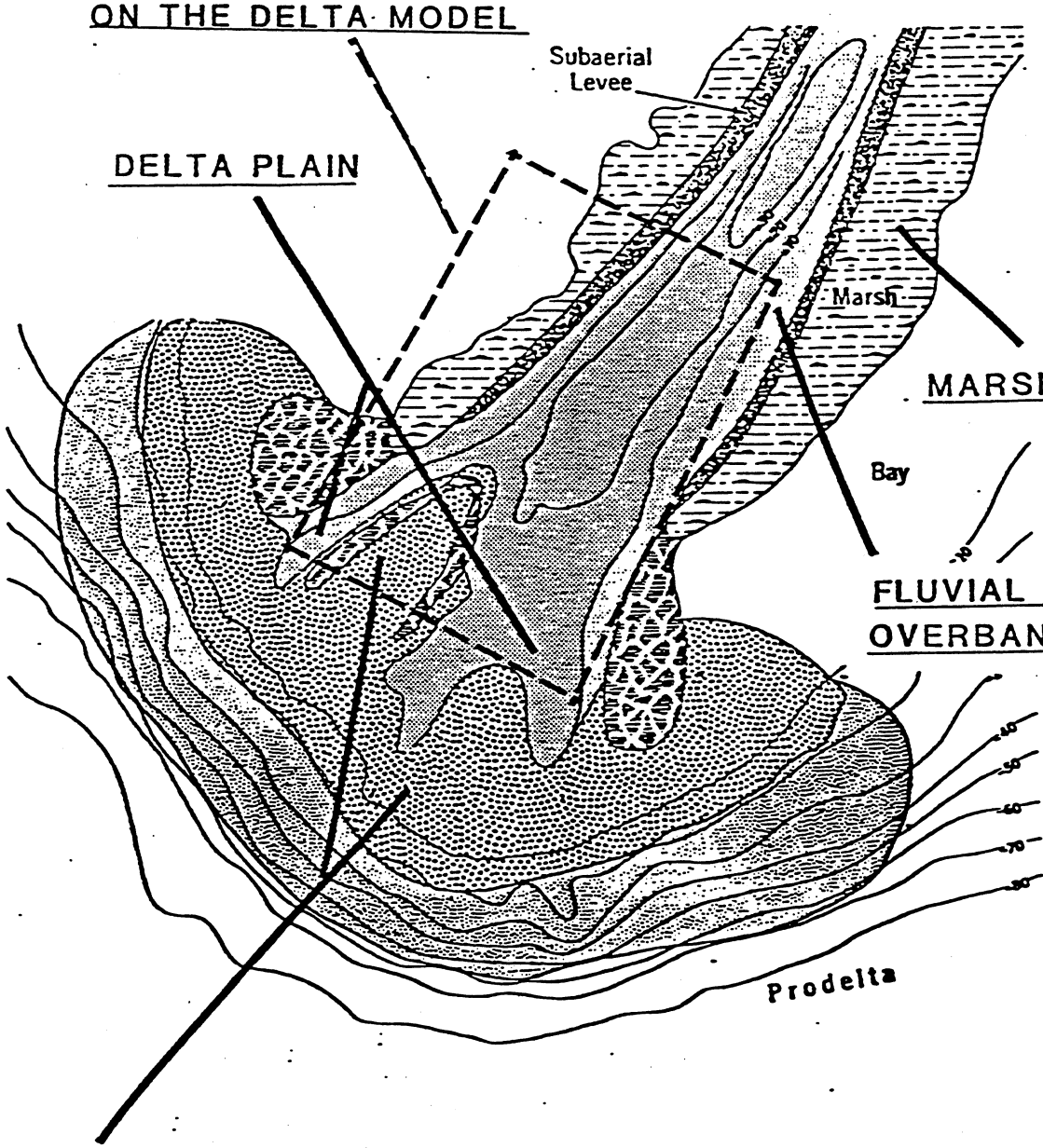

PORT NECHES FIELD
TYPE LOG "C"
POLK-KUHN-GLASS NO. 5
6100
MARG.
6155'
INTERPRETED AS
DISTRIBUTARY BAR FACIES
6200
SP INDICATES GRAIN SIZE
INCREASE UPWARDS

EXHIBIT 3

TYPICAL FLUVIAL DOMINATED DELTAIC DEPOSITS



DELTA FRONT SUBENVIRONMENTS AT THE MOUTH OF SOUTHWEST PASS, MISSISSIPPI RIVER DELTA. COLEMAN AND GAGLIANO, 1965

FIGURE 2

TEXACO E&P INC.

PORT NECHES FIELD
Orange County, Texas

0 5000
Feet

ALEXANDER ENTERPRISES, INC.

FLUVIAL DOMINATED DELTAIC DEPOSITS

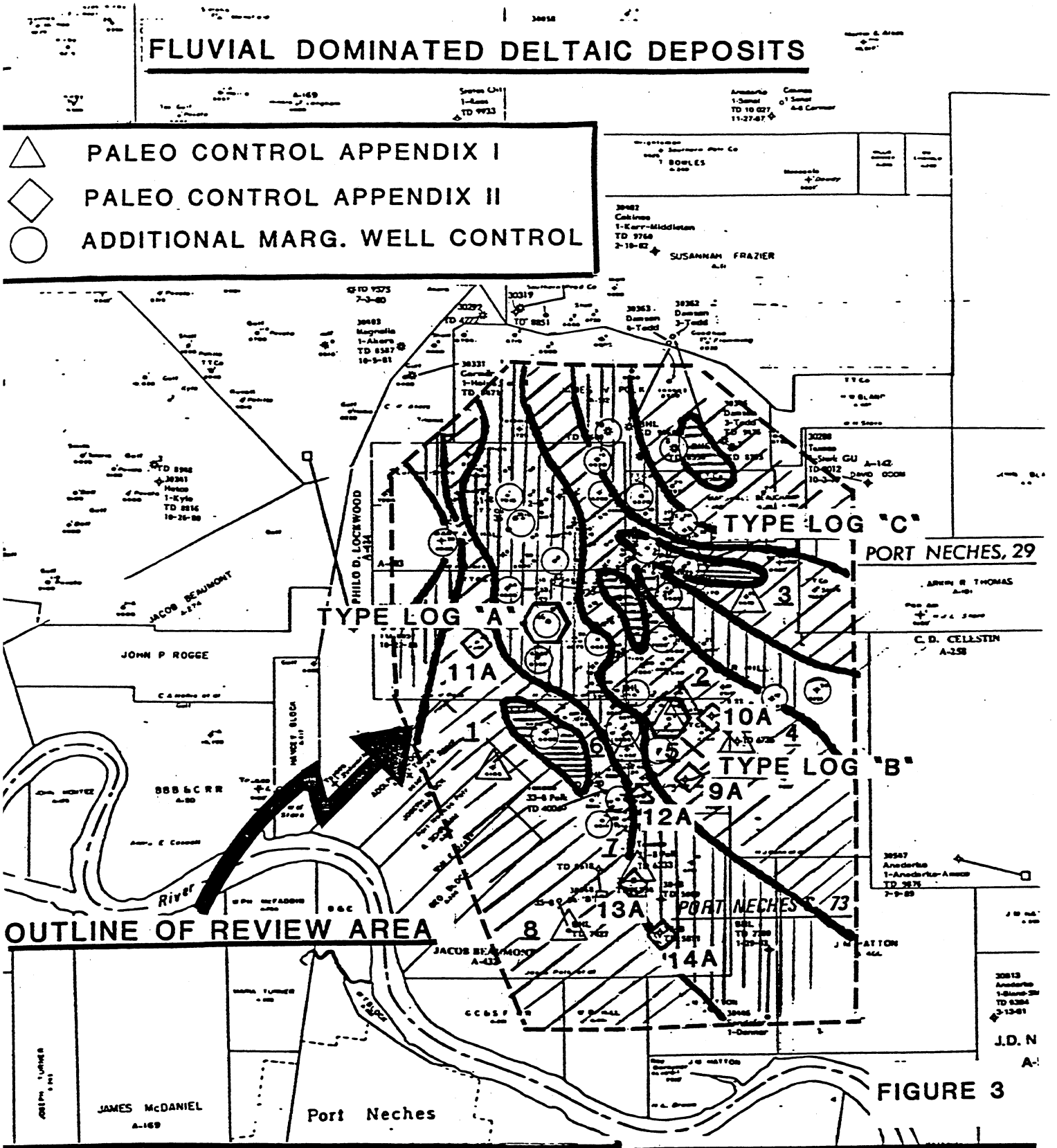


FIGURE 3

FLUVIAL CHANNEL OVERBANK FACIES

DELTA PLAIN FACIES

DISTRIBUTARY BAR FACIES

MARSH FACIES

TEXACO E&P INC.

PORT NECHES FIELD

Orange County, Texas

1" 4000'

ALEXANDER ENTERPRISES, INC.

APPENDIX I

PORT NECHES FIELD

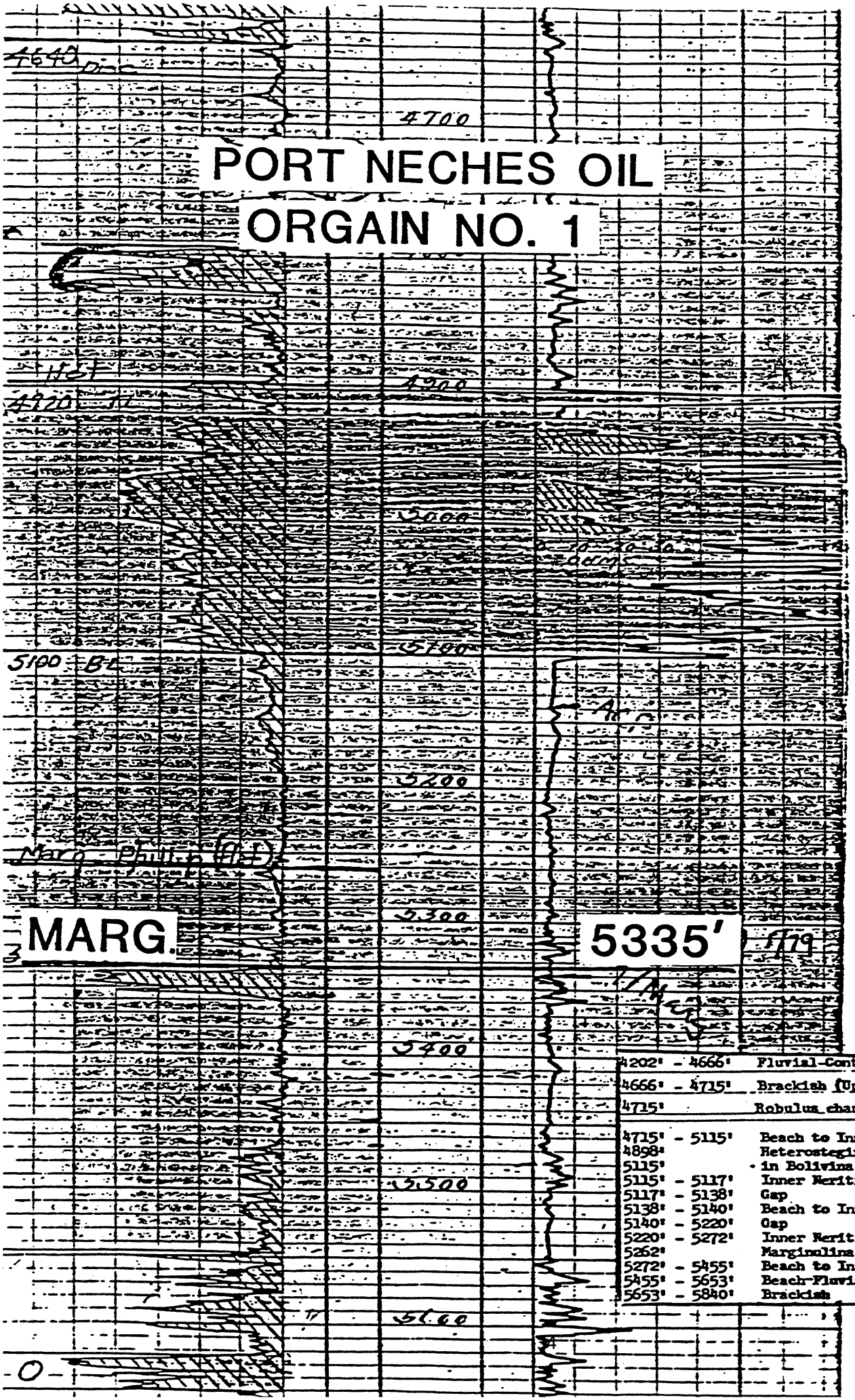
Representative Log Sections Through the

Marginulina Sand and Paleontological Summary

Reports of Environments of Deposition

WELL NAME AND NUMBER	LOG KEY	PALEO KEY
Port Neches Oil Orgain No. 1	1	1A
Texaco O. C. N. B. No. 2	2	2A
Texaco Kuhn No. 29	3	3A
Texaco Kuhn No. 52	4	4A
Texaco O. C. N. B. No. 9	5	5A
Texaco Polk No. B-6	6	6A
Texaco Polk No. B-31	7	7A
Texaco Polk No. B-34	8	8A

1



4202' - 4666'		Fluvial-Continental
4666' - 4715'		Brackish (Upper Bay)
4715'		Robulus chamberni
4715' - 5115'		Beach to Inner Neritic
4898'		Heterostegina zone
5115'		in Bolivina perca
5115' - 5117'		Inner Neritic to Middle Neritic
5117' - 5138'		Gap
5138' - 5140'		Beach to Inner Neritic
5140' - 5220'		Gap
5220' - 5272'		Inner Neritic
5262'		Marginulina vaginata
5272' - 5455'		Beach to Inner Neritic
5455' - 5653'		Beach-Fluvial
5653' - 5840'		Brackish

PORT NECHES PET. CORP. ORANGE COUNTY, TEXAS

#1 ORGAIN ET AL Pt. Neches Field

TEXACO PALEO LAB

1852' - 7462'	Samples available and examined
1852' - 2956'	Fluvial - Continental
3023'	Brackish
3023' - 3794'	Fluvial - Continental and Continental
3794' - 3821'	Brackish (Upper Bay)
3821' - 4081'	Continental - Fluvial
4081' - 4084'	Brackish
4084' - 4188'	Fluvial - Continental
4188' - 4202'	Brackish
4202' - 4666'	Fluvial-Continental
4666' - 4715'	Brackish (Upper Bay)
4715'	Robulus chambersi

4715' - 5115'	Beach to Inner Neritic
4898'	Heterostegina zone
5115'	in Bolivina perca
5115' - 5117'	Inner Neritic to Middle Neritic
5117' - 5138'	Gap
5138' - 5140'	Beach to Inner Neritic
5140' - 5220'	Gap
5220' - 5272'	Inner Neritic
5262'	Marginulina vaginata
5272' - 5455'	Beach to Inner Neritic
5455' - 5653'	Beach-Fluvial
5653' - 5840'	Brackish
5840'	Unconformity
5840' - 5870'	Fluvial to Beach
5870' - 6054'	Fluvial to Brackish
6054' - 6377'	Beach, Beach to Inner Neritic
6377'	Gyroidina scalata and Gyroidina soldanii and
Missing section	Ammobaculites nummus
6377' - 6930'	Outer Neritic to Slope
6930' - 7462'	Slope

7130' Sphaeroidina bulloides

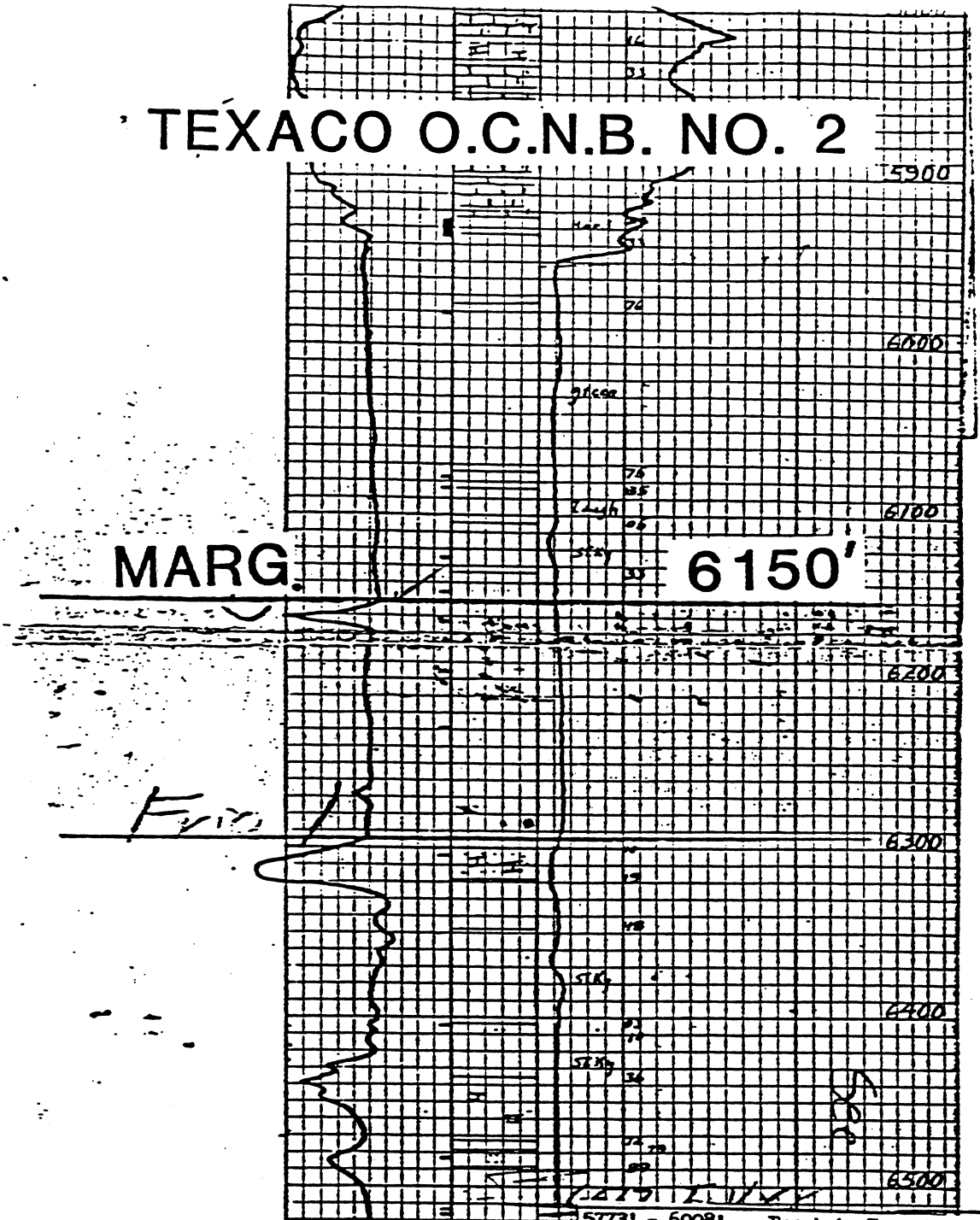
Still in Hackberry at T.D.

Sands present in samples below 6377' are probably Turbidites.

1A

TEXACO O.C.N.B. NO. 2

2



5773' - 6008'	Beach to Inner Neritic
5970'	Bolivina perca
6008' - 6077'	Inner Neritic
6008'	Marginulina idiomorpha
6066'	Marginulina vaginata
6077' - 6095'	Beach to Inner Neritic & Beach
6095' - 6155'	Inner Neritic
6155' - 6223'	Beach to Inner Neritic < Marg. Sd.
6223'	Marginulina howei
6223' - 6282'	Inner Neritic
6282' - 6488'	Beach to Inner Neritic & Beach
6371'	Textularia "D" in Frio
6403'	Poss. Unconformity
6488' - 6518'	Inner Neritic
6518' - 6548'	Middle Neritic to Outer Neritic
	Missing section here
6518'	Gyroidina scalata
6548' - 6589'	Outer Neritic
6589'	Nodosaria blanpiedi Top Pre-Hackberry
6589' - 6637'	Beach to Inner Neritic
6600'	Unconformity
6637' - 6709'	Inner Neritic
6709' - 6745'	Beach to Inner Neritic
6745'	Discorbis "D"
6745' - 6786'	Inner Neritic, Inner Neritic to Midd Neritic

TEXACO INC. ORANGE COUNTY, TEXAS

#2 ORANGE NATIONAL BANK Port Neches Field

2A

Samples from Petro-Core (Shell collection and are generally small)

PI# 00381
Encoded

3203' - 7267'	Samples available & examined
3203' - 5373'	Fluvial Cont., Fluv. Brackish mixes
5373'	Discorbis nomada
5373' - 5406'	Brackish
5406' - 5578'	Beach to Inner Neritic
5406'	Heterostegina sp.
5578' - 5685'	Beach and Beach to Inner Neritic
5578'	Unconformity
5685' - 5773'	Inner Neritic
5773' - 6008'	Beach to Inner Neritic
5970'	Bolivina perca
6008' - 6077'	Inner Neritic
6008'	Marginulina idiomorpha
6066'	Marginulina vaginata
6077' - 6095'	Beach to Inner Neritic & Beach
6095' - 6155'	Inner Neritic
6155' - 6223'	Beach to Inner Neritic
6223'	Marginulina howei
6223' - 6282'	Inner Neritic
6282' - 6488'	Beach to Inner Neritic & Beach
6371'	Textularia "D" in Frio
6403'	Poss. Unconformity
6488' - 6518'	Inner Neritic
6518' - 6548'	Middle Neritic to Outer Neritic
	Missing section here
6518'	Gyroidina scalata
6548' - 6589'	Outer Neritic
6589'	Nodosaria blanpiedi Top Pre-Hackberry
6589' - 6637'	Beach to Inner Neritic
6600'	Unconformity

TEXACO PALEO LAB

TEXACO INC. ORANGE COUNTY, TEXAS

#2 ORANGE NATIONAL BANK Port Neches Field

(Cont'd)

6637' - 6709'	Inner Neritic
6709' - 6745'	Beach to Inner Neritic
6745'	Discorbis "D"
6745' - 6786'	Inner Neritic, Inner Neritic to Middle Neritic
6786' - 7230'	Middle Neritic
6816'	Marginulina texana
6903'	Textularia mississippiensis seligsi & Cibicides pseudoungerianus
6962'	Fault
7081'	Fault
7081'	Anomalina bilateralis
7132'	Cibicides pippeni 1 sp. only Vicksburg marker found
7200'	Cibicides "10"

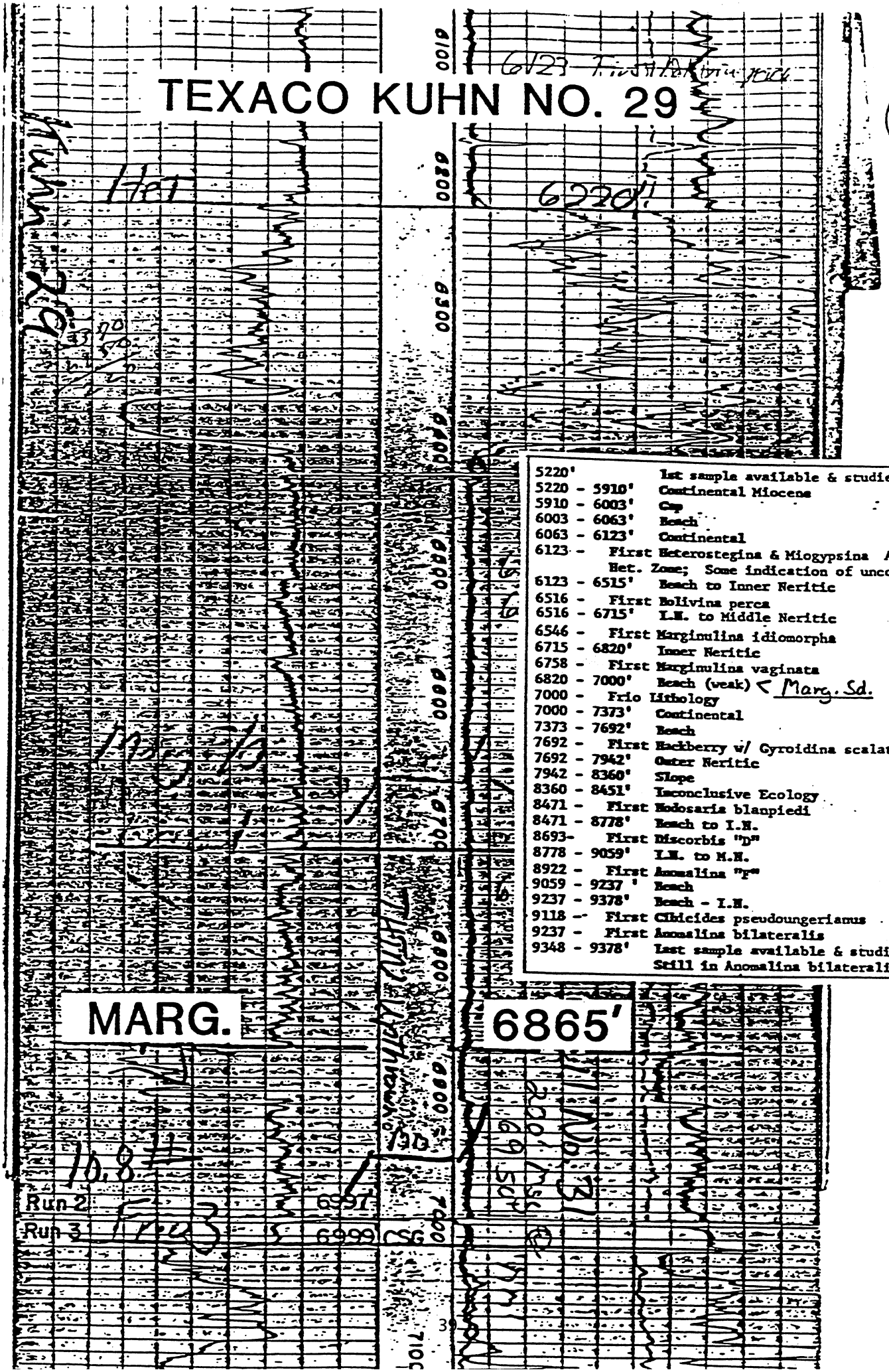
NOTE: Materials from 7081' down in this test are suggestive of Vicksburg but with the single spec. of Cibicides pippeni at 7132' we have very inconclusive marker evidence of Vicksburg.

Paleo by: C. W. Boulden
2-7-73

TEXACO GEOLOGIC LAB

TEXACO KUHN NO. 29

3



5220'	1st sample available & studied.
5220 - 5910'	Continental Miocene
5910 - 6003'	Cap
6003 - 6063'	Beach
6063 - 6123'	Continental
6123 -	First Heterostegina & Miogypsina Anahuac Het. Zone; Some indication of unconformity.
6123 - 6515'	Beach to Inner Neritic
6516 -	First Bolivina perca
6516 - 6715'	I.N. to Middle Neritic
6546 -	First Marginulina idiomorpha
6715 - 6820'	Inner Neritic
6758 -	First Marginulina vaginata
6820 - 7000'	Beach (weak) < Marg. Sd.
7000 -	Frio Lithology
7000 - 7373'	Continental
7373 - 7692'	Beach
7692 -	First Hackberry w/ Gyroidina scalata
7692 - 7942'	Outer Neritic
7942 - 8360'	Slope
8360 - 8451'	Inconclusive Ecology
8471 -	First Bodosaria blanpiedi
8471 - 8778'	Beach to I.N.
8693-	First Discorbis "D"
8778 - 9059'	I.N. to M.N.
8922 -	First Anomalina "F"
9059 - 9237 '	Beach
9237 - 9378'	Beach - I.N.
9118 --	First Cibicides pseudoungerianus
9237 -	First Anomalina bilateralis
9348 - 9378'	Last sample available & studied - Still in Anomalina bilateralis

TEXACO
#29 KUHN 42361-00371

ORANGE COUNTY

3A

Sample Range: 5220 - 9378'
Sample Source: Petro-Core
Sample Quality: Good

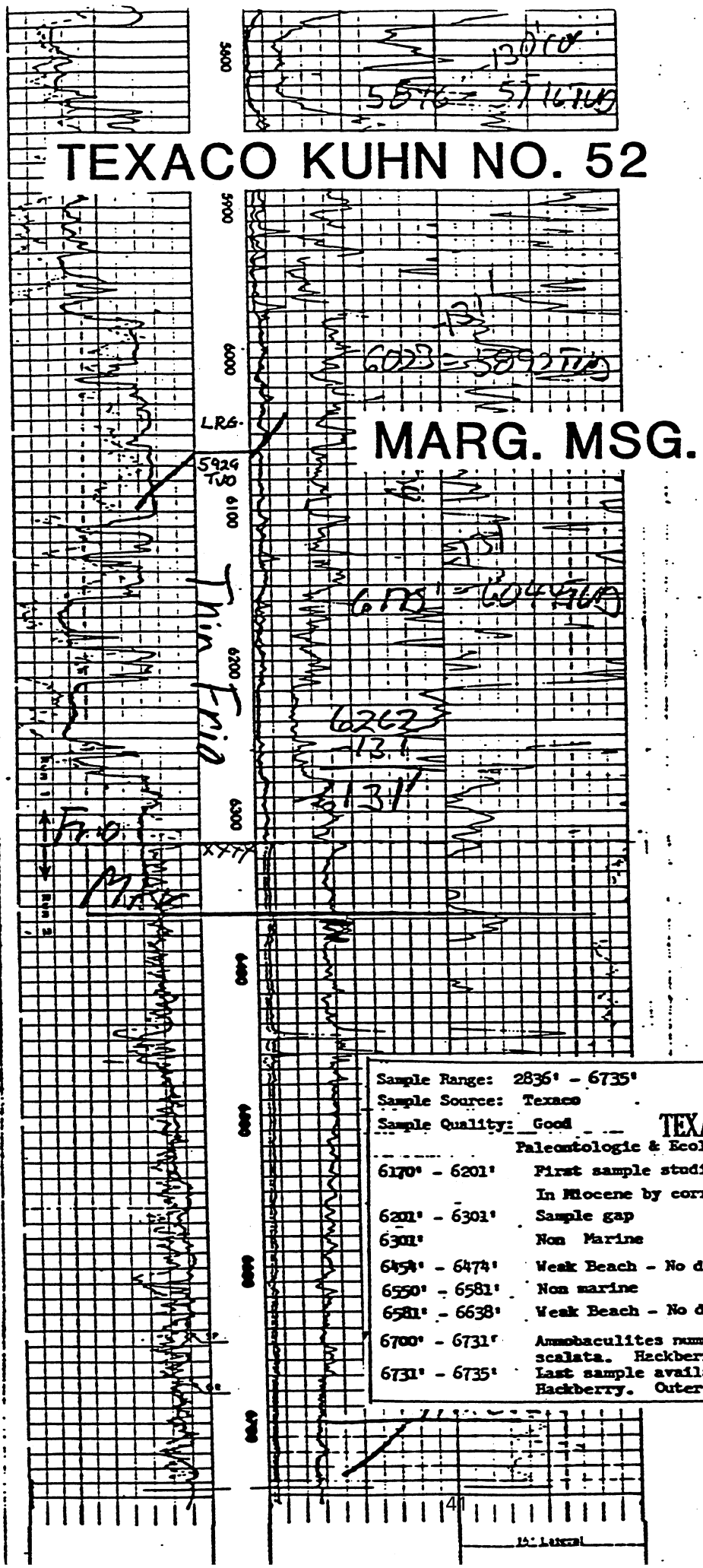
TEXACO PALEO LAB

5220'	1st sample available & studied.
5220 - 5910'	Continental Miocene
5910 - 6003'	Gap
6003 - 6063'	Beach
6063 - 6123'	Continental
6123 -	First Heterostegina & Miogypsina Anahuac Het. Zone; Some indication of unconformity.
6123 - 6515'	Beach to Inner Neritic
6516 -	First Bolivina perca
6516 - 6715'	I.N. to Middle Neritic
6546 -	First Marginulina idiomorpha
6715 - 6820'	Inner Neritic
6758 -	First Marginulina vaginata
6820 - 7000'	Beach (weak)
7000 -	Frio Lithology
7000 - 7373'	Continental
7373 - 7692'	Beach
7692 -	First Hackberry w/ Gyroidina scalata
7692 - 7942'	Outer Neritic
7942 - 8360'	Slope
8360 - 8451'	Inconclusive Ecology
8471 -	First Nodosaria blanpiedi
8471 - 8778'	Beach to I.N.
8693-	First Discorbis "D"
8778 - 9059'	I.N. to M.N.
8922 -	First Anomalina "F"
9059 - 9237'	Beach
9237 - 9378'	Beach - I.N.
9118 -	First Cibicides pseudoungerianus
9237 -	First Anomalina bilateralis
9348 - 9378'	Last sample available & studied - Still in Anomalina bilateralis

Paleo by: H. G. Walk
9-6-74

4

TEXACO KUHN NO. 52



MARG. MSG.

Sample Range: 2836' - 6735'
Sample Source: Texaco
Sample Quality: Good

TEXACO PALEO LAB

Paleontologic & Ecologic Summary

6170' - 6201'	First sample studied. Non Marine. In Miocene by correlation. <(Just below where Marg. Sd. would occur.)
6201' - 6301'	Sample gap
6301'	Non Marine
6454' - 6474'	Weak Beach - No diagnostic forms.
6550' - 6581'	Non marine
6581' - 6638'	Weak Beach - No diagnostic forms.
6700' - 6731'	Ammobaculites nummus & Gyroidina scalata. Hackberry. Outer Neritic.
6731' - 6735'	Last sample available. Still in Hackberry. Outer Neritic.

TEXACO INC. 361-30043010 ORANGE COUNTY, TEXAS

#52 KUHN SIDE TRACK #1 Pt. Neches Field

4A

Sample Range: 2836' - 6735'
Sample Source: Texaco
Sample Quality: Good

TEXACO PALEO LAB

Paleontologic & Ecologic Summary

6170' - 6201'	First sample studied. Non Marine. In Miocene by correlation.
6201' - 6301'	Sample gap
6301'	Non Marine
6454' - 6474'	Weak Beach - No diagnostic forms.
6550' - 6581'	Non marine
6581' - 6638'	Weak Beach - No diagnostic forms.
6700' - 6731'	Ammobaculites nummus & Gyroidina scalata. Hackberry. Outer Neritic.
6731' - 6735'	Last sample available. Still in Hackberry. Outer Neritic.

TEXACO INC. ORANGE COUNTY, TEXAS

#52 KUHN Pt. Neches Field

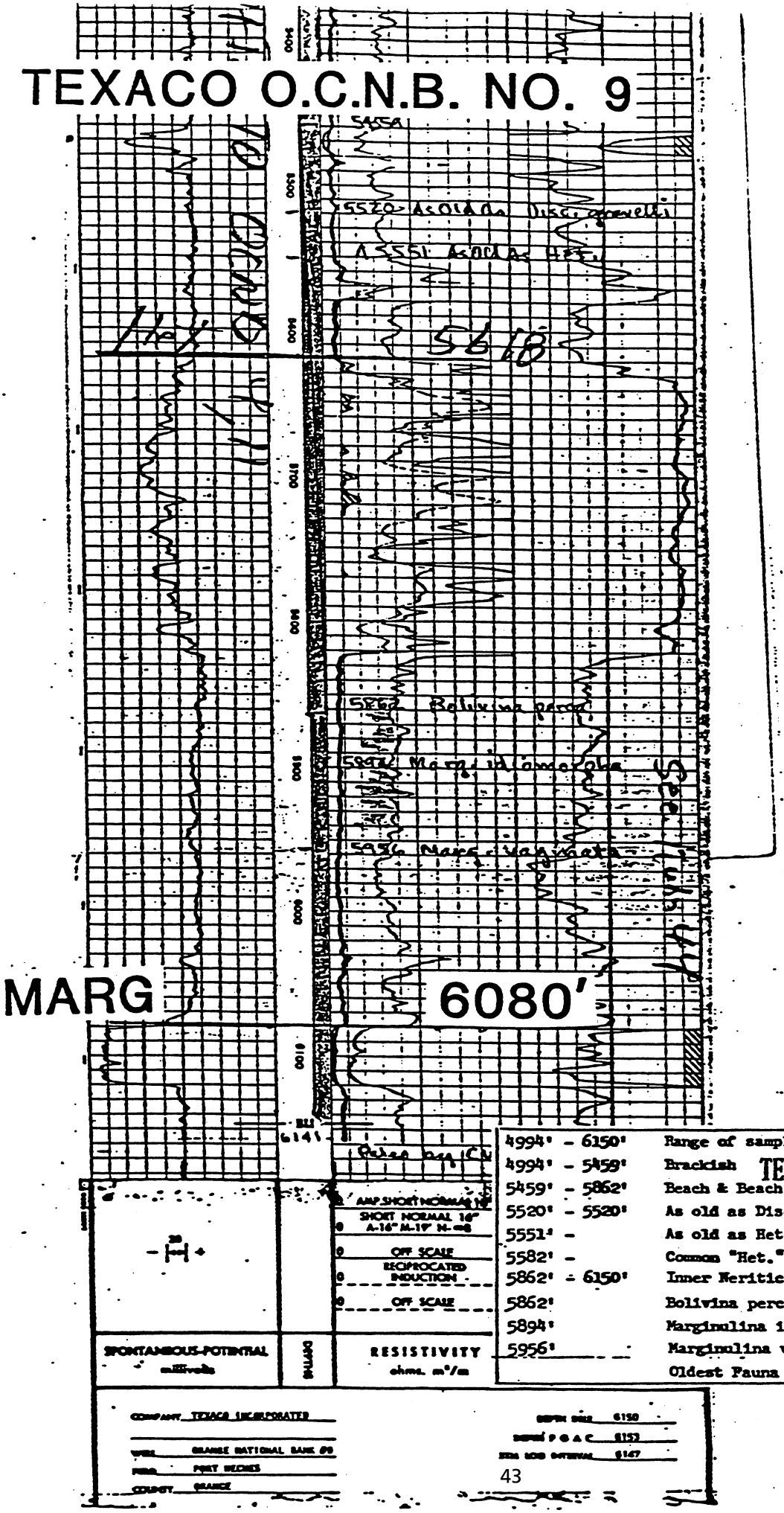
TEXACO PALEO LAB

Bottom hole check:

6170 - 6201	Medium-coarse grained frosted sub angular sand. Common white nodular lime. Very common fine grained white well sorted sand aggregates and fine grained sand with minor pyrite. Fauna few pelecypod fragments.
6201 - 6301	Sample gap.
6301 - 6331	Increase in medium-coarse grained sand as above. Common fine grained sand. Minor sand aggregates. Common white nodular lime. Pyrite.

TEXACO O.C.N.B. NO. 9

5



4994' - 6150'	Range of samples available & examined
4994' - 5459'	Brackish TEXACO PALEO LAB
5459' - 5862'	Beach & Beach to Inner Neritic
5520' - 5520'	As old as Discorbis gravelli
5551' -	As old as Heterostegina
5582' -	Common "Het." Lime
5862' - 6150'	Inner Neritic < Marg. Sd.
5862'	Bolivina perca
5894'	Marginulina idiomorpha
5956'	Marginulina vaginata
	Oldest Fauna found is Anahuac in age

8

5A

TEXACO INC. ORANGE COUNTY, TEXAS

#9 ORANGE NATIONAL BANK Pt. Neches Field

42361 21409

TEXACO PALEO LAB

4994' - 6150'	Range of samples available & examined
4994' - 5459'	Brackish
5459' - 5862'	Beach & Beach to Inner Neritic
5520' - 5520'	As old as Discorbis gravelli
5551' -	As old as Heterostegina
5582' -	Common "Het." Lime
5862' - 6150'	Inner Neritic
5862'	Bolivina perca
5894'	Marginulina idiomorpha
5956'	Marginulina vaginata
	Oldest Fauna found is Anahuac in age

Paleo by: C. W. Boulden, 12-7-72

42361 00364

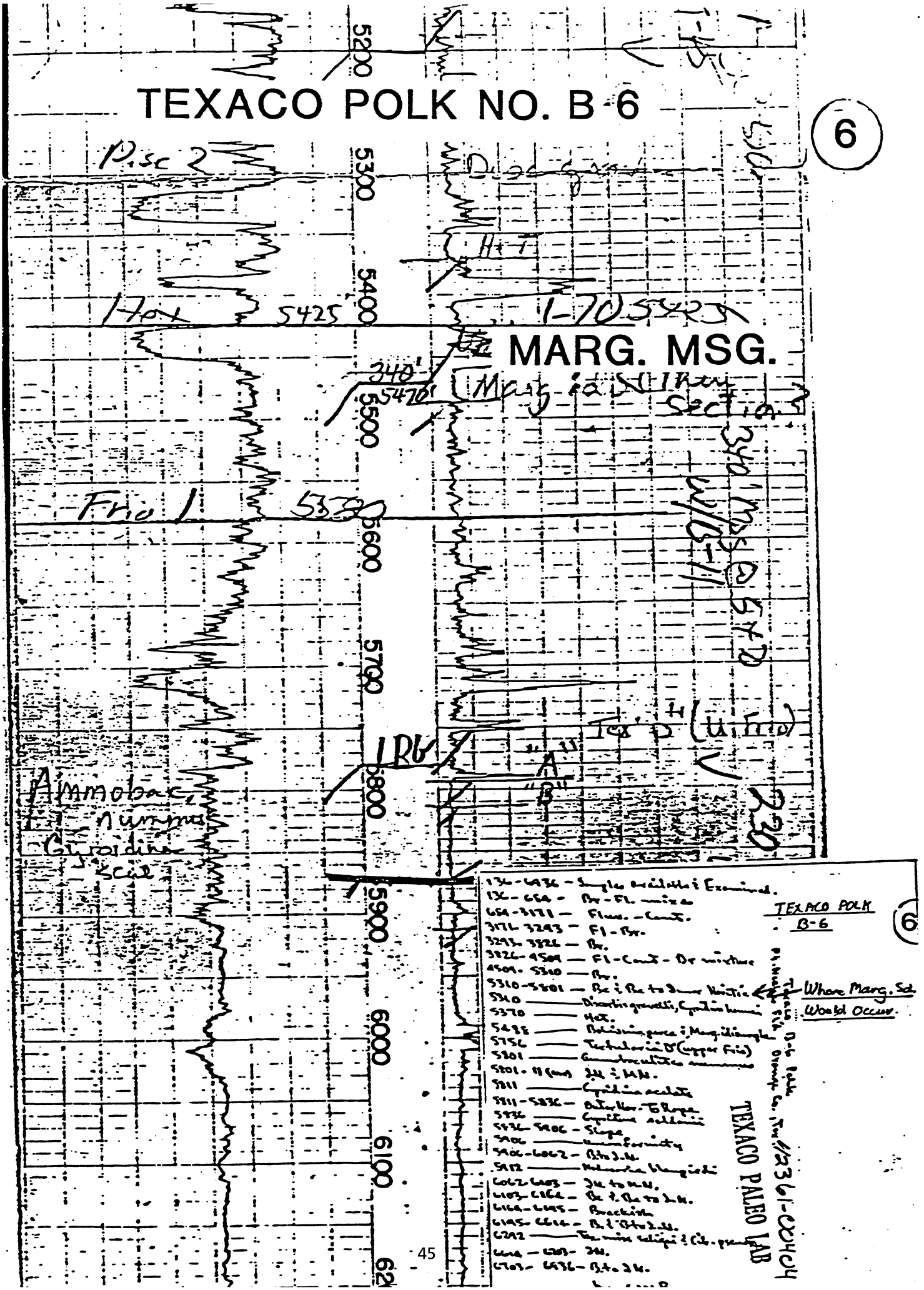
THE TEXAS COMPANY ORANGE

#5-Orange National Bank Pt. Neches

(T.T.Co.)

TEXACO PALEO LAB

Sample Range	1933-7495
First Inoceramus Prisms	3094-3125
Top of Marine Miocene	3370-3400
First Discorbis bertheloti and Siphonina davisi	5723-53 F. ANAHUAC
Top of Hackberry, Zone A	6000-30
Top of Hackberry, Zone C	6183-6213
Top of Hackberry, Zone E	6335-66
First Textularia warreni	6487-6517
T.D., D.& A. in Vicksburg	7495


TEXACO POLK NO. B-6
6
MARG. MSG.
5200
5300
5400
5500
5600
5700
5800
5900
6000
6100
Disc 2
Hex 5425
Frio 1
340'
5420'
Ammobac. nummus
Gyroidina scal
TEXACO POLK
B-6
6
Where Marg. Sd. Would Occur.
TEXACO PALEO LAB

TEXACO POLK
B-6

6A

136-6936 - Samples available & Examined.
136-684 - Br-Fl. mixes
684-3171 - Fluv.-Cont.
3171-3293 - Fl-Br.
3293-3826 - Br.
3826-4509 - Fl-Cont-Br mixture
4509-5310 - Br.
5310-5801 - Be & Be to Inner Neritic
5310 ——— Discorbis gravelli, Gyroidina hannai
5370 ——— Het.
5488 ——— Bolivina perca & Marg. idiomorpha
5756 ——— Textularia D° (upper Frio)
5801 ——— Ammobaculites nummus
5801-11 (core) IN & MN.
5811 ——— Gyroidina scalata
5811-5836 - Outer Ner. To Slope
5836 ——— Gyroidina soldanii
5836-5906 - Slope
5906 ——— Unconformity
5906-6062 - B. to I.N.
5912 ——— Nodosaria blanpiedi
6062-6103 - IN. to M.N.
6103-6164 - Be & Be to I.N.
6164-6195 - Brackish
6195-6614 - B. & B to I.N.
6292 ——— Tex. miss seligai & Cib. pseudo.
6614 - 6703 - IN.
6703 - 6936 - B. to IN.

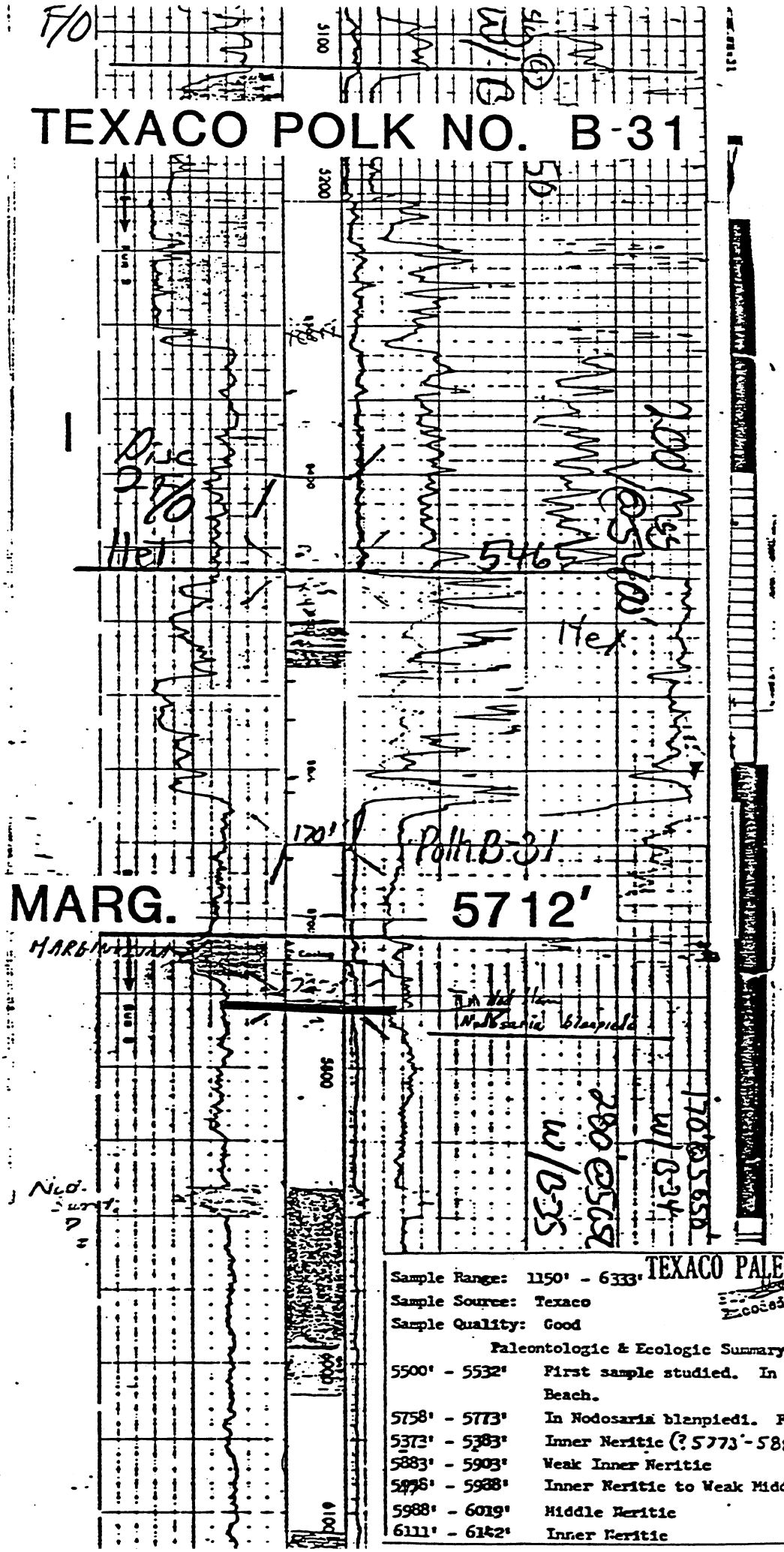
by C.W.B.
6-3-74

Texaco B-6 Polk
Pt. Niches Fld. Orange Co., Tex. 6/2361-00404

TEXACO PALEO LAB

TEXACO POLK NO. B-31

7



TEXACO PALEO LAB

Sample Range: 1150' - 6333'
Sample Source: Texaco
Sample Quality: Good

Paleontologic & Ecologic Summary

5500' - 5532'	First sample studied. In Het Zone. Beach.
5758' - 5773'	In Nodosaria blanpiedi. Prio < Marg. Sd
5773' - 5883'	Inner Neritic (? 5773' - 5883') No Zone Identified
5883' - 5903'	Weak Inner Neritic
5903' - 5988'	Inner Neritic to Weak Middle Neritic
5988' - 6019'	Middle Neritic
6111' - 6142'	Inner Neritic

TEXACO INC #236-30055 ORANGE COUNTY, TEXAS

#31-B POLK Port Neches Field 6

7A

TEXACO PALEO LAB

Sample Range: 1150' - 6333'

Sample Source: Texaco

Sample Quality: Good

Paleontologic & Ecologic Summary

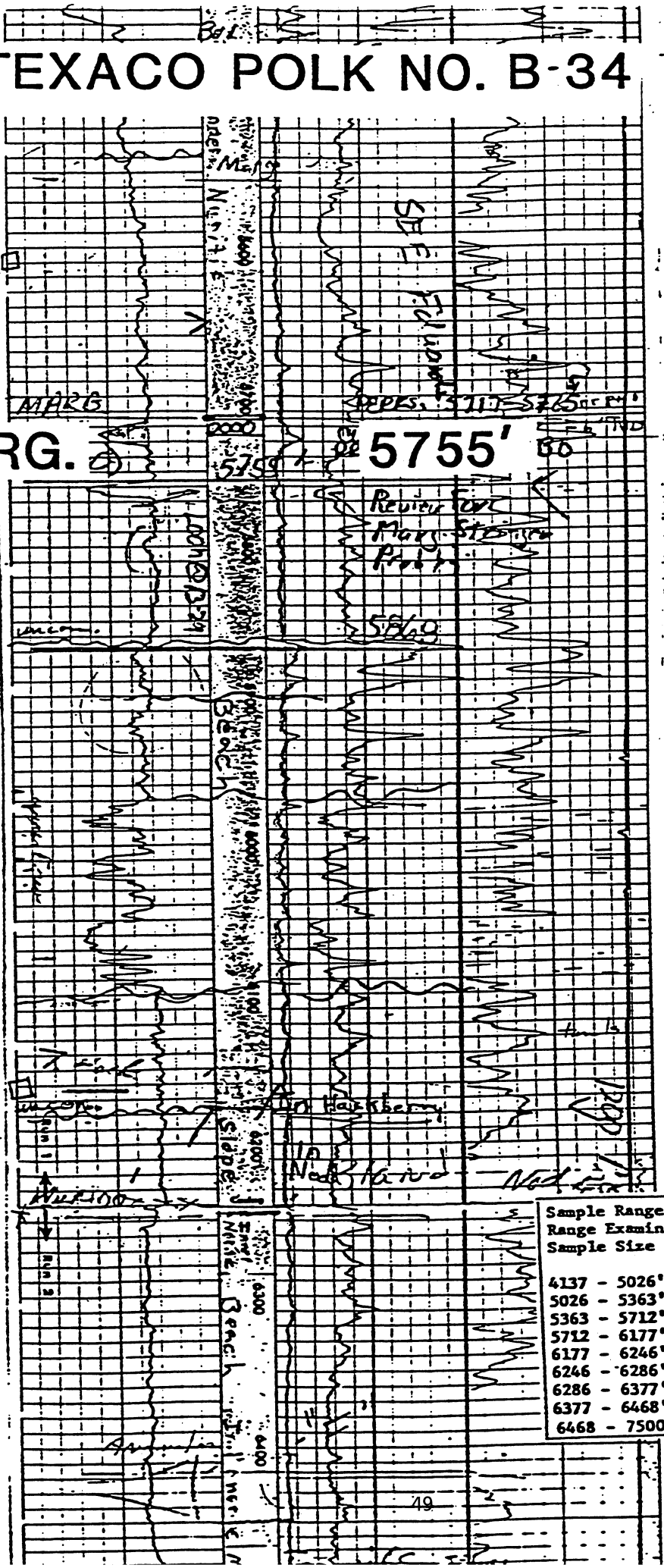
5500' - 5532'	First sample studied. In Het Zone. Beach.
5758' - 5773'	In Nodosaria blanpiedi. Frio
5373' - 5383'	Inner Neritic
5883' - 5903'	Weak Inner Neritic
5958' - 5988'	Inner Neritic to Weak Middle Neritic
5988' - 6019'	Middle Neritic
6111' - 6142'	Inner Neritic

TEXACO POLK NO. B-34

8

MARG.

5755'



Sample Range:	0-6518'	
Range Examined:	4137 - 6518'	
Sample Size & Quality:	Good	
4137 - 5026'	Bay	TEXACO
5026 - 5363'	Beach	
5363 - 5712'	Inner Neritic	
5712 - 6177'	Beach < Marg. Sd.	
6177 - 6246'	Slope	
6246 - 6286'	Inner Neritic	
6286 - 6377'	Beach	
6377 - 6468'	Inner Neritic	
6468 - 7500'	Middle Neritic	

TEXACO
#34-B POLK 361-30068 ORANGE COUNTY

8A

Sample Range: 0-6518'
Range Examined: 4137 - 6518'
Sample Size & Quality: Good

TEXACO PALEO LAB

4137 - 5026'	Bay
5026 - 5363'	Beach
5363 - 5712'	Inner Neritic
5712 - 6177'	Beach
6177 - 6246'	Slope
6246 - 6286'	Inner Neritic
6286 - 6377'	Beach
6377 - 6468'	Inner Neritic
6468 - 7500'	Middle Neritic

5214 -	Heterostegina sp.
5469	Bolivina perca
5494	Marginulina idiomorpha
5556	Marginulina vaginata
6177	Top Hackberry
6246	In Nodosaria blanpiedi
6408	Anomalina "F"
6500	Textularia mississippiensis seligi & Cibicides psudoungarianus

Paleo by: S. E. McEachern and
F. Simnacher
12-19-73

APPENDIX II

PORT NECHES FIELD

Additional Paleontological Summary

Reports of Environments of Deposition

WELL NAME AND NUMBER	PALEO KEY
Texaco O. C. N. B. No. 10	9A
Texaco O. C. N. B. No. 11	10A
Texaco Polk No. A-17	11A
Texaco Polk No. B-13	12A
Texaco Polk No. B-36	13A
Texaco Polk No. B-37 ST	14A

9A

TEXACO INC. 42361-30025 ORANGE COUNTY, TEXAS

#10 ORANGE NAT. BANK Pt. Neches Field

TEXACO PALEO LAB

2216' - 7156'	Samples available & examined
2216' - 3345'	Fluvial - Continental
3345' - 4021'	Brackish (Up-Bay) & Fluvial mixture
4021' - 4995'	Fluv. - Cont.
4995' - 5275'	Brackish Fluvial mixture
5275' - 5459'	Fluvial & Fluvial to Beach
5459' - 5552'	Beach to Inner Neritic
5459'	Siphonina davisi
5552' - 5742'	Inner Neritic
5552'	Gyroidina hannai & Discorbis gravelli
5583'	Heterostegina & Myogypsina
5742' - 5932'	Beach to Inner Neritic

5932'	Marginulina vaginata with idiomorpha
	missing section here
5932' - 6088'	Inner Neritic
6088' - 6112'	Probably Middle Neritic. 1st Gyroidina scalata
	Missing section here
6112' - 6245'	Outer Neritic
6112'	Nodosaria blanpiedi & Ammobaculites nummus
	Poss. remnant of Hackberry here
6245' - 7156'	Middle Neritic
6275'	Anomalina "F"
6307'	Anomalina bilateralis with Textularia mississippiensis
	Missing section here
6396'	Textularia warreni (as old as)
	Note: Most of Anomalina bilateralis to and including upper Textularia warreni section is missing
6678'	Loxostoma "B" (as old as) most of Lox. "B" section missing

TEXACO INC. ORANGE COUNTY, TEXAS

#10 ORANGE NAT. BANK Pt. Neches Field

(cont'd)

TEXACO PALEO LAB

6707'	Cibicides pippeni zone.
	In Cibicides pippeni at T.D.

Paleo by: C. W. Boulden

1-15-73

10A

TEXACO INC. 42361-300 ORANGE COUNTY DPT 4

#11 ORANGE NATIONAL BANK Pt. Neches Field

TEXACO PALEO LAB

4686 - 6593	Sample Range
4686 - 5872	Bay
5872 - 6057	Beach & Beach to Inner Neritic
5995	Siphonina davisi
6057 - 6212	Skip in samples
6057 - 6264	Inner Neritic
6212	Het and Miogypsina
6264 - 6500	Outer Neritic
6264	Ammoboculites nummus
	First Hackberry fauna
6500 - 6593	Slope

* Missing section is evident at 6350' where Het. Lime overlies Hackberry.

Paleo by: C. W. Boulden
1-19-72

Selestan
Scalvan
[illegible]

A-132

TEXACO INC. 361_ 01427 0001 Orange County DPT 11
#17 J. V. Polk "A" NCT-1 Port Neches Field

6

11A

Sample Range Examined: 5500-8400
Sample Quality Good Throughout Well

5500-5532	In Miocene
5627-5659	First Discorbis sp (Oligocene)
5753-5784	First Eponides ellisorae
5879	First Heterostegina sp
5943-5974	Faulted
5974-6005	In Frio (lithology)
6287-6318	Marginulina texana
6318-6349	First Ammobaculities nummus (Hackberry)
7571-7602	First Nonion struma
7748-7980	Samples Not Representative
7980-8000	First Nodosaria blanpiedi (low)
8124-8145	Gap in Samples

TEXACO INC. #17 J. V. Polk "A" NCT-1 Orange Co.

8145-8177	In Discorbis "D"
8373-8400	Last sample-Still Discorbis "D"

Paleoecology Summary

TEXACO PALEO LAB

5500-5565	Continental
5565-5879	Ecology Zone 1
5879-5911	Ecology Zone 2
5911-5974	Ecology Zone 2+
5974-6349	Ecology Zone 3
6349-6475	Ecology Zone 4+
6475-7057	Ecology Zone 5
7057-8400 TD	Ecology Zone 3

E. H. Stork, Jr.
2-16-67

B

12A

TEXACO INC. ORANGE COUNTY, TEXAS

#13-B POLK **TEXACO PALEO LAB** Port Neches Field

Sample Range: 4986' - 5961'

Sample Source: Petro-Core (Shell) 42300407 Encoded

Sample Quality: Fair (Excessive Sand)

Paleontologic Summary

5016' - 5046'	First sample studied. In Non marine Miocene.
5292' - 5372'	First Marine Miocene.
5446' - 5476'	In Anahuac. As old as Marginulina vaginata.
5630' - 5660'	In Frio w/Cibicides hazzardi.
5753' - 5784'	In Hackberry. Ammobaculites nummus.
5784' - 5815'	Sphaeroidina sp.

5886' - 5901'	Nodosaria blanpiedi (Probably reworked) Still in Hackberry.
5916' - 5965'	Indefinite, elements of Hackberry fauna present with possibly in place Nodosaria blanpiedi. Could be interpreted as Hackberry with N. blanpiedi slumpage or true N. blanpiedi Frio.
5946' - 5985'	Last sample.

Paleo by: H. G. Walk
1-31-73

Texaco
#13 B Polk

00407

Orange County
Port Neches Field

TEXACO PALEO LAB

4986 - 5961	Samples available & examined
4986 - 5322	Brackish, B to Fluv., & Br to Beach
5322 -	Marginulina idiomorpha with Bolivina perca & Disc. aprovelli
5446	Marginulina vaginata
5476 - 5661	Inner Neritic
5661 - 5784	B to IN
5753	Ammoboculites nummus
5784 - 5886	IN
5886	Nodosoria blanpiedi
5886 - 5916	IN with Slope mix (Fallin Hackberry)
5916 - 5961	B to IN with Hackberry fallin *IN Nadosonia blanpiedi

TEXACO 42361- 30078 ORANGE COUNTY DPT/5
#36-B POLK

13A

4765 - 5132'	Non-marine; Continental to Brackish
5162 - 5224'	Weak Beach; No diagenetic fauna; Miocene
5224 - 5255'	1st Robulus chambersi; Beach
5255 - 5287'	1st Discorbis "B"; Beach-Inner Neritic
5287 - 5599'	1st Heterostegina; Beach
5599 - 5638'	1st Hackberry fauna w/ Gyroidina soldani, Gyroidina scalata; Sphaeroidina bulloides (Hackberry fauna rare, worn, probably reworked)
5638'	Salt water flow
5736 - 5766'	1st Nodosaria blanpiedi; I.N.
6270 - 6291'	1st Anomalina "F"; I.N. to Middle Neritic
6322 -	T.D.; Still in Anom. "F"

Paleo by: H.G.Walk
May, 1974

TEXACO GEOLOGIC LAB

TEXACO ORANGE COUNTY DPT/6
#37-B POLK #1 Sidetrack 42361- 30087-000

4A

Sample range: 0 - 6000'
Range examined: 5434' - 6000'
Sample size and quality: Good

5810 - 5829'	Gyrodina scalata
5434 - 5556'	Brackish - Beach
5556 - 5619'	Beach
5619 - 5645'	Brackish
5645 - 5810''	Beach
5810 - 5902'	Inner Neritic
5902 - 6000'	Inner Neritic - Middle Neritic

Paleo by: K. M. Campion
8-8-74

TEXACO GEOLOGIC LAB

RESERVOIR SIMULATION OF PORT NECHES (MARG AREA 1) RESERVOIR

TEXACO E & P INC.

SOUR LAKE AREA

"PORT NECHES FIELD"

"RESERVOIR SIMULATION OF PORT NECHES (MARG AREA 1) RESERVOIR"

PREPARED BY DARRELL W. DAVIS

JANUARY, 1993

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Port Neches Field CO_2 Project
Reservoir Simulation

Summary

The Scientific Software Intercomp (SSI) Comp III model was used to simulate the primary and secondary production history of the Port Neches (Marg Area 1) reservoir and to predict the recoveries which can be obtained by CO_2 flooding the reservoir. An original oil-in-place (OOIP) of 10.4 MMSTBO was found to exist in the reservoir at discovery in 1934, with 4.42 BCF solution gas. A weak aquifer influx occurring from two different locations within the reservoir, was incapable of supporting the withdrawal rates which occurred in the first year of production, thus dropping the reservoir below the bubble point pressure early in the life of the reservoir. Gas cap expansion and a reduction in reservoir pressure from 2700 psi to 100 psi, allowed for a primary recovery of 41% OOIP (4.3 MMSTBO) through 1965. A waterflood initiated at that time has allowed for an additional 13.5% OOIP (1.4 MMSTBO) to be produced from the reservoir with a 75% HCPV water injection. The Comp III simulation model predicts that an additional 0.8 MMSTBO (8% OOIP) can be recovered by continued waterflood operations. If CO_2 is initiated, not only will this 8% OOIP secondary reserve be recovered, but an additional 2.0 MMSTBO (19% OOIP) can be recovered from this reservoir by applying a continuous CO_2 tertiary injection process. Approximately 7.3 BCF (3.7 MCF/BO) of CO_2 will be purchased and a total of 33.3 BCF of CO_2 (16.7 MCF/BO) will be injected in order to recover this 2.0 MMSTBO of tertiary oil.

Introduction

The Port Neches CO_2 Project will begin CO_2 injection during 1993 into the Marginulina sandstone reservoir at a depth of 5900 feet. Two fault blocks will be flooded during the 15 year project life of this CO_2 project, with initial focus upon a 235 acre fault block of the sand which has been waterflooded since 1965. This large fault block has been separated into a new field designation known as the Port Neches (Marg Area 1) to allow for unitization of royalty owners to take place. A compositional reservoir simulation model has been developed for this fault block to predict the recoveries which can be achieved by the utilization of continuous CO_2 injection. This study was conducted over the time period of August, 1991 thru May, 1992, and is the first attempt to simulate this reservoir's performance. The conclusions developed from this study have assisted in the design of this project, and point out some future work which needs to be done to improve the model.

This project's SSI Comp III simulation model utilizes a 20X30X2 grid system, 270' in the X direction and 219' in the Y direction. The thickness of the sand was modeled using the SSI workbench program, inputting sand thickness of each well, and allowing the program to generate the thickness array. This sand thickness was then split in half to allow for a two layer model to be constructed. A Dykstra Parson's coefficient of 0.5 was utilized to distribute permeabilities to these layers using an average permeability of 750 md. Permeabilities of 420 md and 1080 md were

used in both the X and Y direction, in the top and bottom layers respectively, with the vertical permeabilities being 10% of each of these values. A constant porosity of 30% was utilized across the entire grid. Two inactive cells were placed in the grid to reflect a small area of the reservoir around H. J. Kuhn Tr. 1 Well No. 9 where the sand is missing.

The relative permeability data for this Gulf Coast sandstone was developed by utilizing correlations[1]. The following criteria were used to obtain the data:

$S_{wir} = S_i = 20\%$
$S_{orw} = 20\%$
$S_{gr} = 2\%$
$N = 2.0$ (Corey Exponent)

These values are typical of Gulf Coast sandstones yet will be confirmed by conventional core data to be obtained during 1993. Corrections to the calculated values were made to assist in the history match of the reservoir.

To define the CO_2-hydrocarbon interaction coefficients used in the compositional simulator, stock tank oil[2] and live oil[3] samples had swelling/solubility measurements made for various CO_2 and oil mixtures, at various concentrations of CO_2. This laboratory measured fluid data was then used in the Comp III PVT program to fine tune the equation of state. The equation of state chosen for this study was the Zudkevitch-Joffe Redlich-Kwong (ZJRK) equation. Reservoir properties associated with the simulation model are as follows:

Oil Gravity	=	38° API
Initial Reservoir Pressure	=	2764 psia
Bubble Point Pressure	=	2660 psia
Solution Gas/Oil Ratio	=	424 SCF/STB
Reservoir Temperature	=	165° F
Acreage	=	235 acres
Average Net Pay	=	29.2 ft
Average Porosity	=	30 %
Average Permeability	=	750 md
Formation Volume Factor	=	1.23 RB/STB
Oil/Water Contact (subsea)	=	5988 ft

Primary/Secondary History Match

The primary and secondary history match of the Port Neches (Marg Area 1) reservoir used the best available data present to characterize the reservoir, yet this data was very limited. No conventional cores exist for this 64 year old field, and few sidewall cores were taken in the Marginulina sand in the project area. Limited openhole and cased hole porosity (CNL,FDC,Acoustic) logs exist for this same area of concentration, therefore supporting the use of uniform rock properties in the reservoir. Assumptions had to be made upon the properties of the reservoir fluid as well, as there were no PVT data available for the original

reservoir fluid. The bubble point pressure and solution gas/oil ratio were estimated based upon actual field performance. It is felt that these assumptions are consistent with industry practices.

A first check as to the validity of the model centered around the original oil-in-place calculated. With sand thickness for each grid generated by the SSI workbench program using known sand thickness data, the reservoir volume is representative of the actual volume present. An oil/water contact of 5988' evidenced by the electric log of the J. V. Polk "A" No. 5, and actual water production obtained upon initial testing of the well, supports the hydrocarbon bearing reservoir volume used. With this data entered the program calculated an original oil-in-place of 10.4 MMSTBO, a volume which closely matches that calculated by Texaco's Oilwat[4] material balance program.

Modeling of the gas production from the reservoir confirmed the presence of a permeability barrier or nonsealing fault at the location of H. J. Kuhn No. 9. In order to match the early gas production obtained from the J. V. Polk "B" No. 2 and the H. J. Kuhn No. 6 discovery wells, two inactive cells were placed around the H. J. Kuhn No. 9, with reduced sand thickness surrounding these cells. This allowed the area around these wells to act as a small reservoir, allowing the reservoir pressure to drop below the bubble point pressure quickly, thus creating a high gas saturation around the wells. Adjustments to the gas/oil relative permeability curve would not allow for this early gas production to occur without the sacrifice of oil production. With this reservoir initially being mapped with a fault running through the H. J. Kuhn No. 9 location, this possibility must still be evaluated as new geological data is obtained in the field.

The oil production for each well was entered as an input to the program, with associated water and gas production generated by the reservoir model. Oil production matched historical volumes throughout the primary phase of depletion but began to fall short after the initiation of the waterflood. Wells became incapable of producing the required amounts of oil due to pressure constraints, thus resulting in the predicted cumulative oil being 2.5% less than the actual. The oil/water relative permeability curve was adjusted in an attempt to compensate for this shortfall, thinking that excessive water production was maintaining the reservoir pressure at low levels of 181 psi. This adjustment did not correct the problem however, thus indicating that the problem lies in the magnitude of the aquifer strengths.

While modeling the Port Neches (Marg Area 1) reservoir, it became apparent that the reservoir is acted upon by two distinct aquifers. A large aquifer to the west was known to be present due to the water encroachment over time on the W. H. Stark "B" and H. J. Kuhn Tr. 1 leases. Water production from the J. V. Polk "B" No. 2 and the H. J. Kuhn No. 6 occurred over a period of time that cannot be explained without the introduction of an additional aquifer to the east. The model results of oil, water, and reservoir pressure

indicates that the strengths of these aquifers must be further adjusted in order to improve the reservoir history match. An increase in strength of the aquifer acting upon the H. J. Kuhn and W. H. Stark "B" leases and a decrease in strength of the aquifer acting upon the J. V. Polk "B" lease, will improve the match. By making these changes, the oil/water relative permeability curve can be adjusted back to values more indicative of those obtained by correlations. The proper balance of aquifer strength and oil/water relative permeability curves can best be accomplished once conventional core data is obtained. The model results obtained by using this history match does justify the use of CO_2 flooding over continued waterflood operations, however the remaining oil saturation distribution within the reservoir, and resulting production rate by well, cannot be fully supported. Future work will improve the confidence level of this prediction.

Waterflood Performance

After obtaining a primary and secondary history match of the reservoir, the compositional model was used to predict the remaining oil which could be recovered by continued waterflood operations. Water injection into the H. J. Kuhn No. 17 and the W. H. Stark "B" No. 10 was maintained over a 15.5 year period, with production established in the same wells planned as producers in the CO_2 flood. Though current production levels are representative of the model's prediction of 70 BOPD, 1176 BWPD, and 1 MCFPD for 1993, the initiation of production from the H. J. Kuhn No. 14, a well which has been shut-in since the 1960's, drastically impacts the remaining secondary recoverable reserves for the reservoir. As can be seen in Figure E-5, the model predicts that a low water saturation exists around this well, thus resulting in a high oil production rate of 295 BOPD, 58 BWPD, and 12 MCFPD when production from the well is established. With high production rates established by this well, and somewhat higher oil cuts on currently producing wells due the oil/water relative permeability curve utilized, the model predicts that an additional 0.8 MMSTBO can be recovered over a 15.5 year life by continued waterflood operations. This total secondary recovery of 2.2 MMSTBO, or 21% OOIP, is felt to be high due to the oil/water relative permeability curve used in the model and a small error in the magnitude of the aquifer strengths. Adjustments to this curve and to the aquifer strengths within the reservoir will improve the results of the model in future work.

CO_2 Flood Performance

A CO_2 flood utilizing 5 injection wells (2 wells to represent a horizontal CO_2 injector) and 8 producing wells recover 2.8 MMSTBO or 27% OOIP over a 15.5 year life on the compositional simulator. The predicted incremental tertiary oil reserve for this Port Neches (Marg Area 1) reservoir is therefore 2.0 MMSTBO or 19% OOIP, the recovery above that of waterflood recovery. Figure D-1 shows how the CO_2 flood versus continued waterflood curves compare, both curves being affected greatly in 1993 by the high oil production rate of H. J. Kuhn No. 14. Figures F-4 thru F-7 show the movement of the CO_2 front through the reservoir, increasing the gas (CO_2)

saturation in the grid cells. A final production rate of 126 BOPD, 73 BWPD, and 14450 MCFPD occurs in the model when it is stopped in the year 2008.

Due to the recommended adjustments to the model recognized by this study, a more conservative production forecast was utilized for Texaco's economic evaluation of the project. A peak production rate of 792 BOPD is anticipated during 1994, 350 BOPD below the model's peak production rate of 1142 BOPD obtained in 1995. The model verified early CO_2 gas breakthrough to the producing wells, a factor which is critical to CO_2 flooding economics, with wells producing 4.7 MMCFPD of CO_2 at the end of 1994.

Conclusions

1. The results of the primary and secondary history match indicates that 10.4 MMSTBO existed in the 235 acre fault block of the Marginulina reservoir at discovery. A comparison of actual versus model predicted production is as follows:

Date		MBO	MBW	MMCF
1/1/69	Actual	4491	1997	4222
	Model	4476	1828	4386
	Variance	(0.3%)	(8.5%)	3.9%
1/1/91	Actual	5684	8980	4434
	Model	5545	7592	4516
	Variance	(2.5%)	(15.5%)	1.9%

2. The model's prediction of current reservoir pressure is off by 1800 psi (3650 psi versus the actual pressure of 1850 psi) due to inadequate water production from wells on the H. J. Kuhn and W. H. Stark "B" leases. The aquifer acting upon these leases is stronger than 0.0025 RB/psi-day for each grid block it acts upon. It is seen that the aquifer acting upon the Polk "B" lease is actually weaker than predicted, therefore explaining the increased water production on this side of the field.

3. Models are very dependant upon the reservoir characterization utilized. Aquifer strengths must be altered when layer permeabilities are changed. Given the same average permeability for a one layer and a two layer model, the Dykstra Parson's coefficient applied to the two layer model yields a permeability distribution which acts differently than a one layer constant permeability model, thus requiring that the aquifer strengths be changed in order to obtain a history match.

4. The remaining secondary and tertiary production forecast is impacted greatly by the high oil saturation predicted around H. J. Kuhn Well No. 14. This well is predicted to be capable of producing 295 BOPD without CO_2 injection. Higher water saturations in the area of this well will yield lower initial rates.

5. The oil/water relative permeability curve and aquifer strength coefficients must be altered in order to improve upon the history match and future predictions.

6. An incremental tertiary oil recovery of 2.0 MMSTBO (19% OOIP) is consistant with the predictions of the modified DOE CO_2PM^5 program used for project economic evaluations.

Future Work

The results obtained from this compositional model bring out several areas of future work which must be concentrated on in order to improve the history match of primary and secondary production and the performance of CO_2 injection. The geological reservoir characterization will be improved by obtaining a conventional core on the W. H. Stark "B" No. 10 in order to establish the true absolute and relative permeability distributions within the rock. Residual oil saturation to waterflood will be measured, and a possible CO_2 core flood may be conducted to determine the residual oil saturation to CO_2. The effects of overburden pressure upon the permeability will be investigated, and porosity and vertical permeability measurements will be made. Texaco's possible 3-D seismic program will assist in the interpretation of faulting which occurs within the reservoir, thus improving the structural interpretation.

Adjustments to the aquifer strength will be performed as discussed, in order to improve the reservoir pressure and water production history match. This will allow for improved confidence in the saturation distribution within the reservoir. Productivity indices will be calculated on producing wells by running producing bottomhole pressure surveys and measuring actual fluid production. The actual oil percentages on produced fluid from these wells will be compared to the relative permeability predictions, thus indicating the saturation distribution within the reservoir around each individual well.

Acknowledgements

I would thank the individuals at Texaco EPTD for their work on this project. I would especially like to recognize Charles Cheng of EPTD for his assistance in the development of an equation of state for the reservoir oil and his insight into compositional simulation. Dexter Williams of the Harvey CO_2 group should also be recognized for his computer support. Thanks to the Department of Energy for selecting this project in their Class I Oil Program.

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3. Widener, M. W. and Vu, T. M.: Phase II - CO_2 Swelling/ Solubility Studies For Reservoir Fluids of the Port Neches Field, H. J. Kuhn No. 33 Well, Orange County, Texas. (Texaco EPTD Report No. 92-015)

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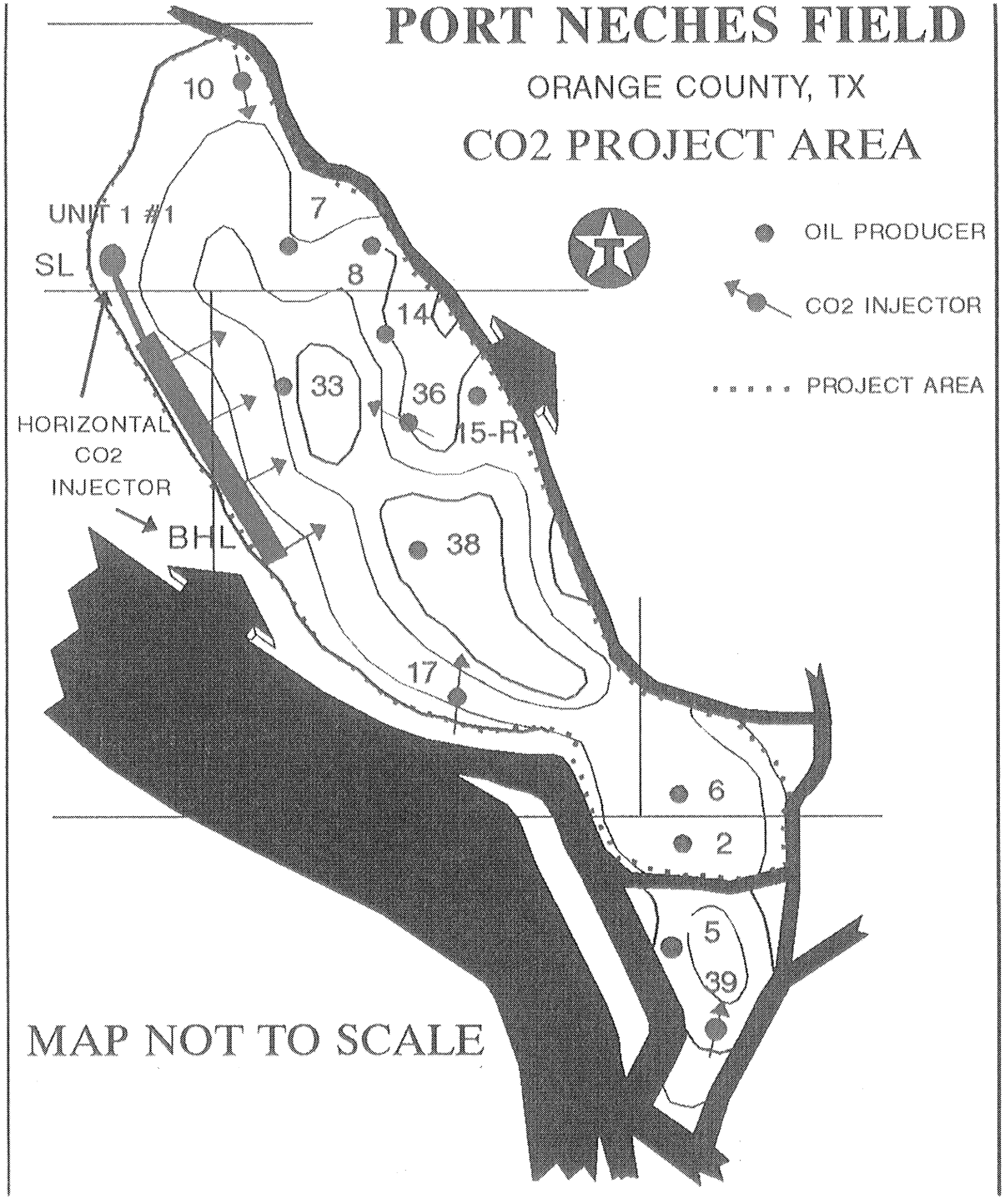
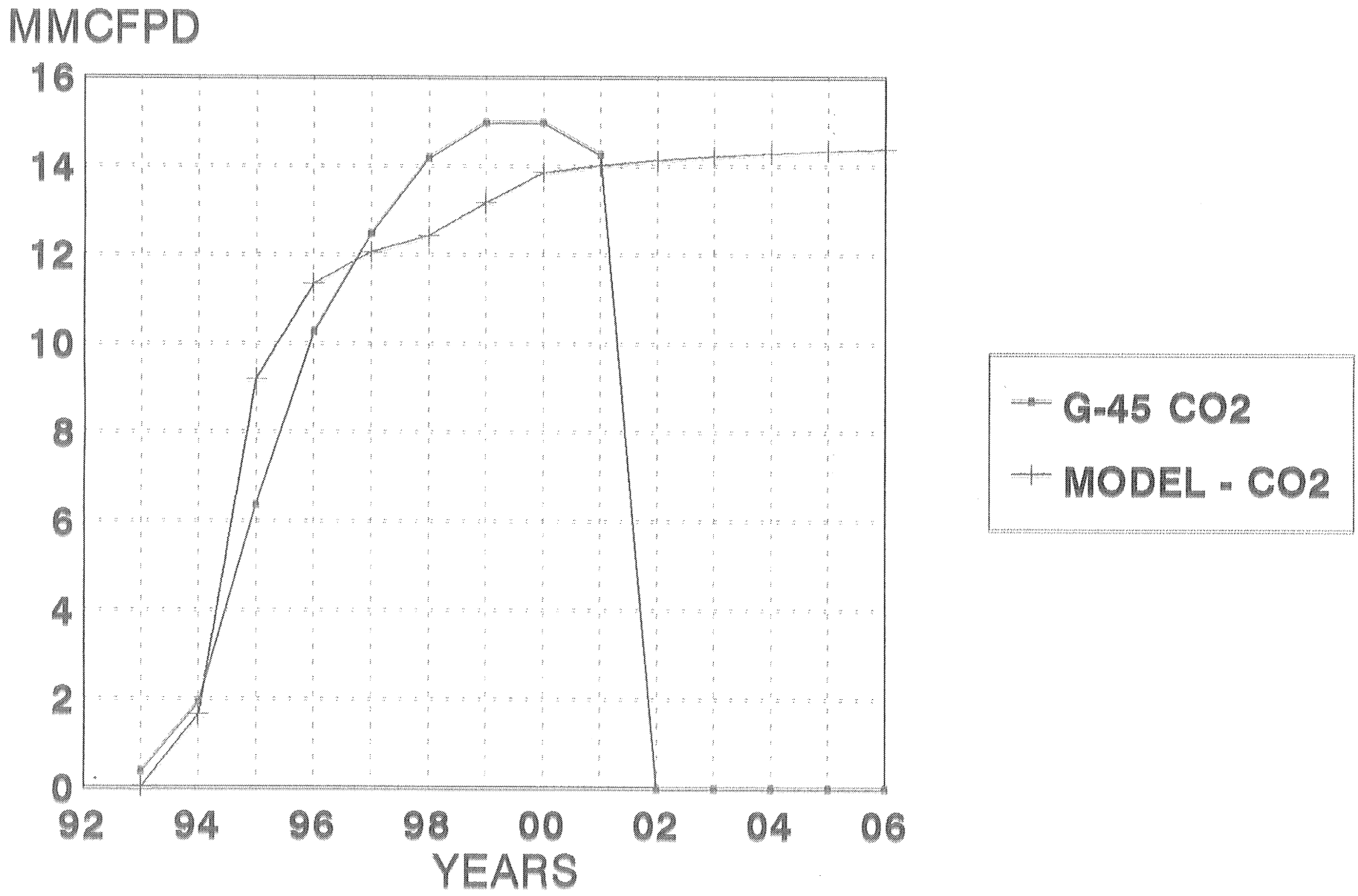
5. DOE/BC/10327-20, Scientific Software-Intercomp: Development and Verification of Simplified Prediction Models for Enhanced Oil Recovery Application. CO_2 (Miscible Flood) Predictive Model - Final Report, (Oct. 1984). Modified by Alston, R. B. et al (Texaco EPTD)

DWD\PN\RESSIM


PORT NECHES FIELD
ORANGE COUNTY, TX
CO2 PROJECT AREA
OIL PRODUCER
CO2 INJECTOR
PROJECT AREA
UNIT 1 #1
SL
HORIZONTAL
CO2
INJECTOR
BHL
10
7
8
14
33
36
15-R
38
17
6
2
5
39
MAP NOT TO SCALE

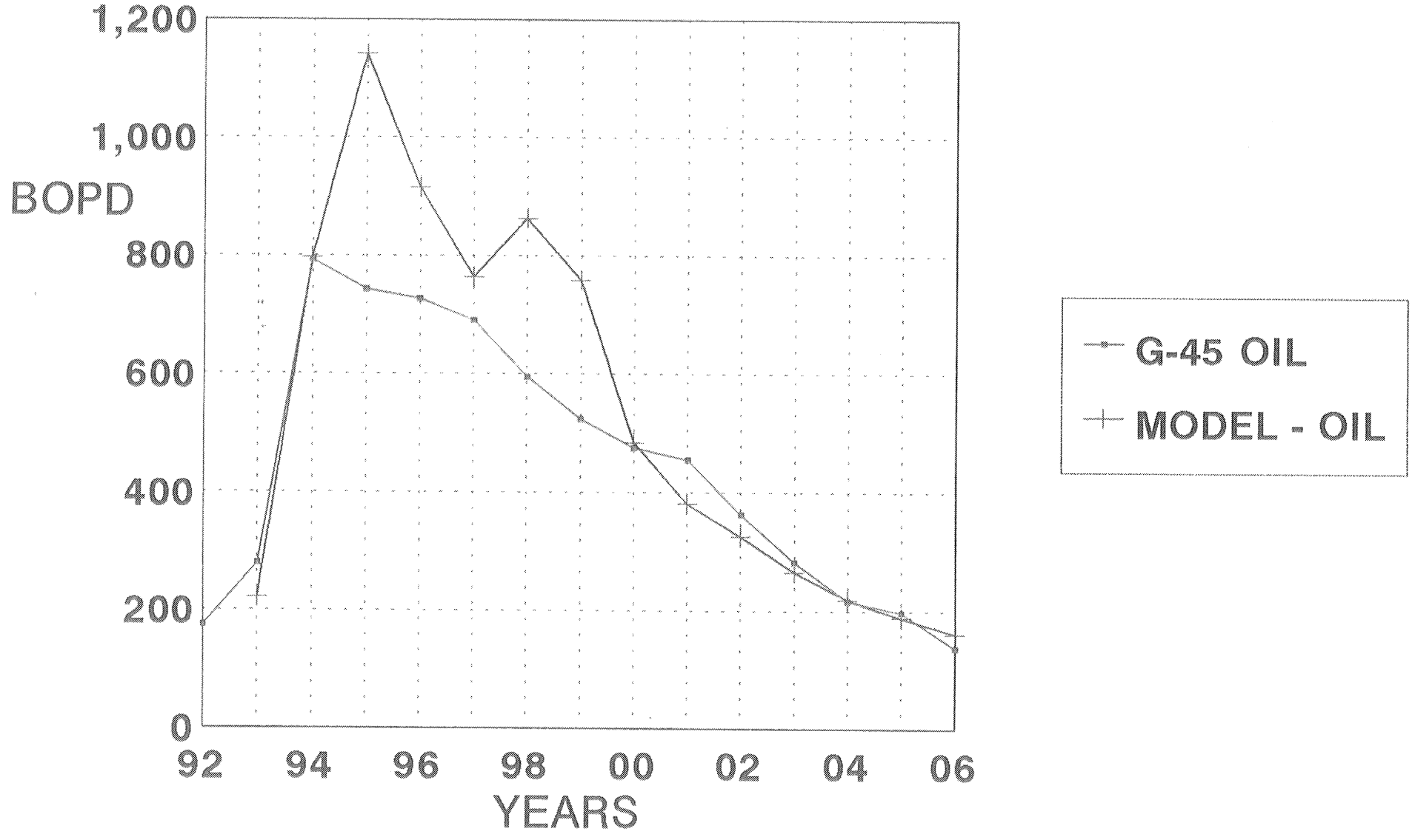
Port Neches CO2 Flood

CO2 Production Forecasts

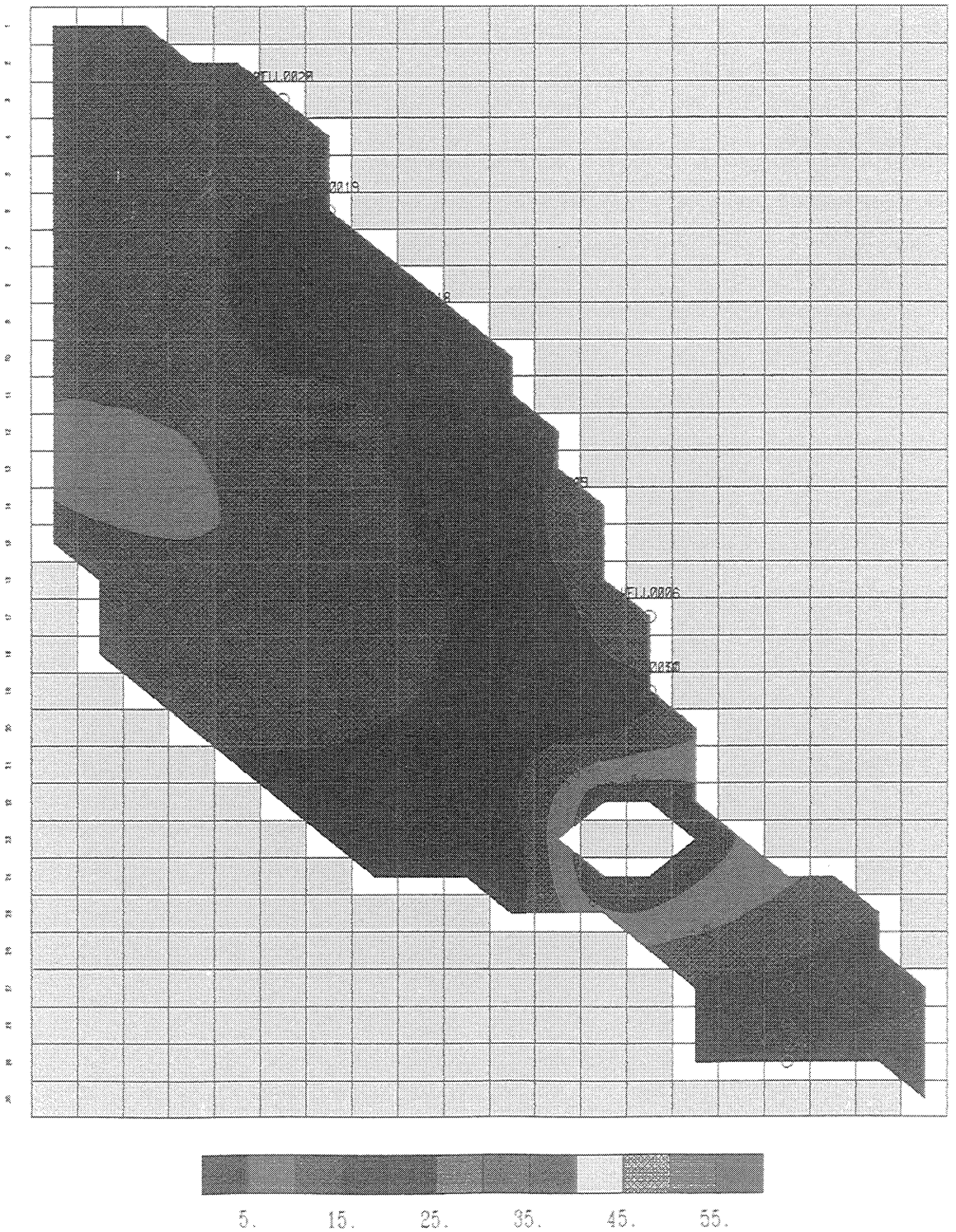


Port Neches CO2 Flood

Oil Production Forecasts

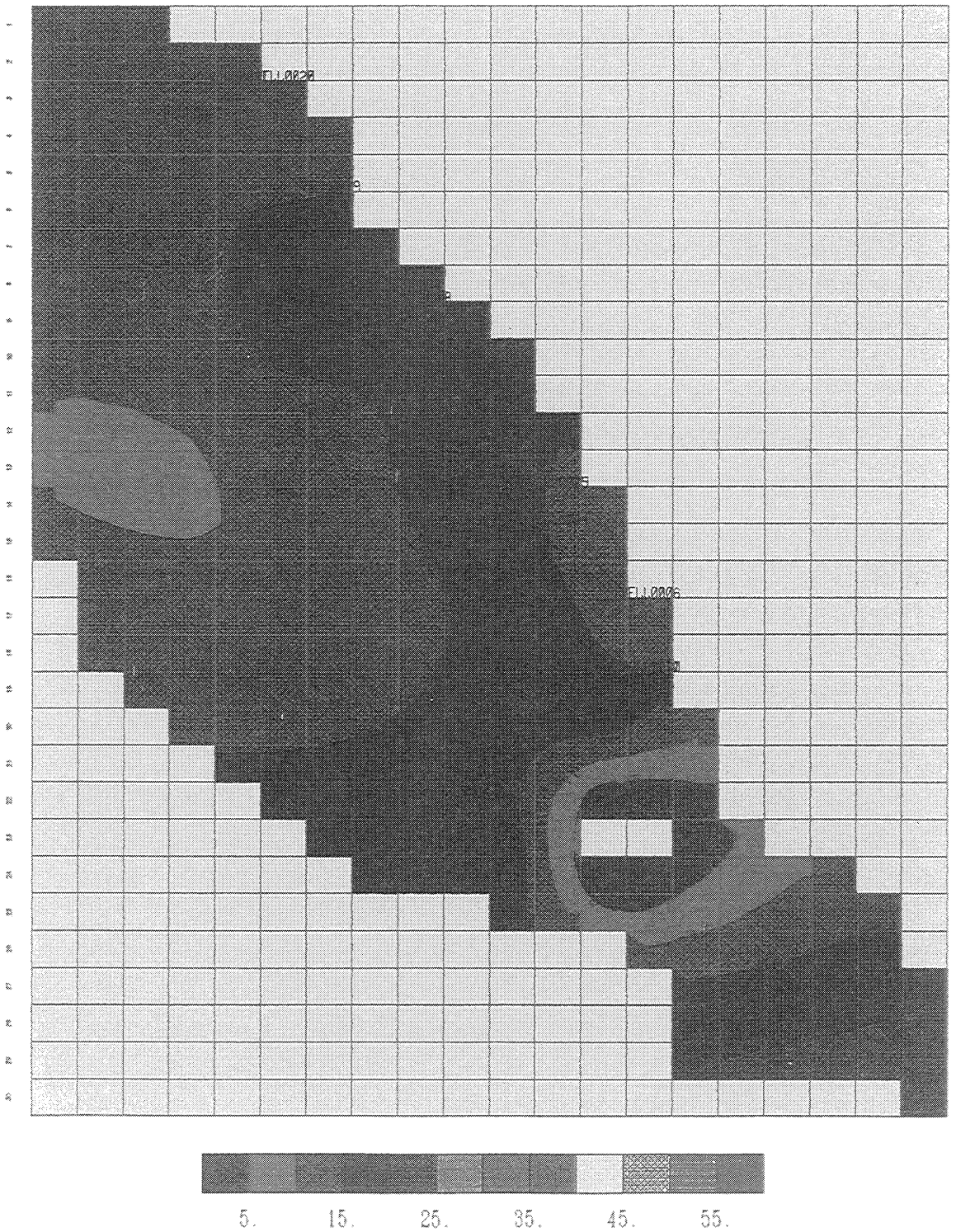


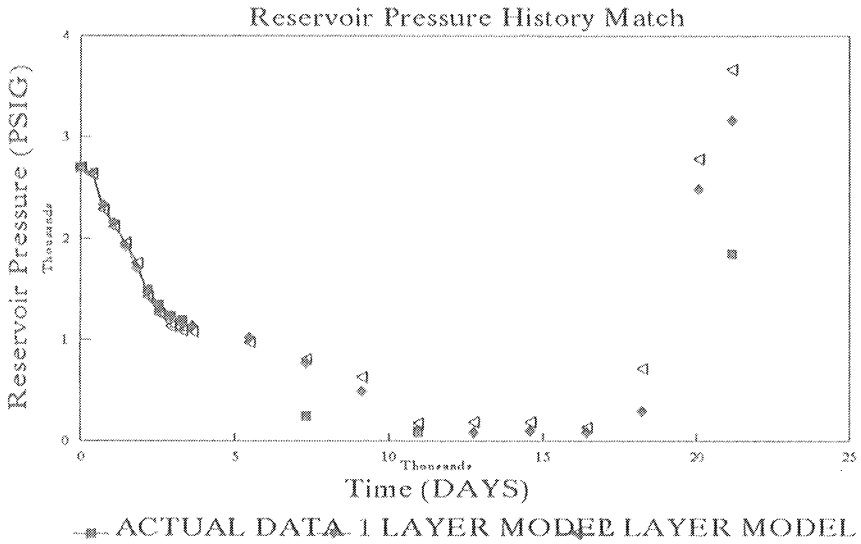
pn93:Layer 1/Gross Thickness

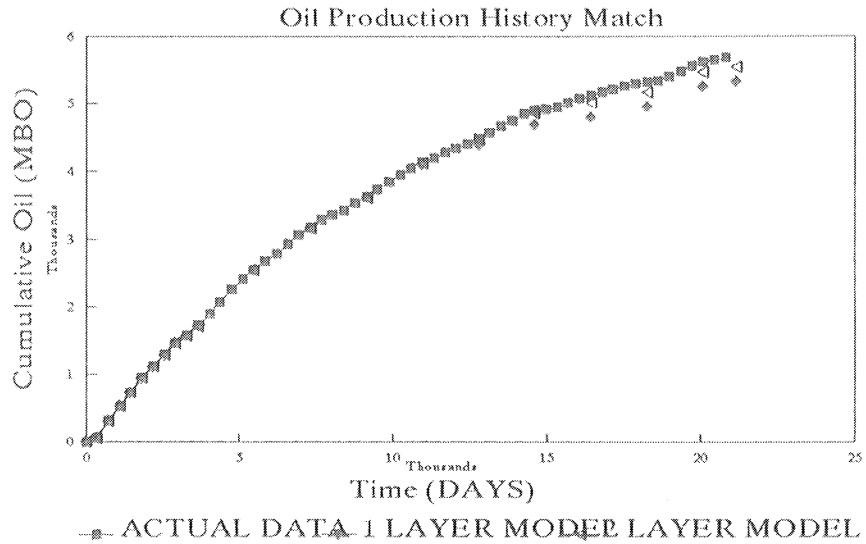


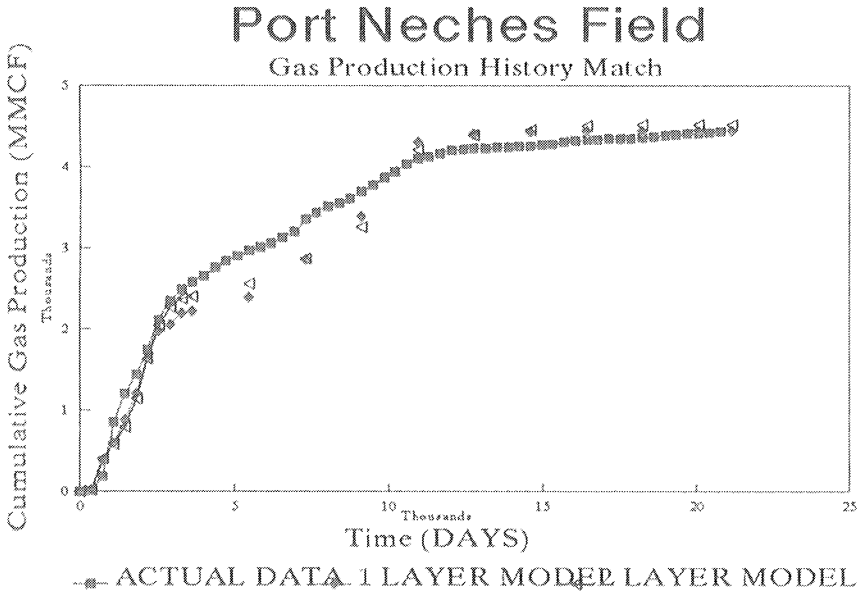
5. 15. 25. 35. 45. 55.

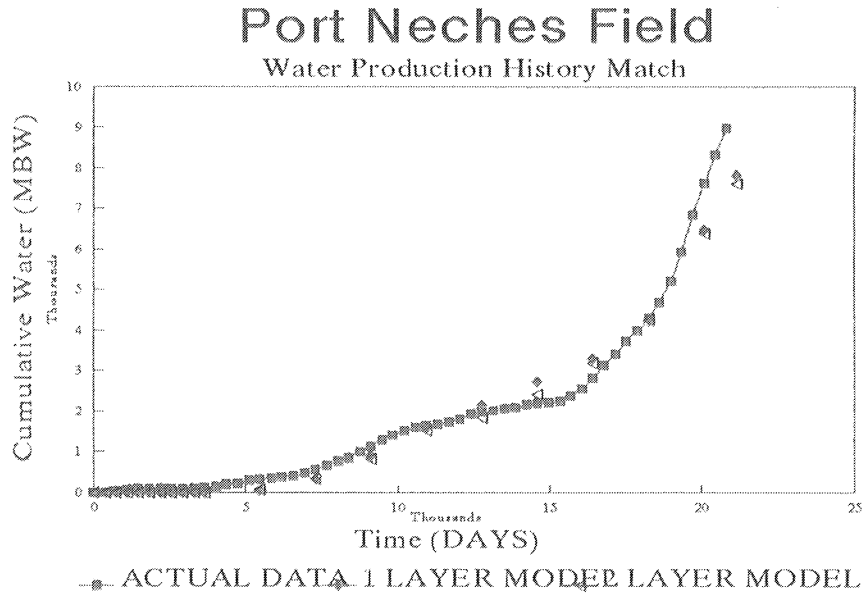
pn93:Layer 2/Gross Thickness

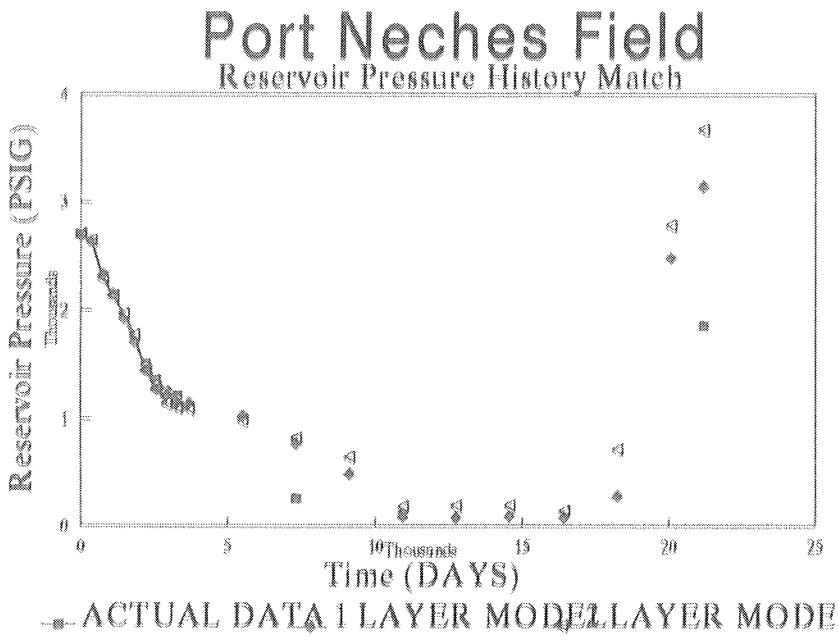


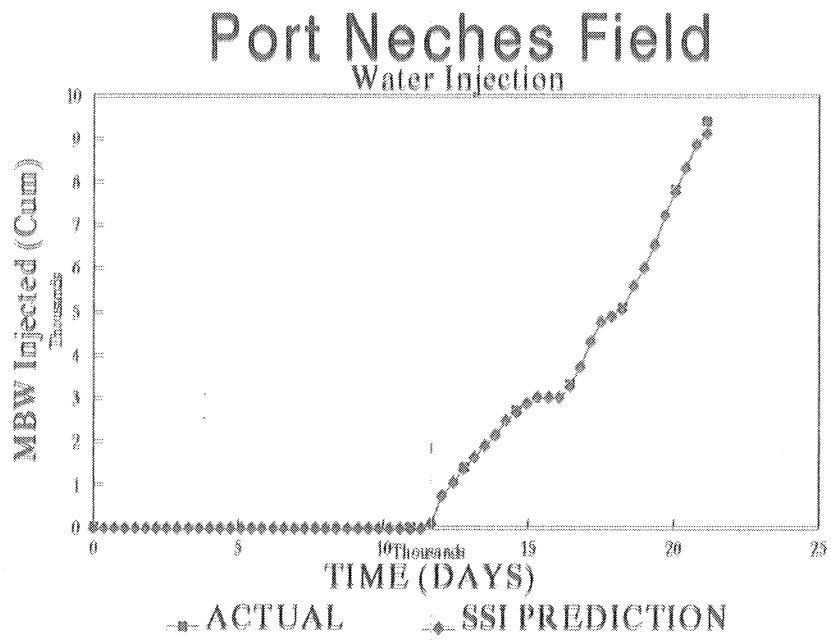

Reservoir Pressure History Match
Reservoir Pressure (PSIG)
Thousands
Time (DAYS)
Thousands
ACTUAL DATA
1 LAYER MODEL
2 LAYER MODEL

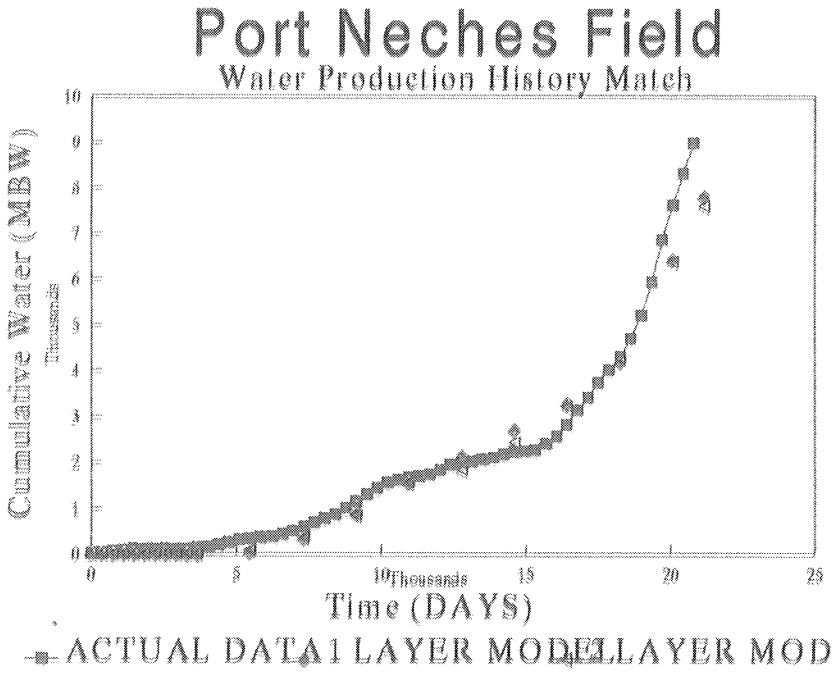

Oil Production History Match
Cumulative Oil (MBO)
Thousands
Time (DAYS)
Thousands
ACTUAL DATA
1 LAYER MODEL
2 LAYER MODEL

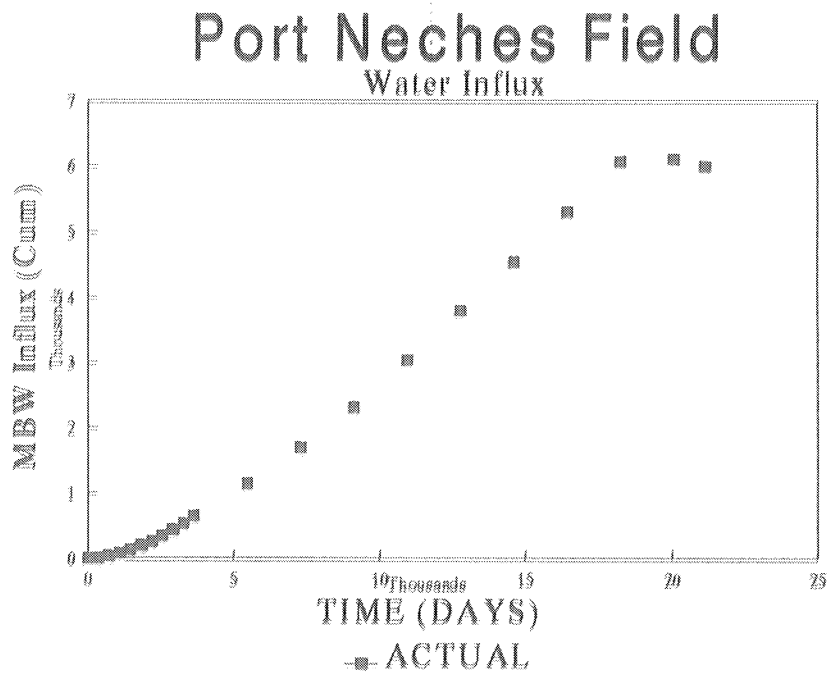

Port Neches Field
Gas Production History Match
Cumulative Gas Production (MMCF)
Thousands
Time (DAYS)
Thousands
ACTUAL DATA
1 LAYER MODEL
2 LAYER MODEL

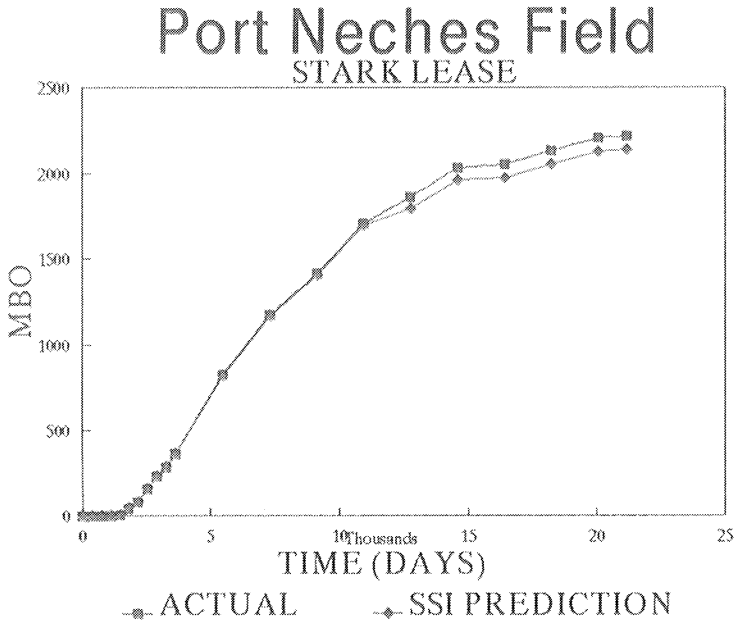

Port Neches Field
Water Production History Match
Cumulative Water (MBW)
Thousands
Time (DAYS)
Thousands
ACTUAL DATA
1 LAYER MODEL
2 LAYER MODEL

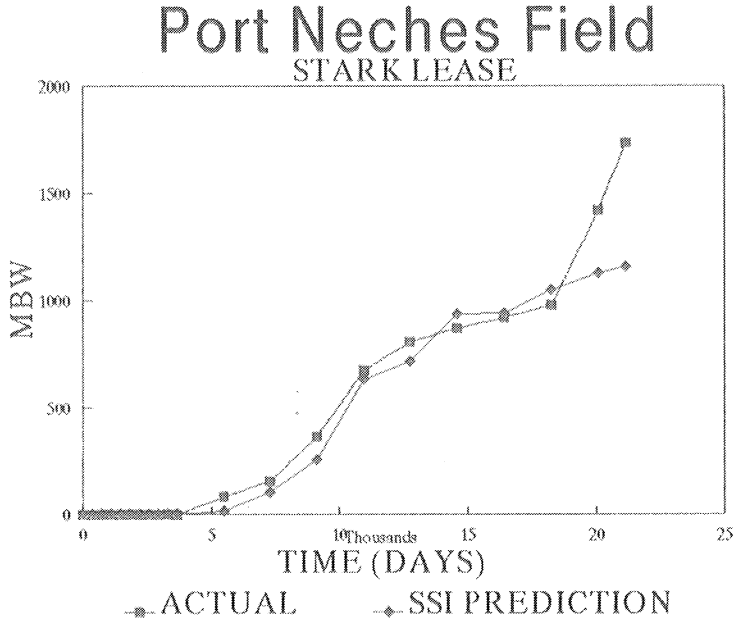

Port Neches Field
Reservoir Pressure History Match
Reservoir Pressure (PSIG)
Thousands
Time (DAYS)
ACTUAL DATA
1 LAYER MODEL
2 LAYER MODE

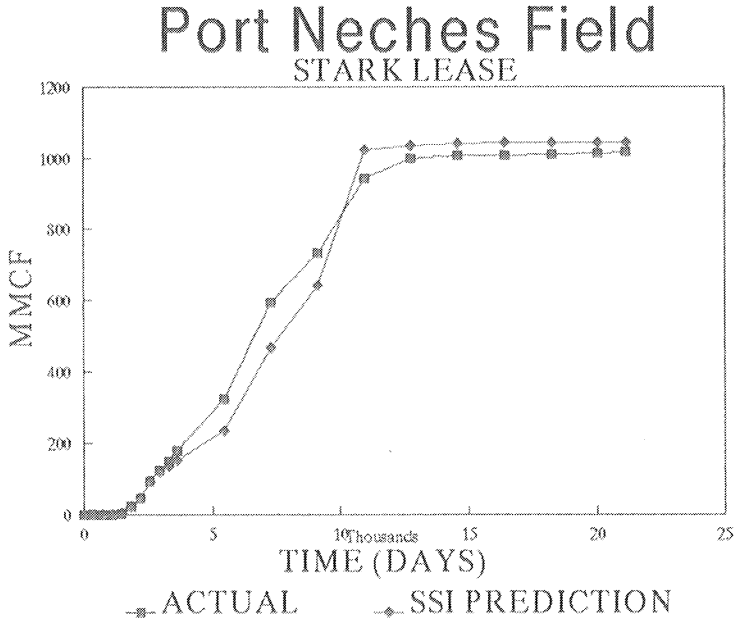

Port Neches Field
Water Injection
MBW Injected (Cum)
Thousands
TIME (DAYS)
ACTUAL
SSI PREDICTION

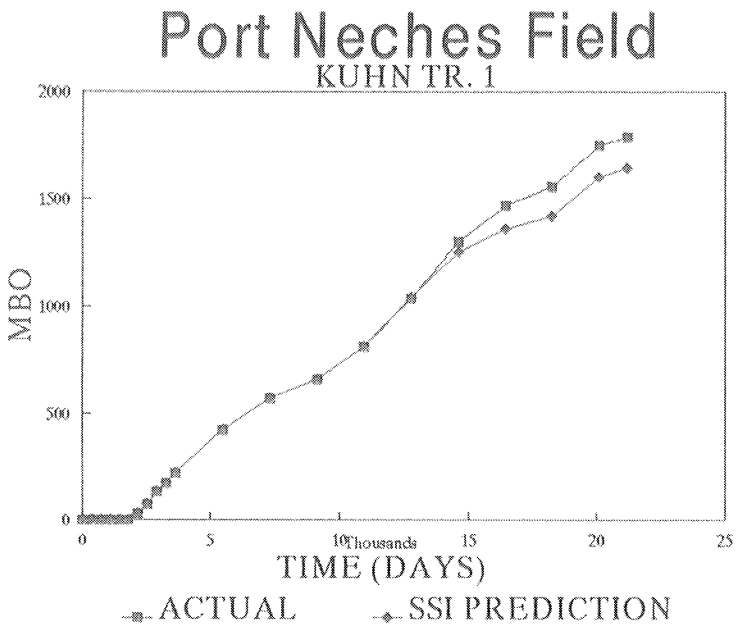

Port Neches Field
Water Production History Match
Cumulative Water (MBW)
Thousands
Time (DAYS)
ACTUAL DATA
1 LAYER MODEL
2 LAYER MOD

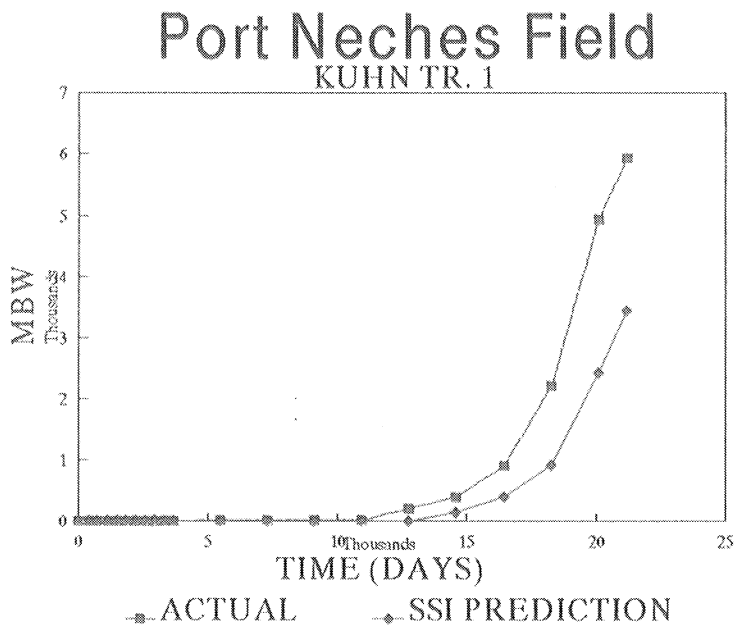

Port Neches Field
Water Influx
MBW Influx (Cum)
Thousands
TIME (DAYS)
ACTUAL

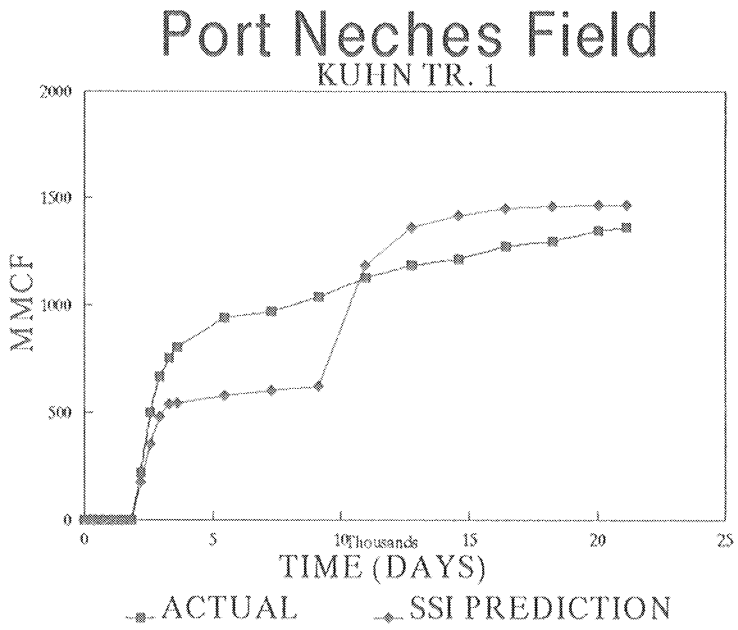

Port Neches Field
STARK LEASE
MBO
2500
2000
1500
1000
500
0
0
5
10Thousands
15
20
25
TIME (DAYS)
ACTUAL
SSI PREDICTION

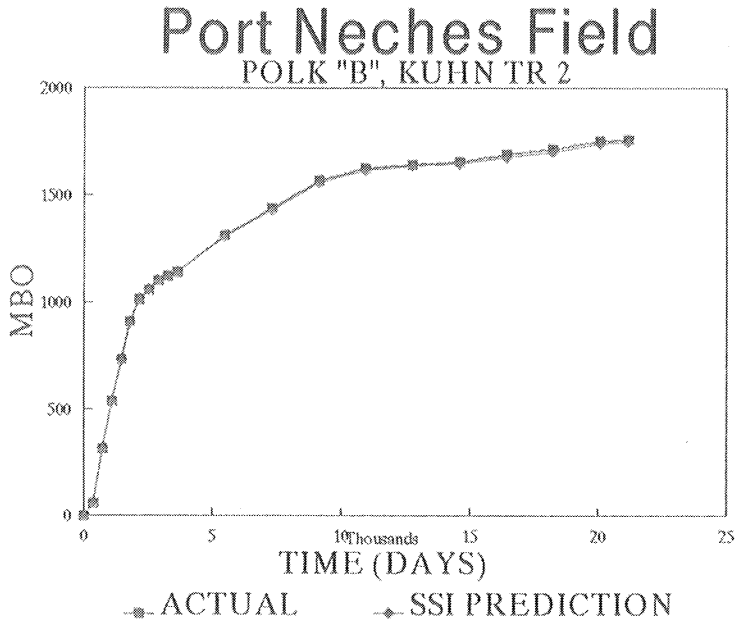

Port Neches Field
STARK LEASE
MBW
2000
1500
1000
500
0
0
5
10Thousands
15
20
25
TIME (DAYS)
ACTUAL
SSI PREDICTION

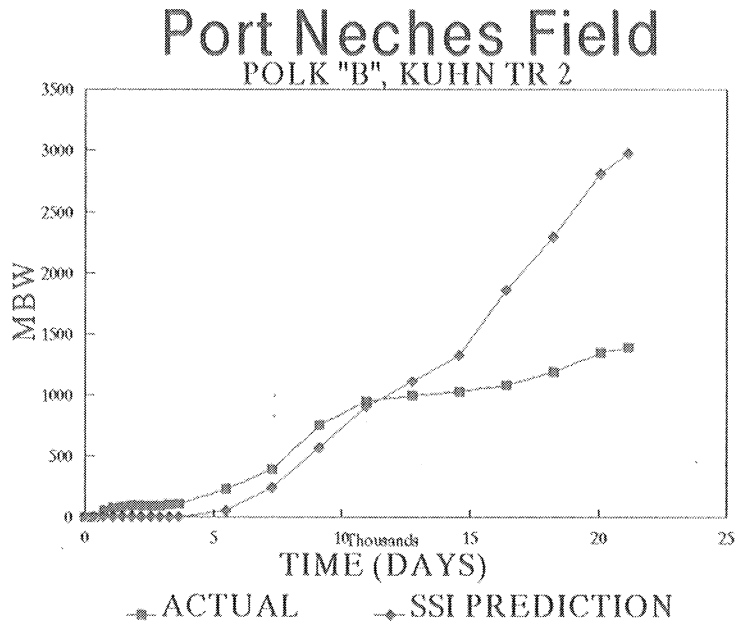

Port Neches Field
STARK LEASE
MMCF
1200
1000
800
600
400
200
0
0
5
10Thousands
15
20
25
TIME (DAYS)
ACTUAL
SSI PREDICTION

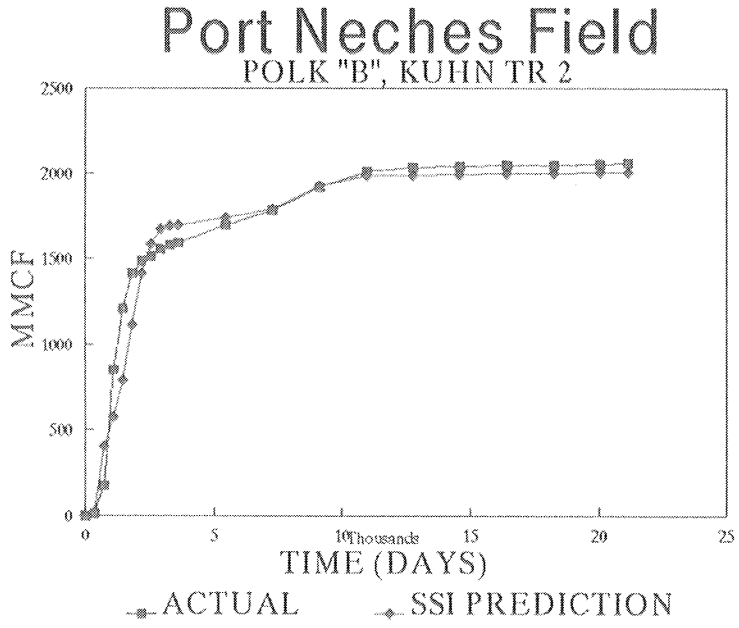

Port Neches Field
KUHN TR. 1
MBO
2000
1500
1000
500
0
0
5
10Thousands
15
20
25
TIME (DAYS)
ACTUAL
SSI PREDICTION

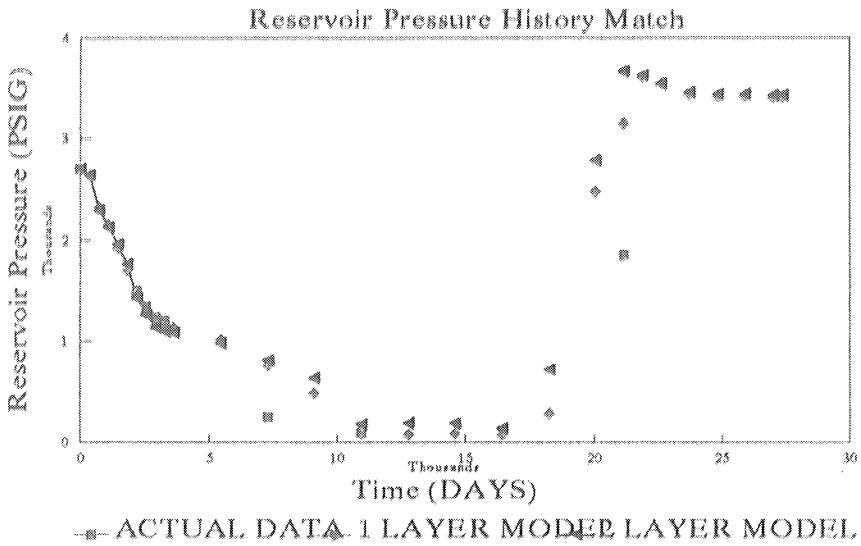

Port Neches Field
KUHN TR. 1
MBW
Thousands
7
6
5
4
3
2
1
0
0
5
10Thousands
15
20
25
TIME (DAYS)
ACTUAL
SSI PREDICTION

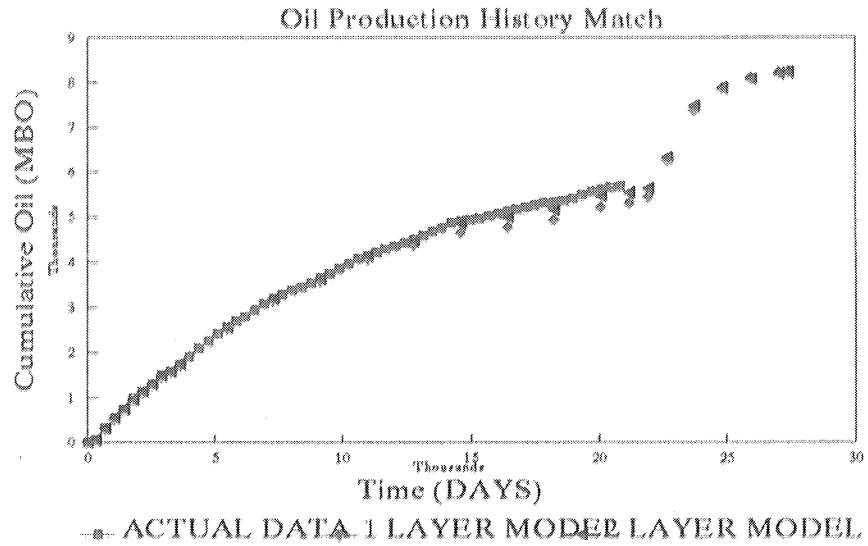

Port Neches Field
KUHN TR. 1
MMCF
2000
1500
1000
500
0
0
5
10Thousands
15
20
25
TIME (DAYS)
ACTUAL
SSI PREDICTION

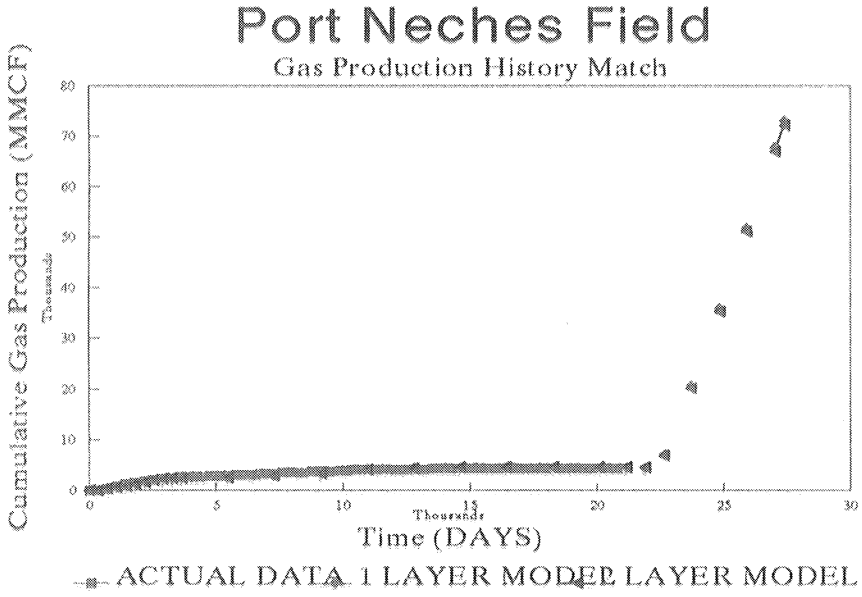

Port Neches Field
POLK "B", KUHN TR 2
MBO
2000
1500
1000
500
0
0
5
10Thousands
15
20
25
TIME (DAYS)
ACTUAL
SSI PREDICTION

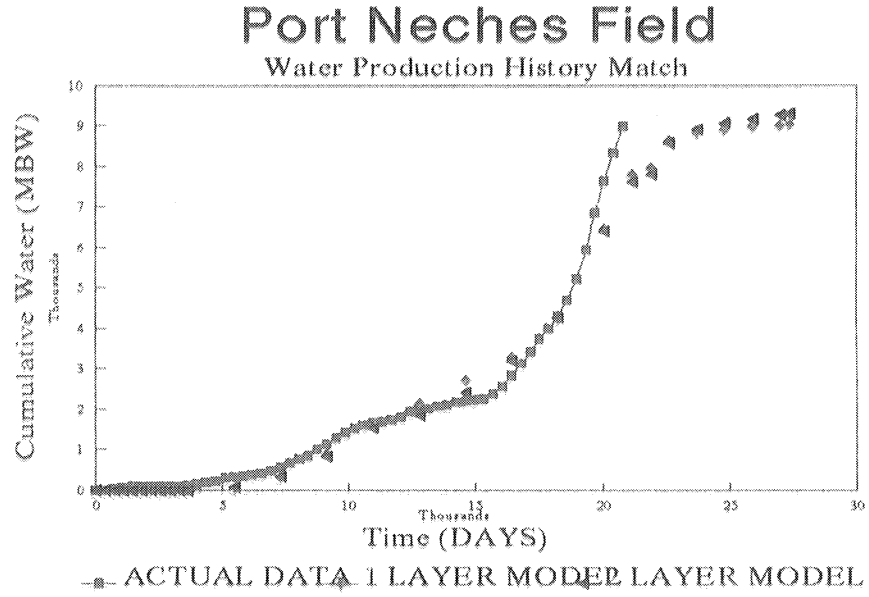

Port Neches Field
POLK "B", KUHN TR 2
MBW
3500
3000
2500
2000
1500
1000
500
0
0
5
10Thousands
15
20
25
TIME (DAYS)
ACTUAL
SSI PREDICTION

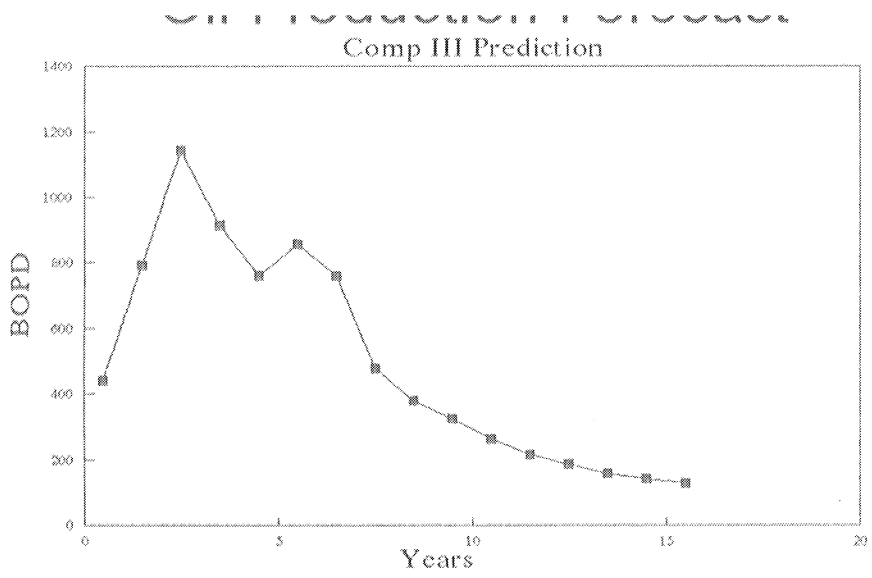

Port Neches Field
POLK "B", KUHN TR 2
MMCF
2500
2000
1500
1000
500
0
0
5
10Thousands
15
20
25
TIME (DAYS)
ACTUAL
SSI PREDICTION

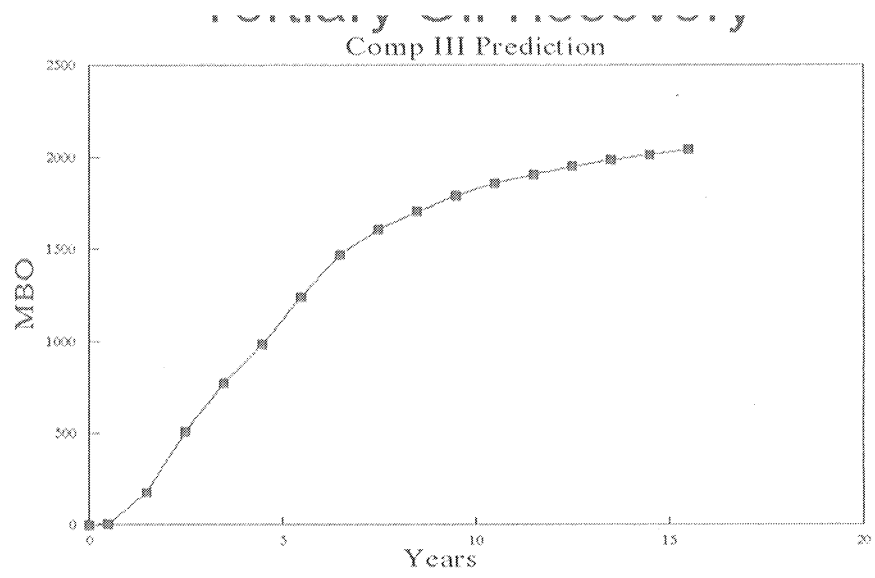

Reservoir Pressure History Match
Reservoir Pressure (PSIG)
Thousands
Time (DAYS)
Thousands
ACTUAL DATA
1 LAYER MODEL
2 LAYER MODEL

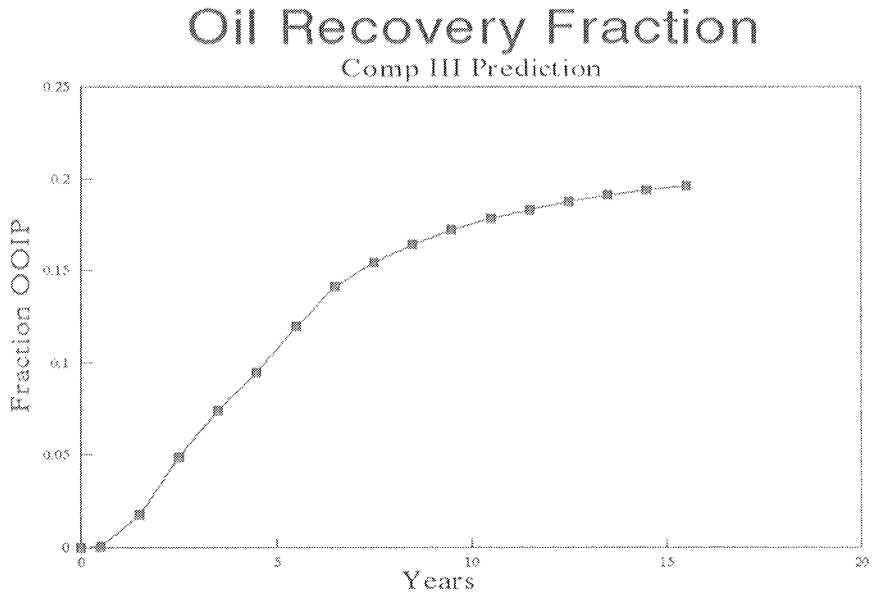

Oil Production History Match
Cumulative Oil (MBO)
Thousands
Time (DAYS)
Thousands
ACTUAL DATA
1 LAYER MODEL
2 LAYER MODEL

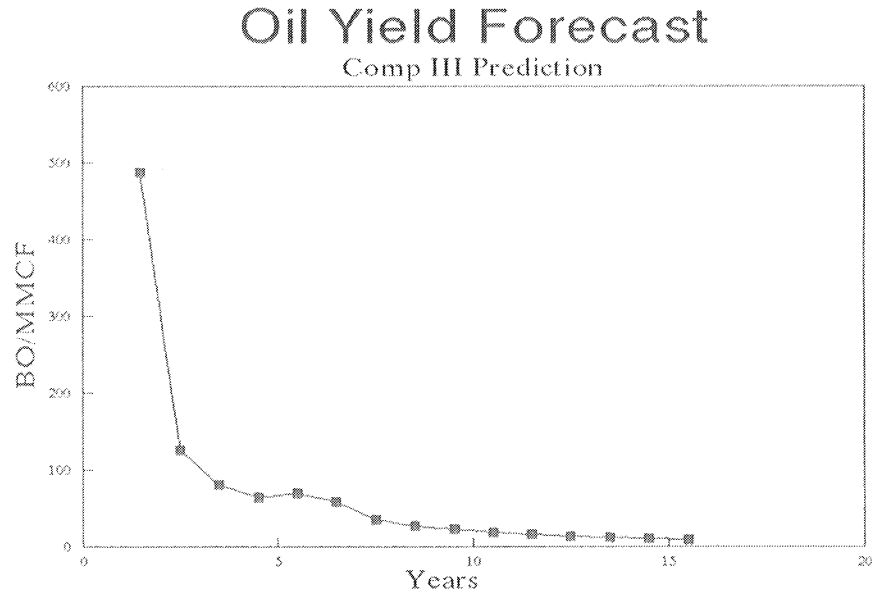

Port Neches Field
Gas Production History Match
Cumulative Gas Production (MMCF)
Thousands
Time (DAYS)
Thousands
ACTUAL DATA
1 LAYER MODEL
2 LAYER MODEL


Port Neches Field
Water Production History Match
Cumulative Water (MBW)
Thousands
Time (DAYS)
Thousands
ACTUAL DATA
1 LAYER MODEL
2 LAYER MODEL


Comp III Prediction
BOPD
Years
0
200
400
600
800
1000
1200
1400
0
5
10
15
20

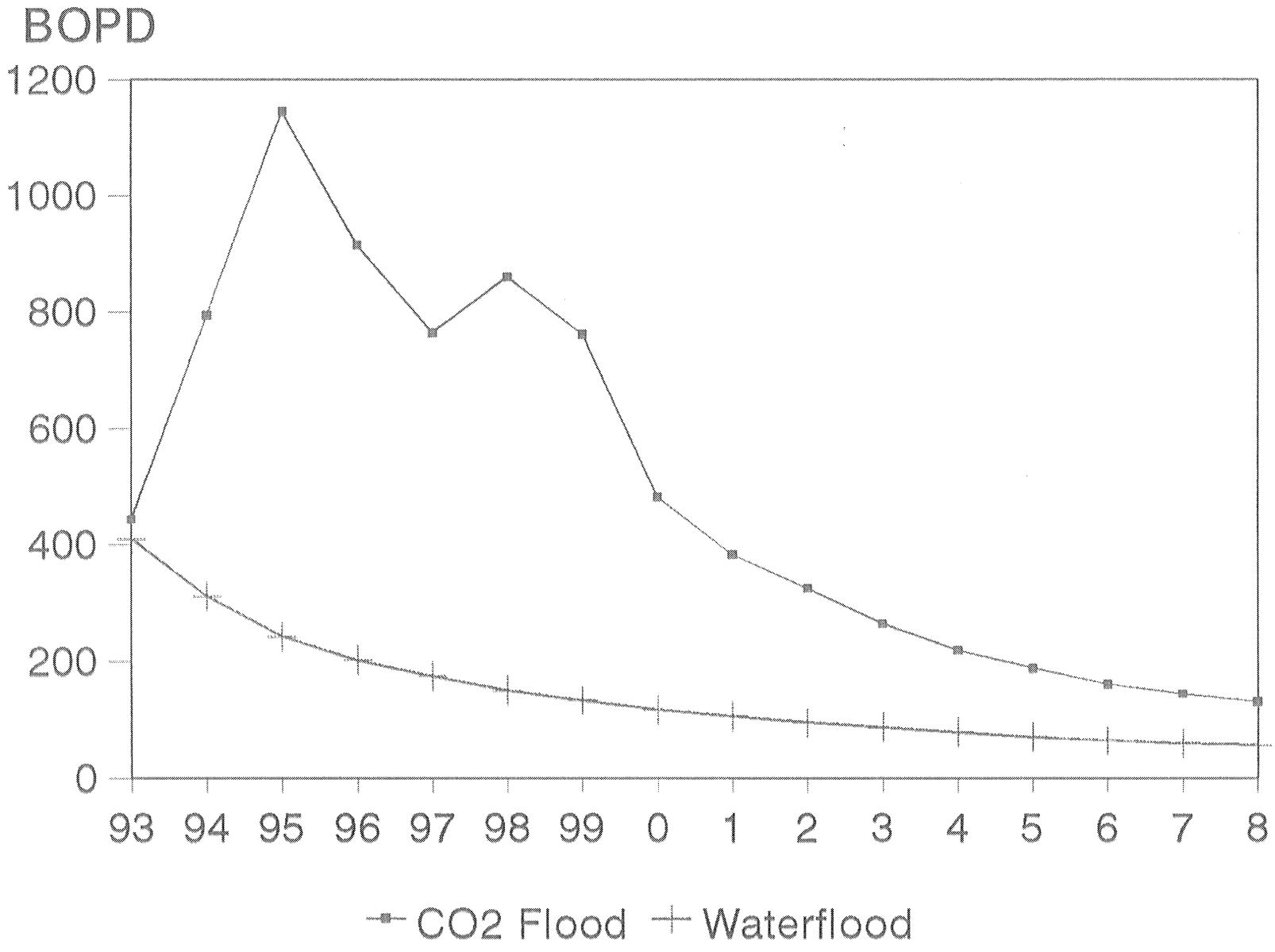

Comp III Prediction
MBO
Years
0
500
1000
1500
2000
2500
0
5
10
15
20


Oil Recovery Fraction
Comp III Prediction
Fraction OOIP
Years
0
0.05
0.1
0.15
0.2
0.25
0
5
10
15
20


Oil Yield Forecast
Comp III Prediction
BO/MMCF
Years
0
100
200
300
400
500
600
0
5
10
15
20

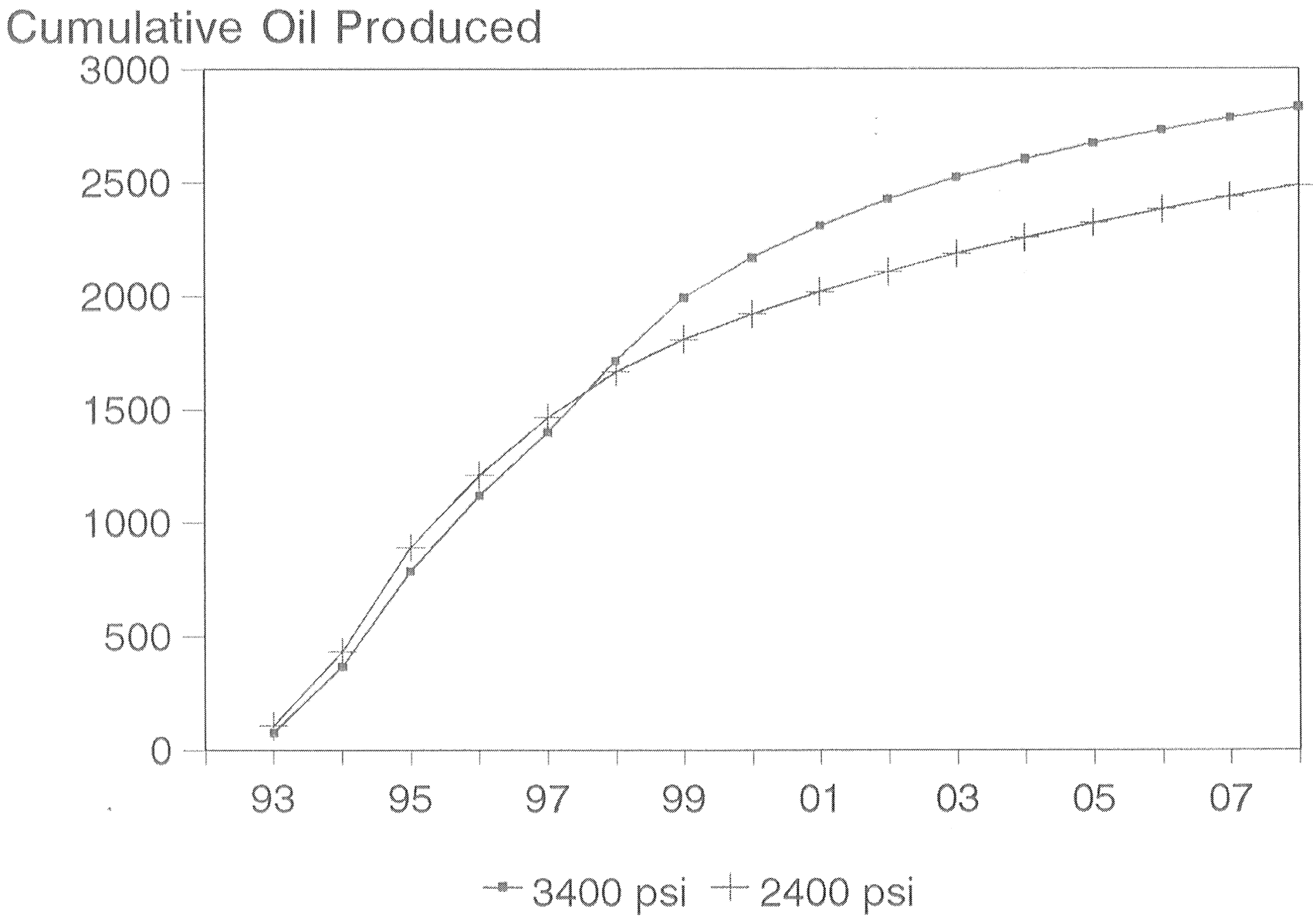
Oil Rate Comparison

Waterflood vs CO2

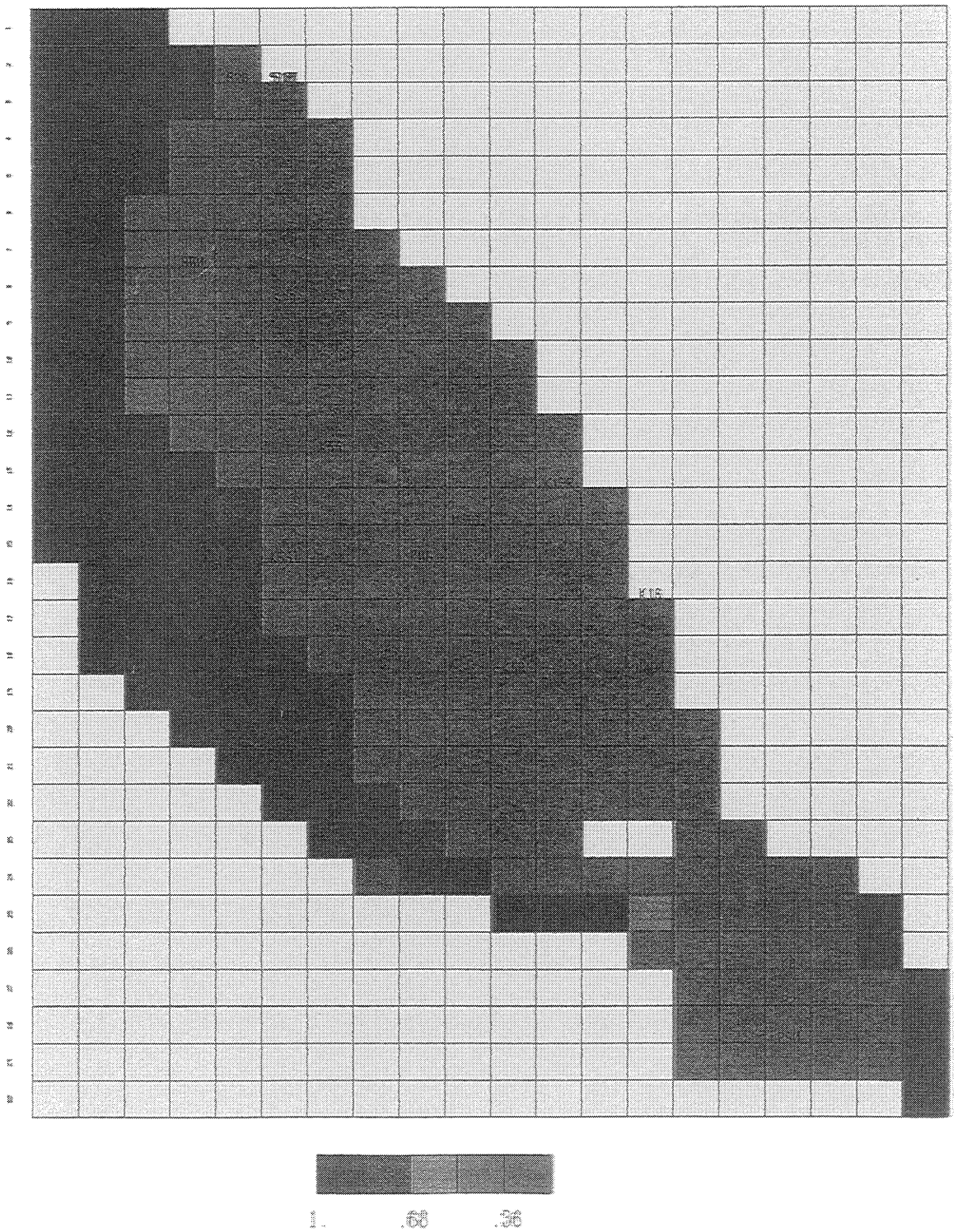


Reservoir Pressure Effects

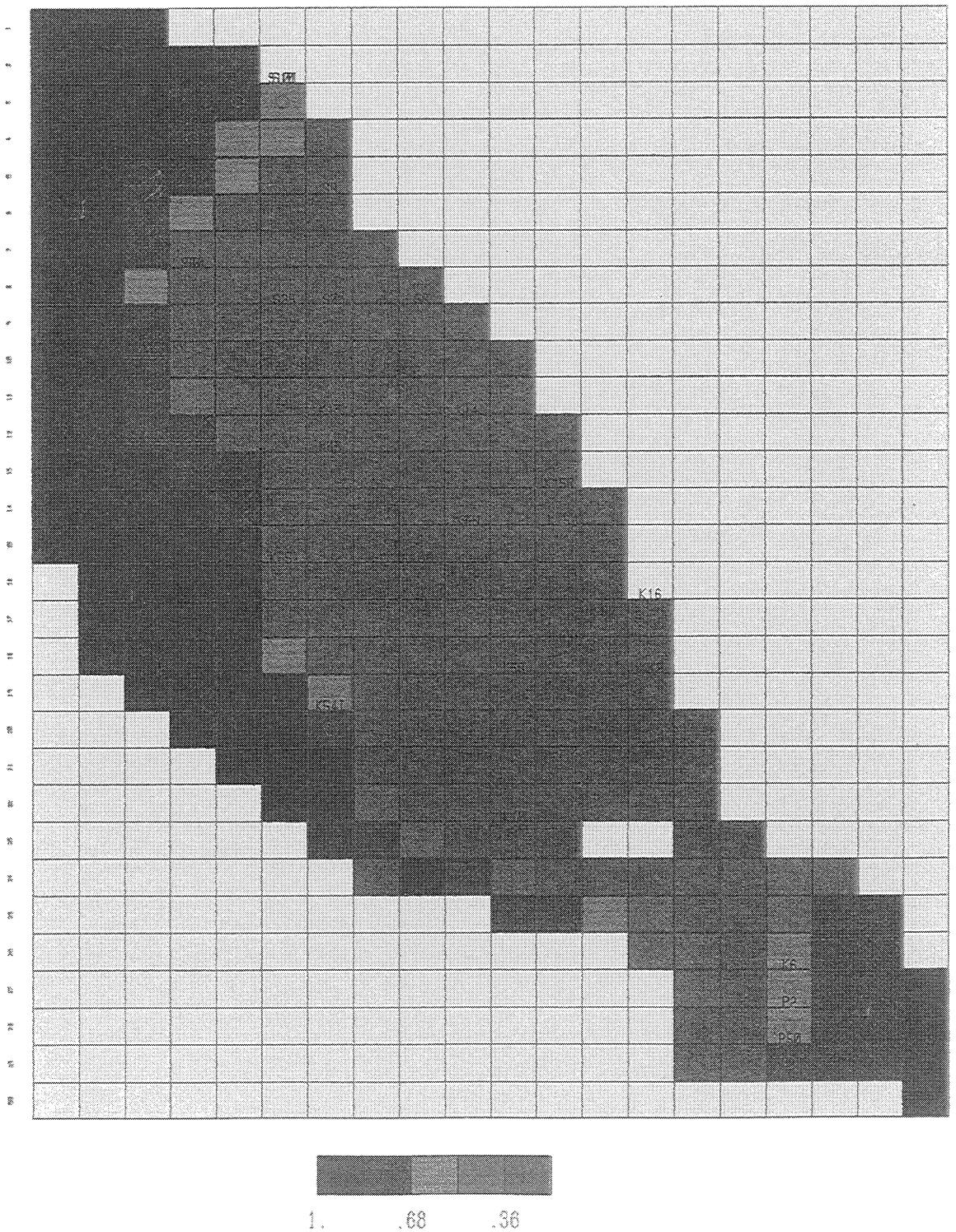
MMP = 3315 psia



pm93rst:Layer 1/Water Saturation/JAN 1, 1985

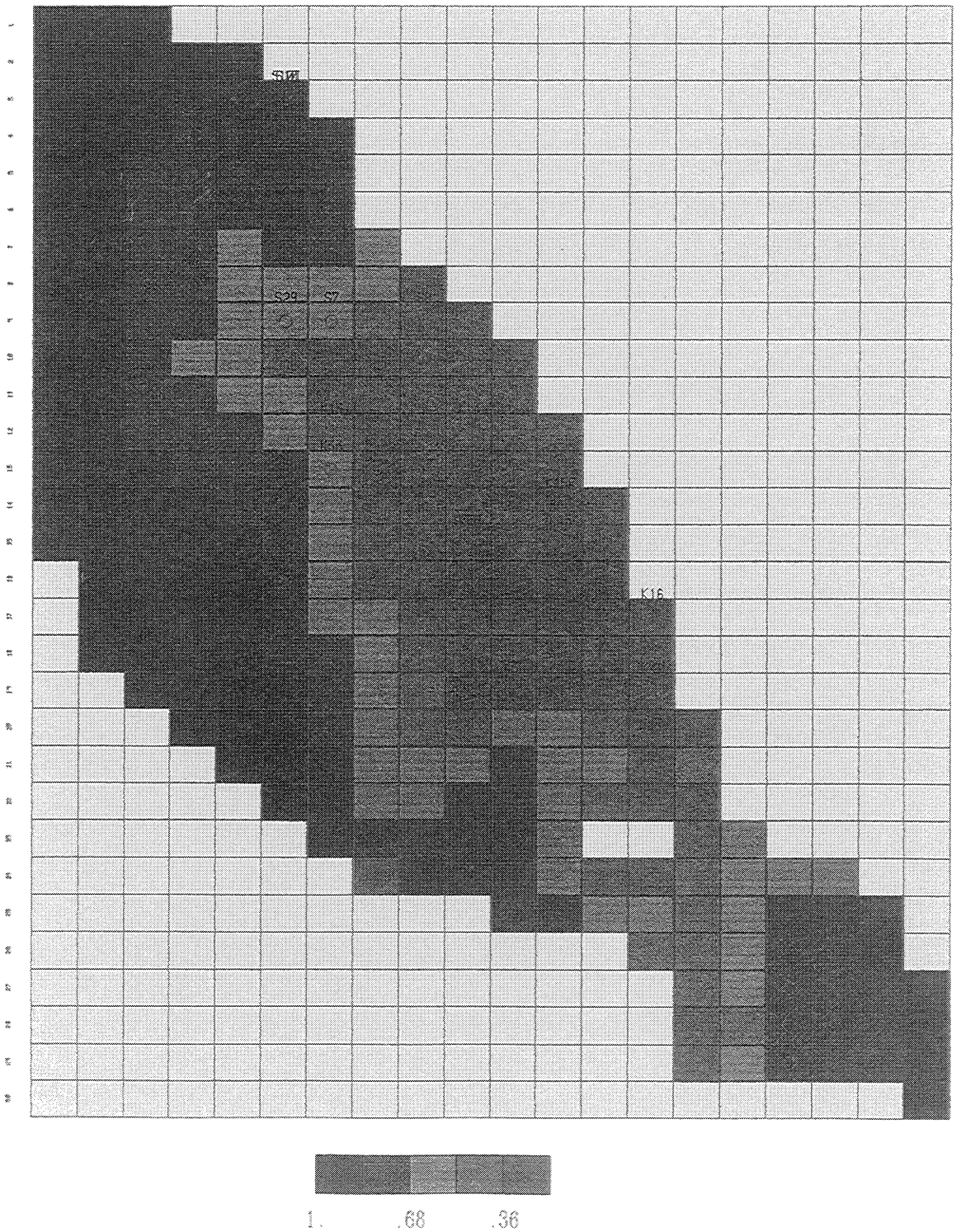


pn93rst:Layer 1/Water Saturation/DEC 25, 1963

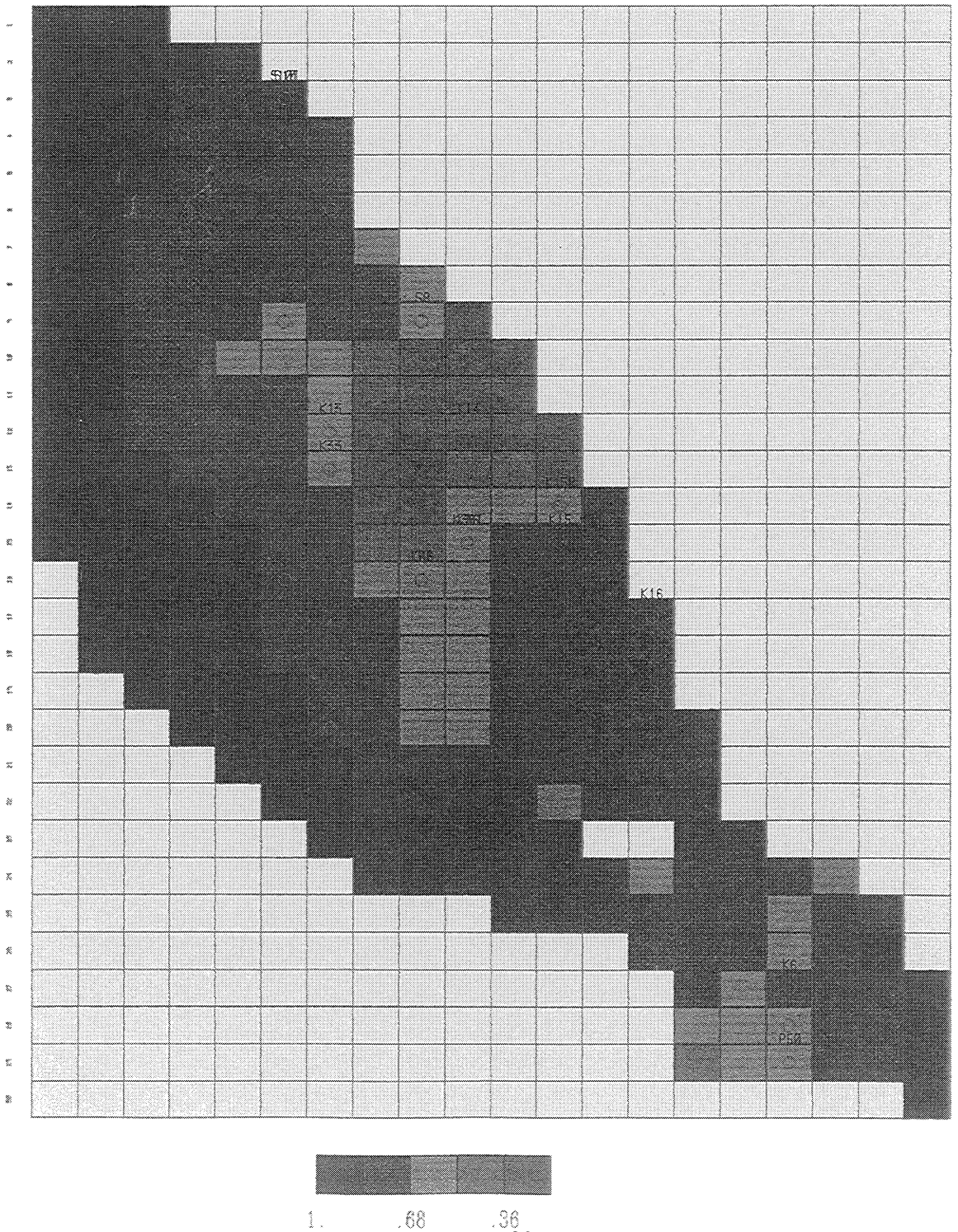


1. .68 .36

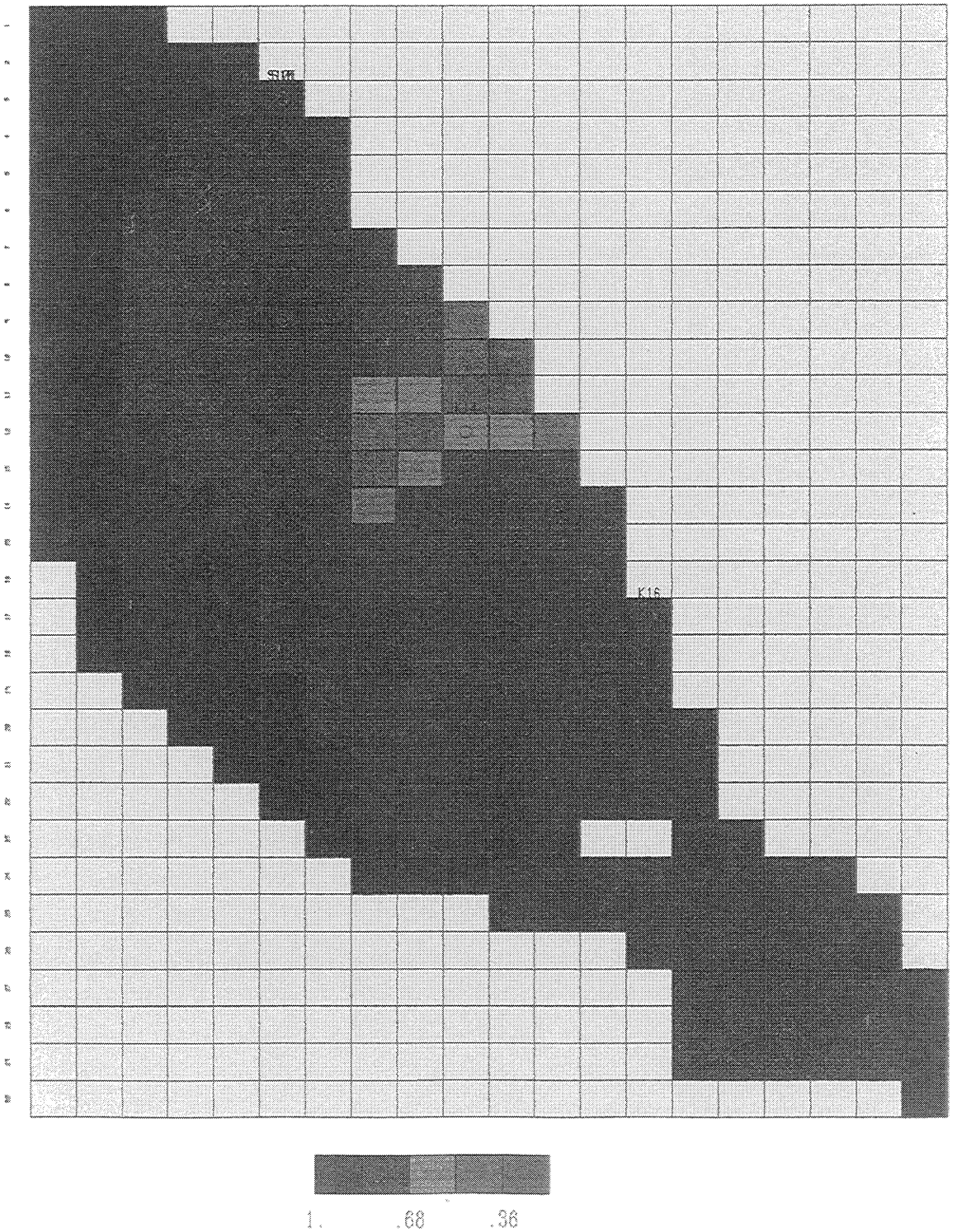
pm93rst:Layer 1/Water Saturation/DEC 22, 1973



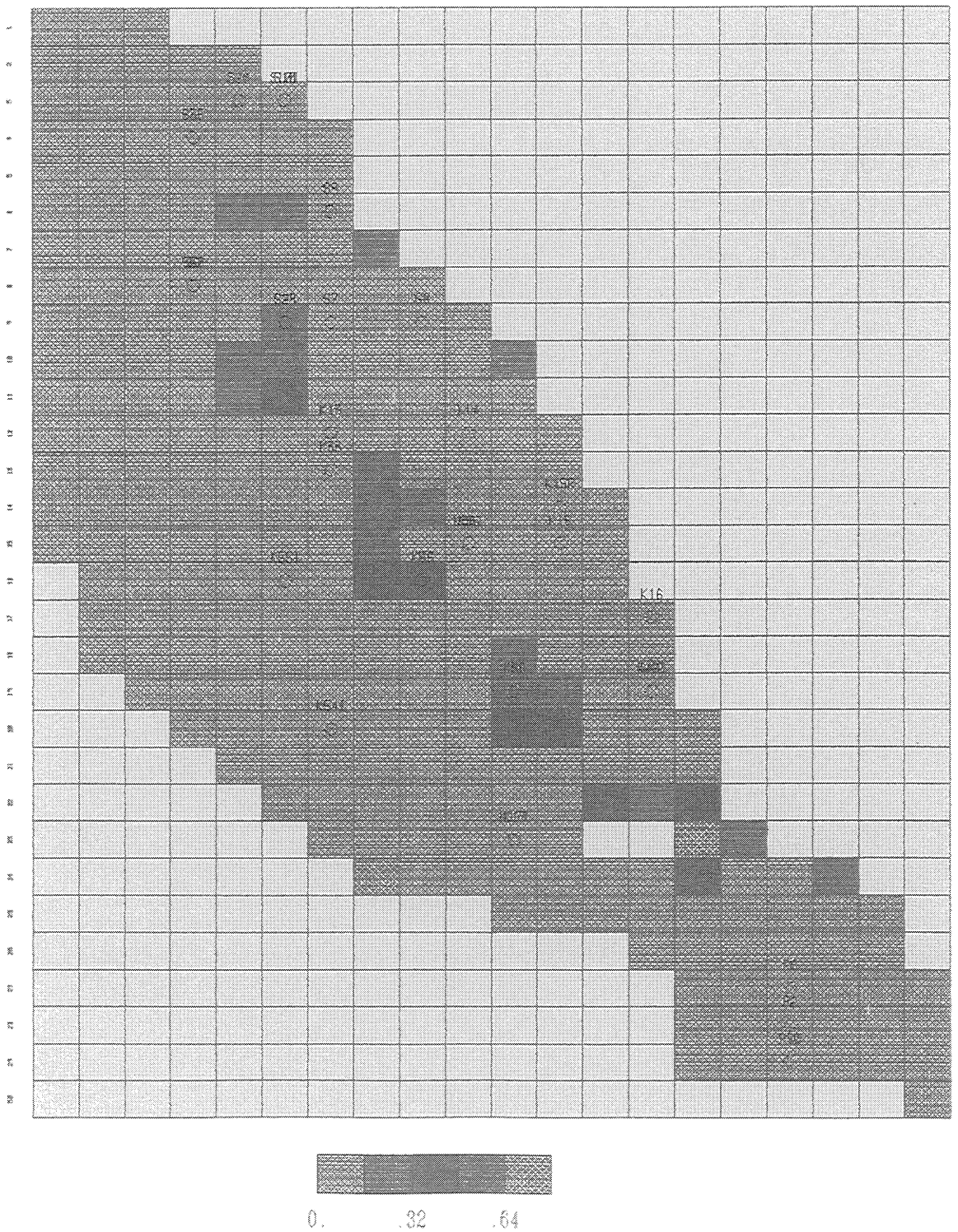
pn93rst:Layer 1/Water Saturation/DEC 18, 1991



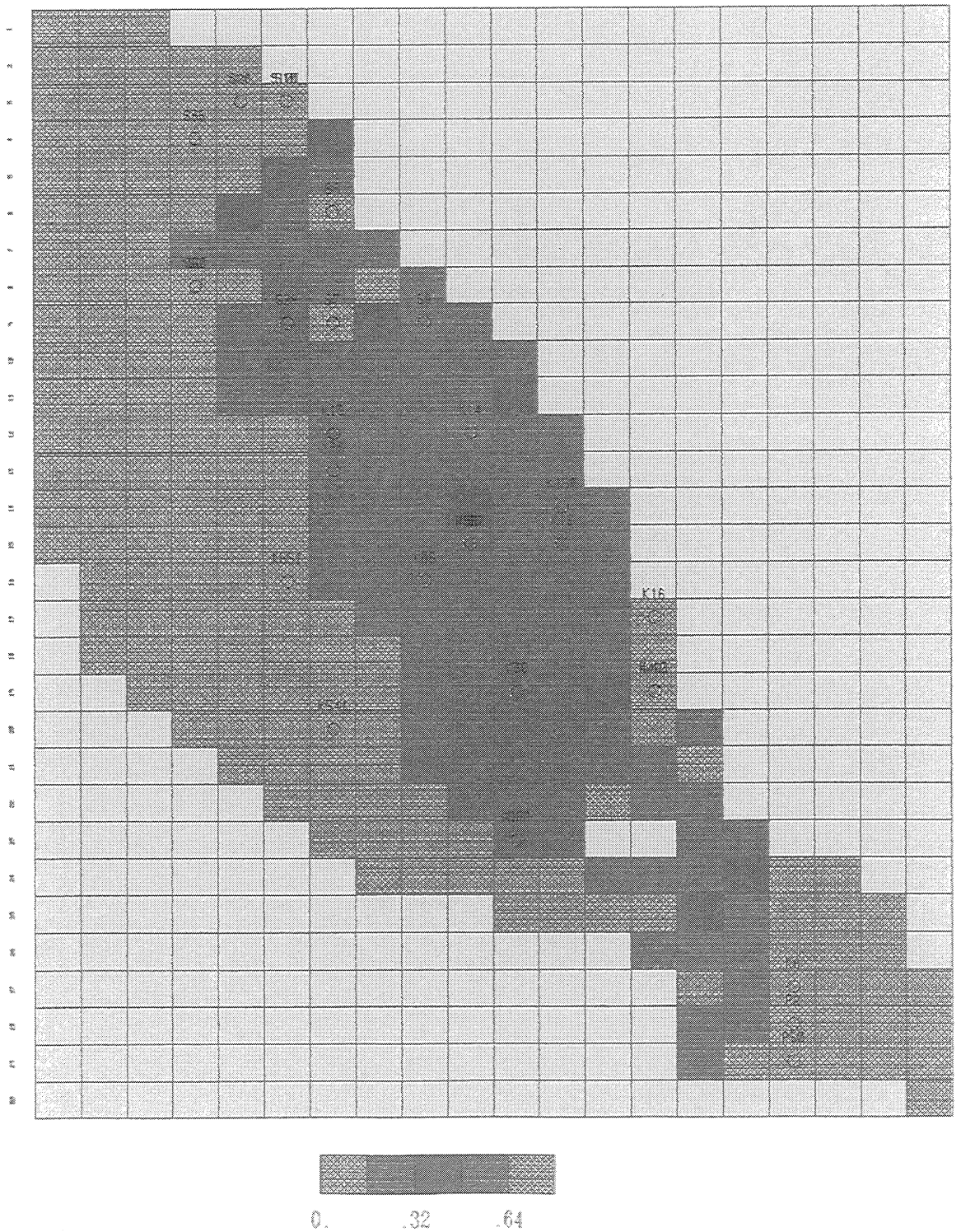
pm93rst:Layer 2/Water Saturation/DEC 18, 1991



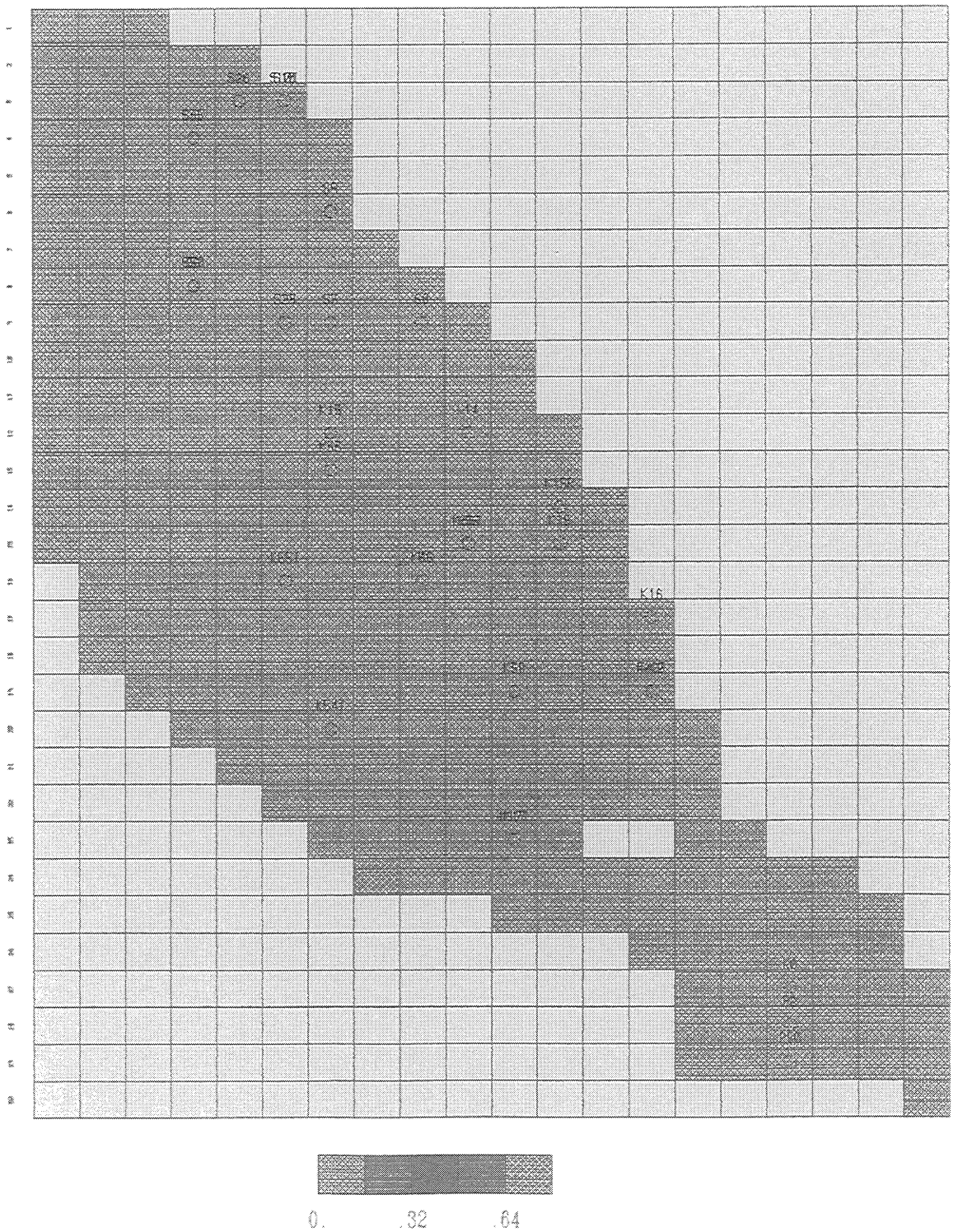
pn92rst:Layer 1/Gas Saturation/DEC 31, 1936



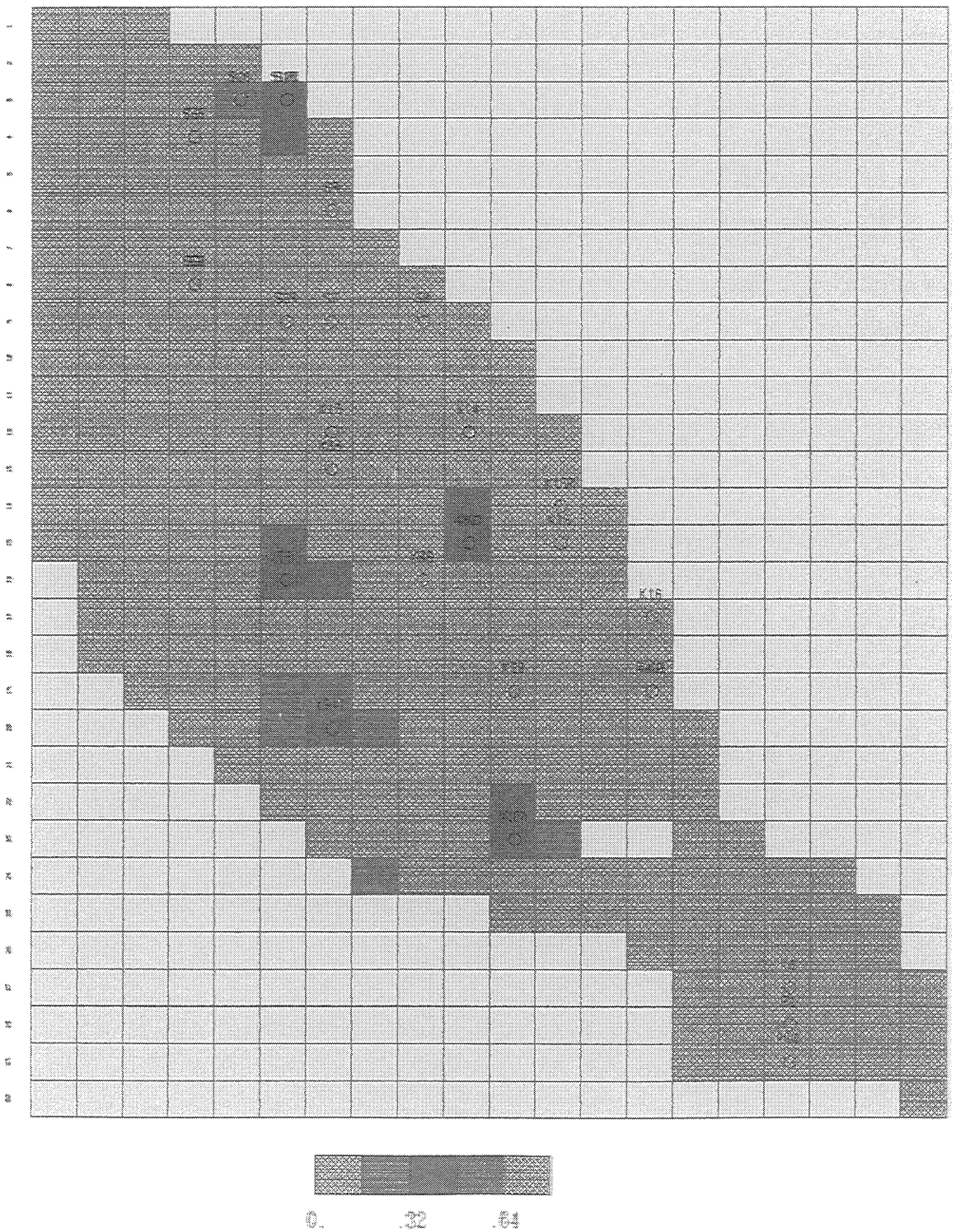
pn93rst:Layer 1/Gas Saturation/DEC 25, 1963



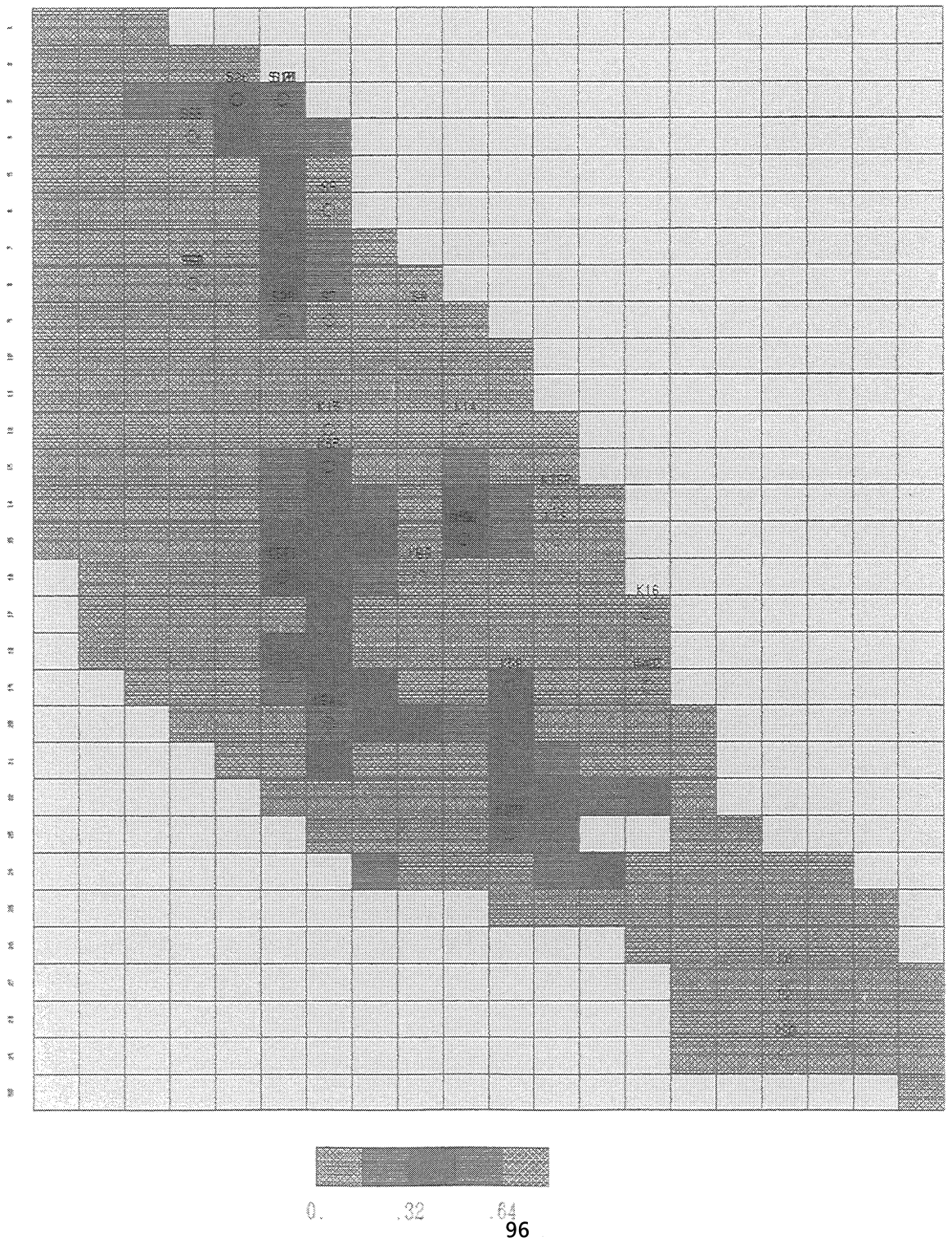
pn93rst:Layer 1/Gas Saturation/DEC 20, 1983



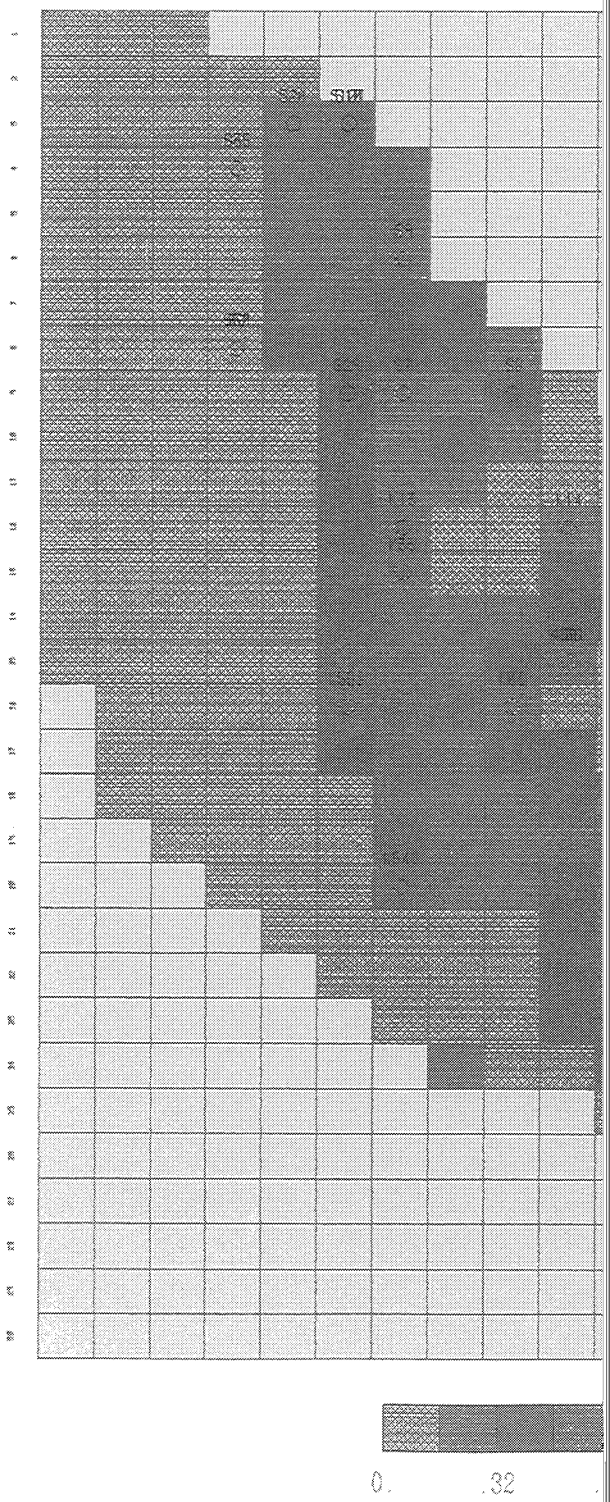
pn93rst:Layer 1/Gas Saturation/T.S.= 796



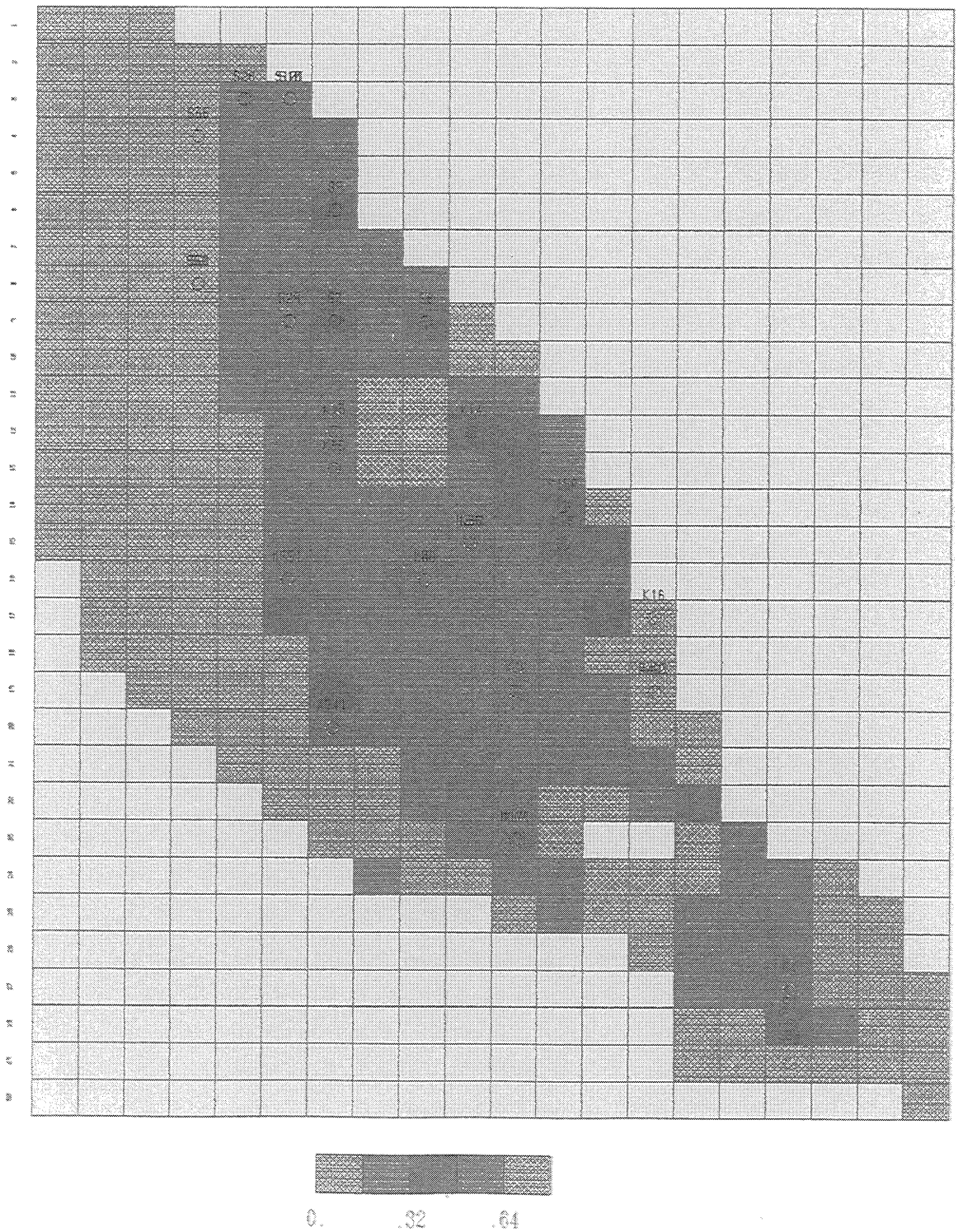
pn93rst:Layer 1/Gas Saturation/T.S.= 832



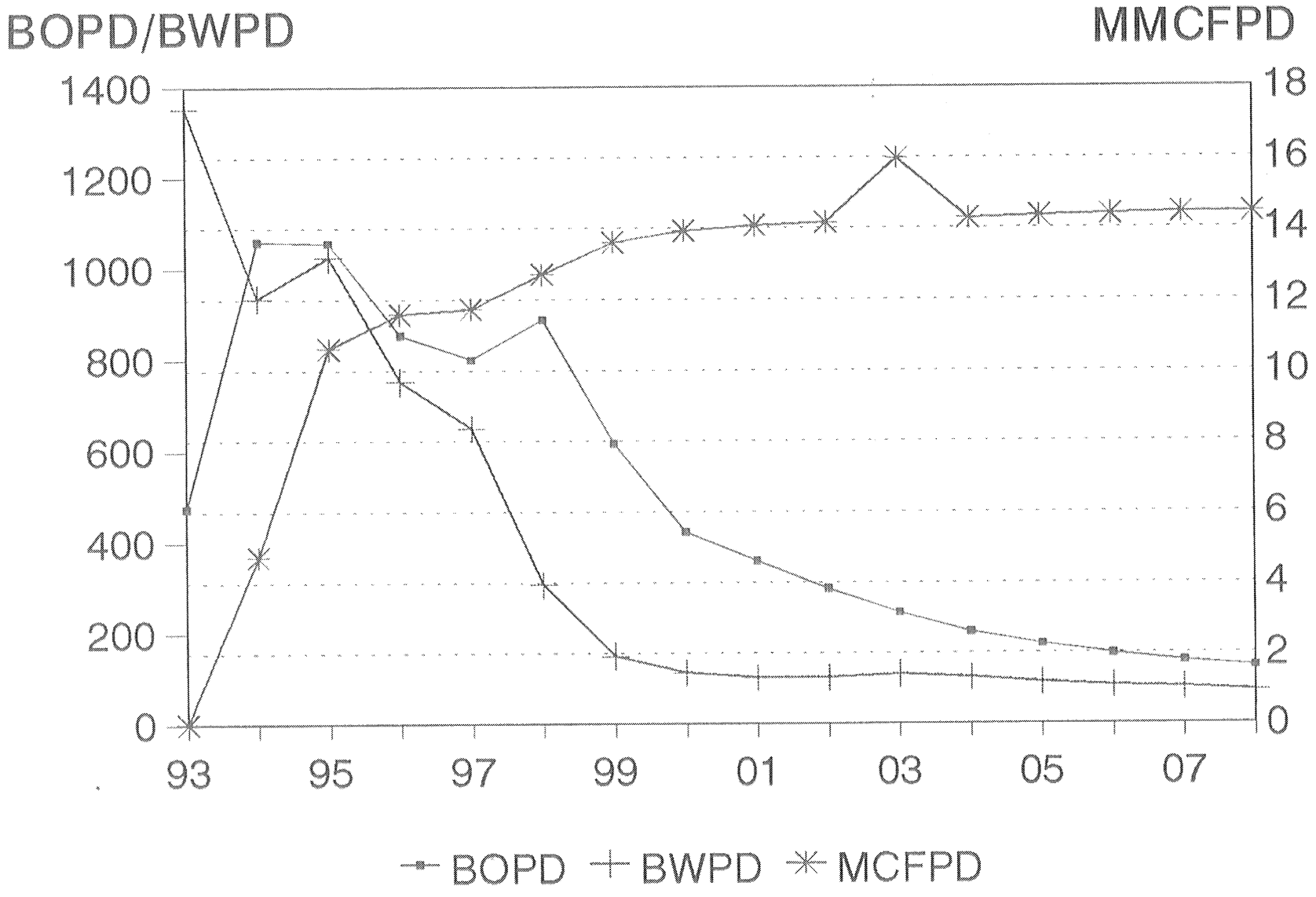
pn93rst:Layer 1/Gas



pnG3rst:Layer 1/Gas Saturation/T.S.=1041

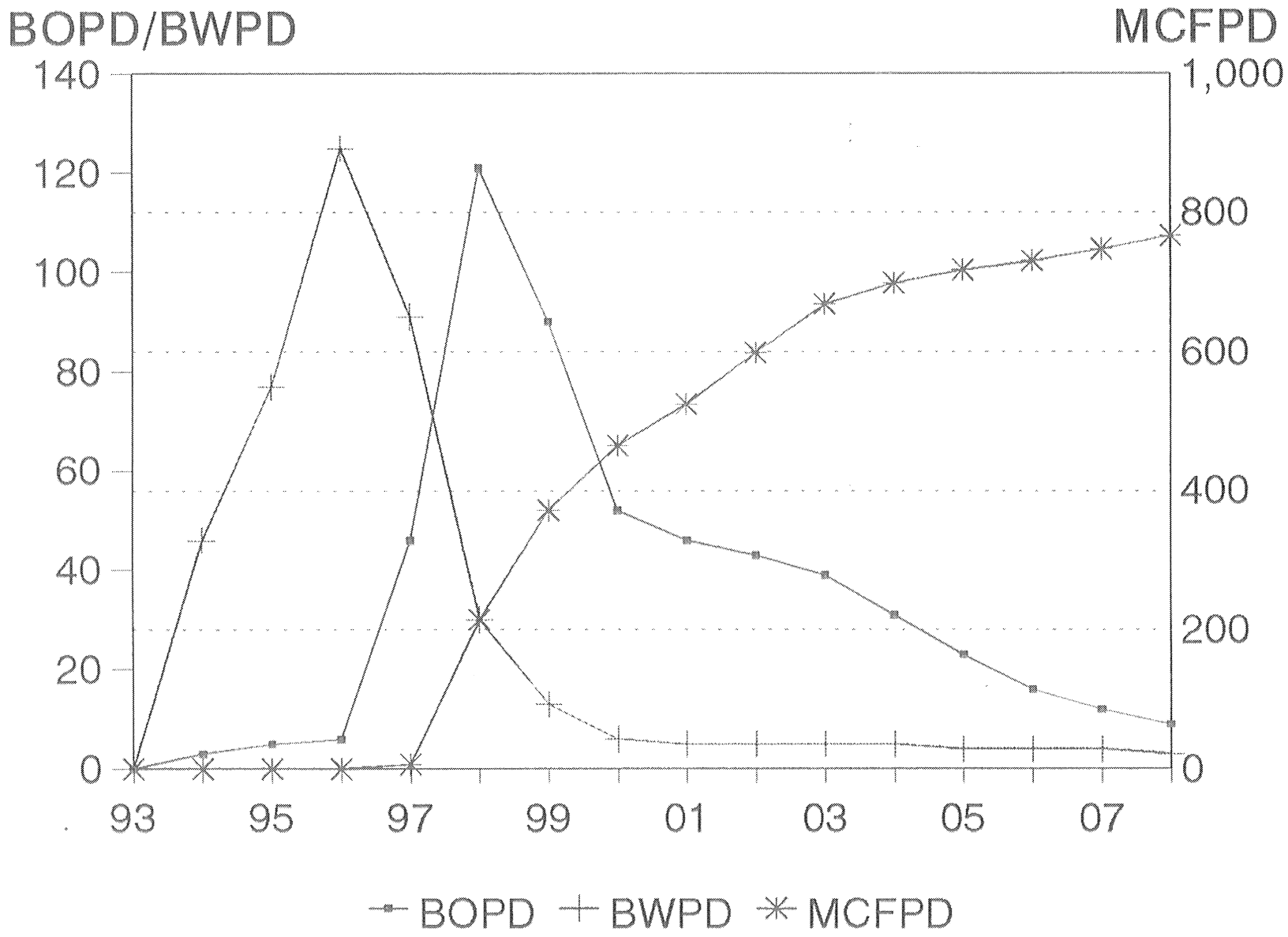


Total Project
CO2 Response



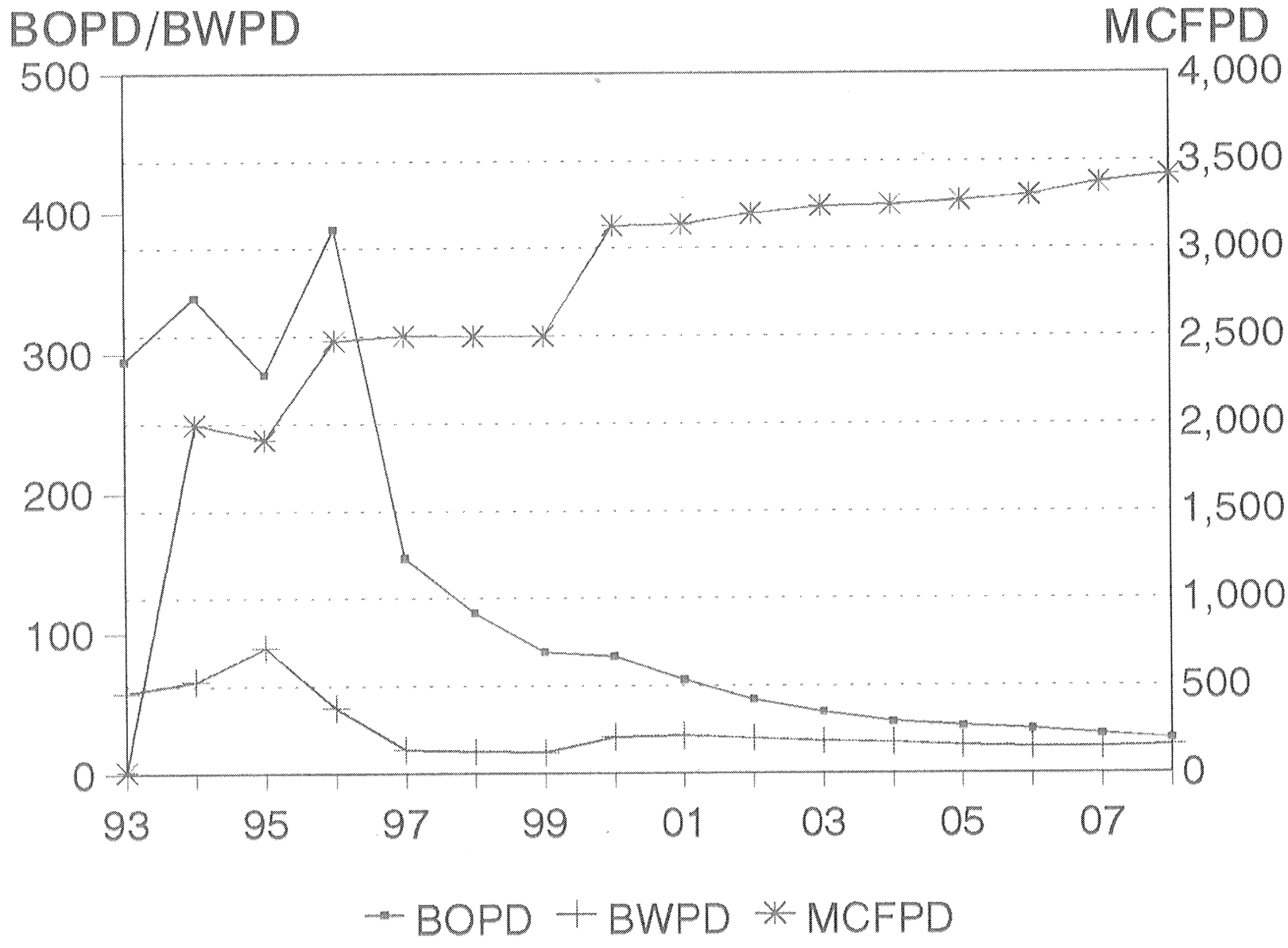
H. J. Kuhn Tr. 2 No. 6

CO2 Response



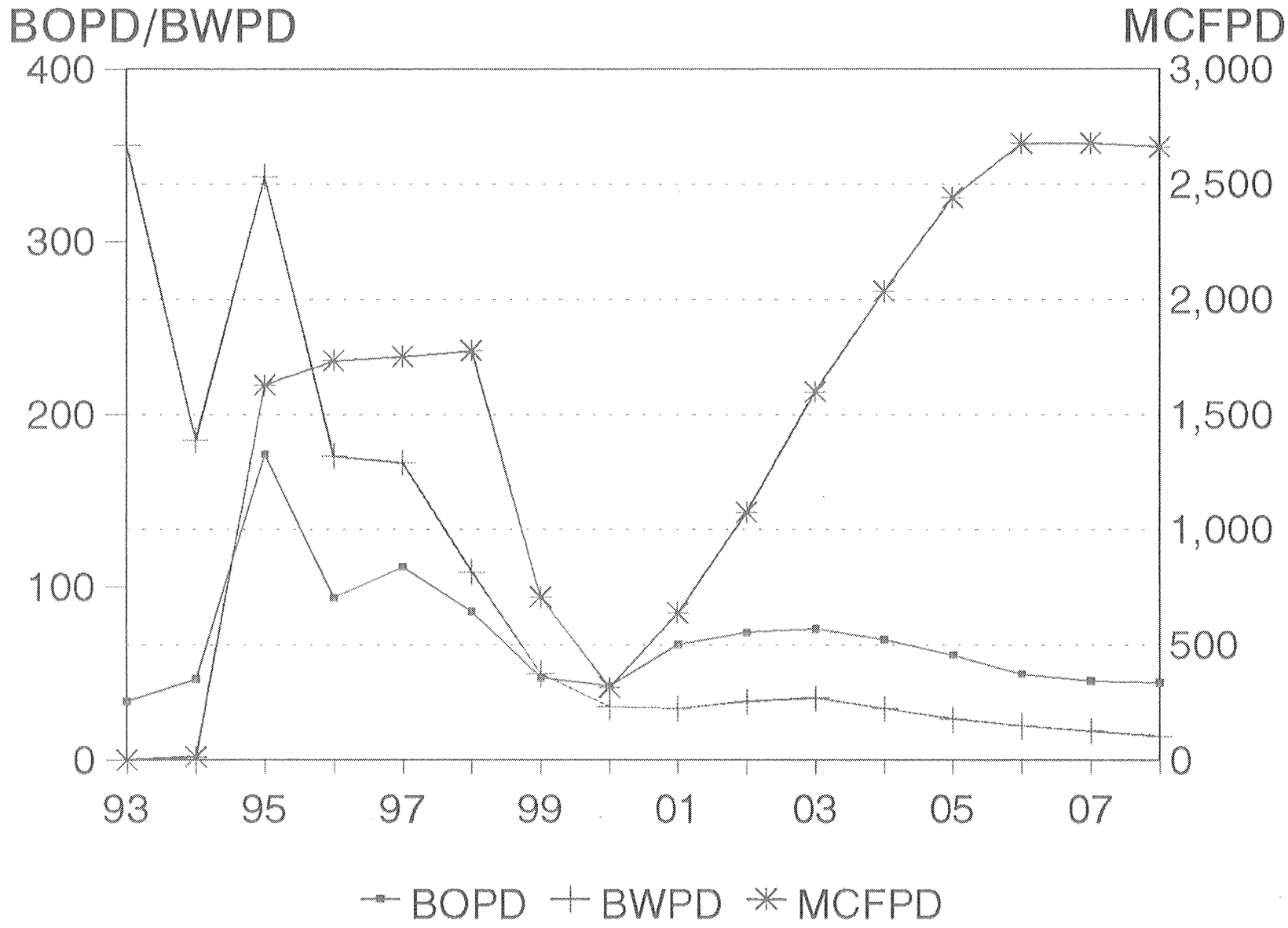
H. J. Kuhn Tr. 1 No. 14

CO2 Response



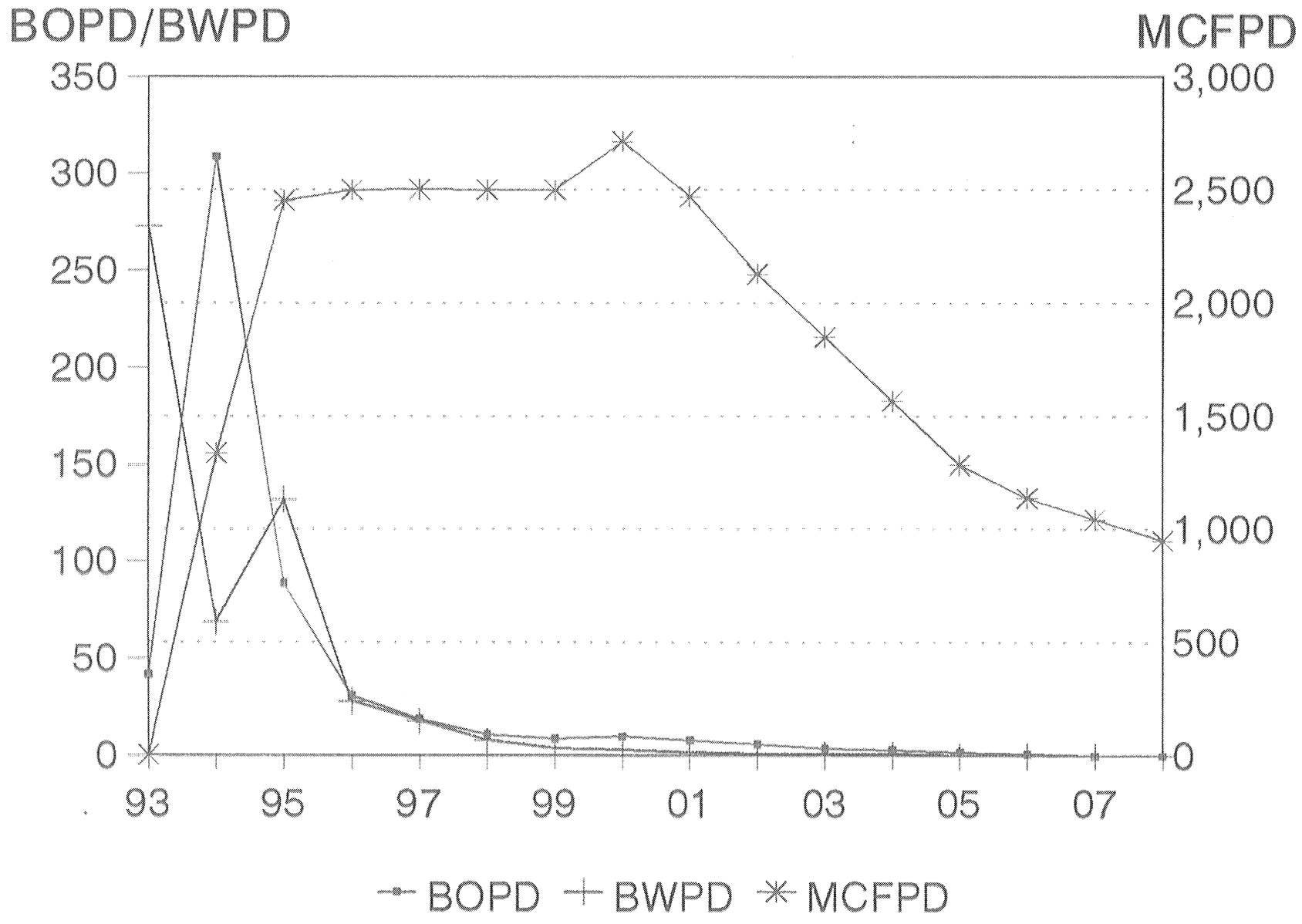
H. J. Kuhn Tr. 1 No. 15-R

CO2 Response



H. J. Kuhn Tr. 1 No. 33

CO2 Response



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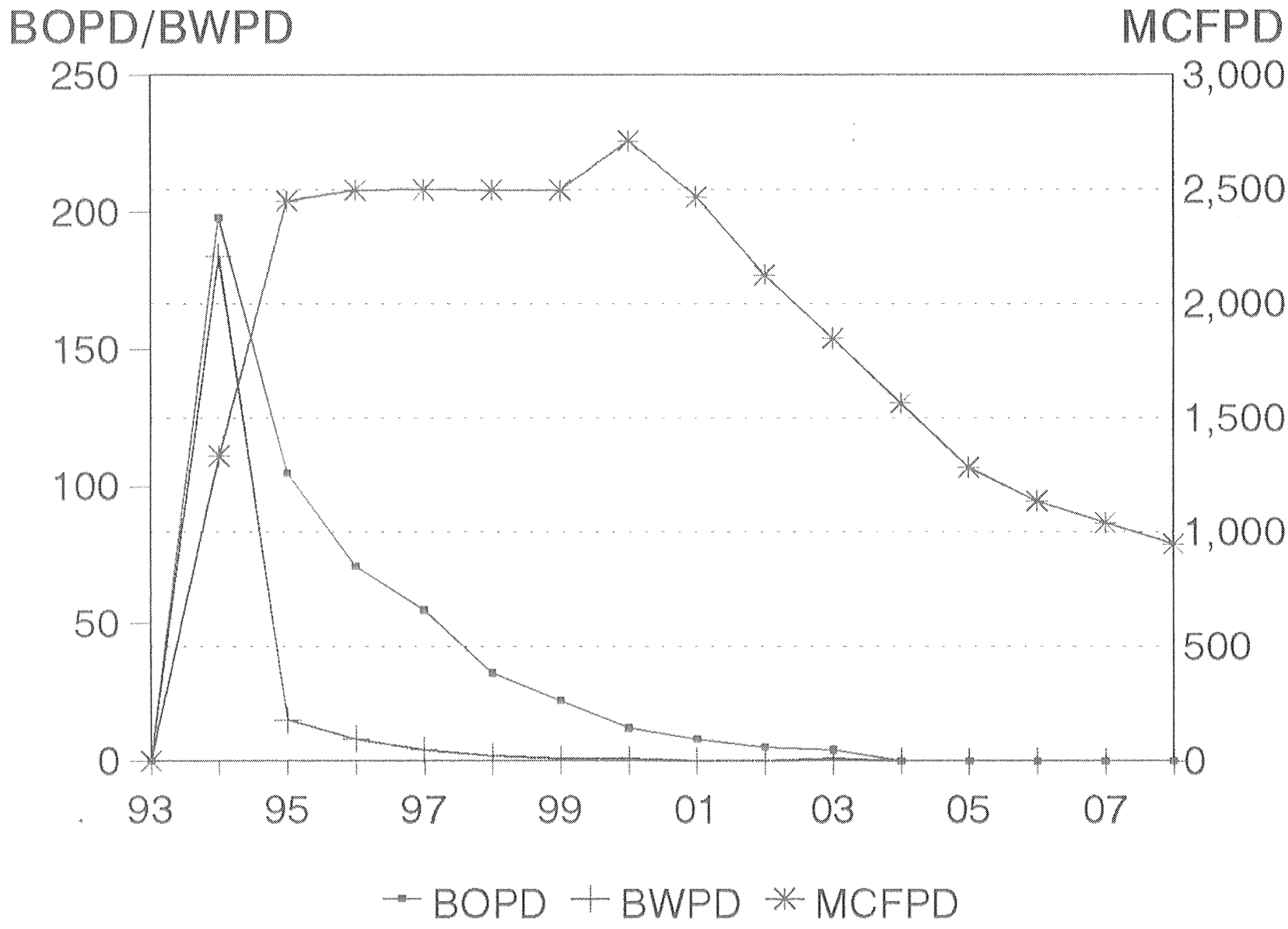

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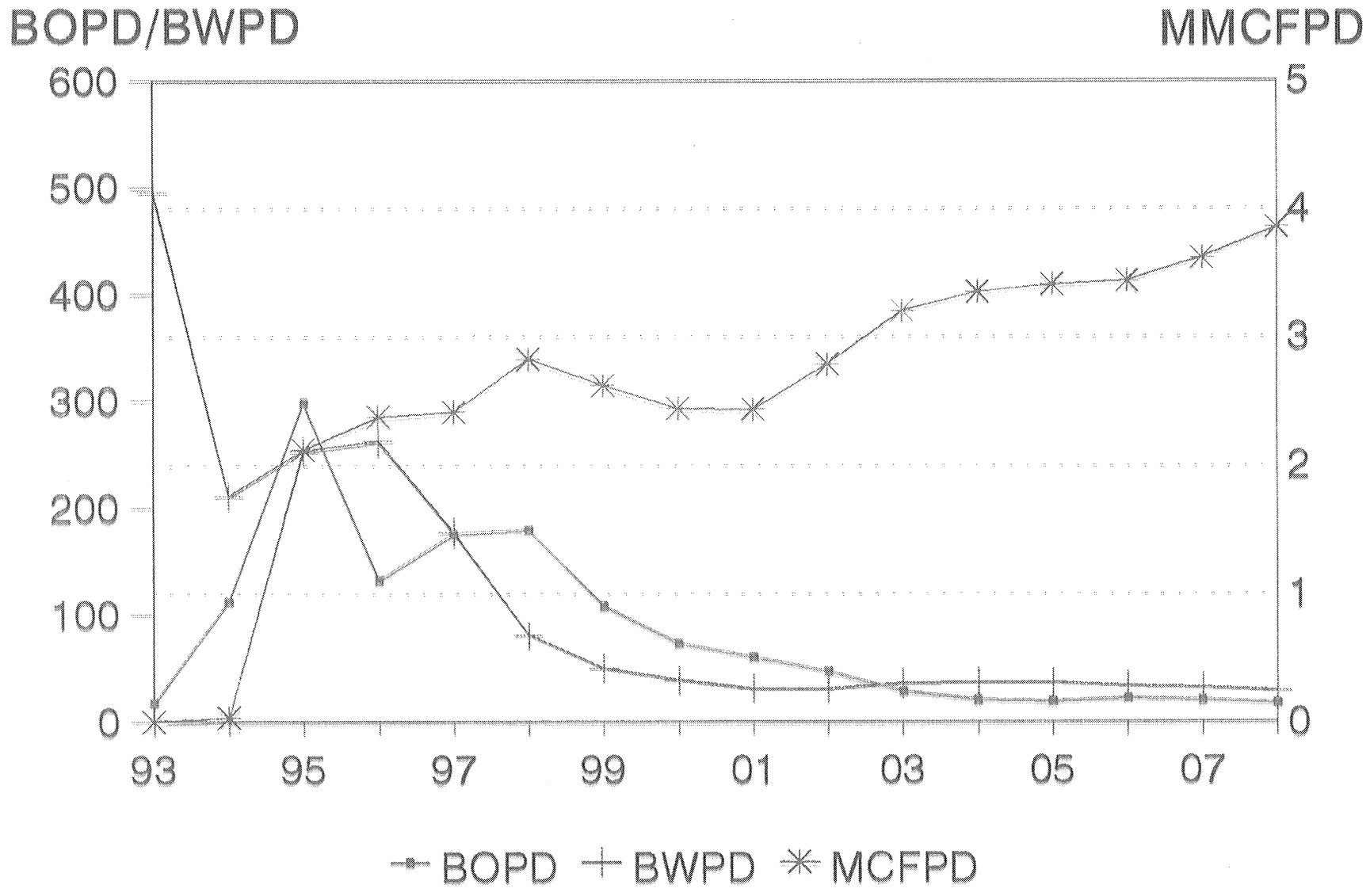

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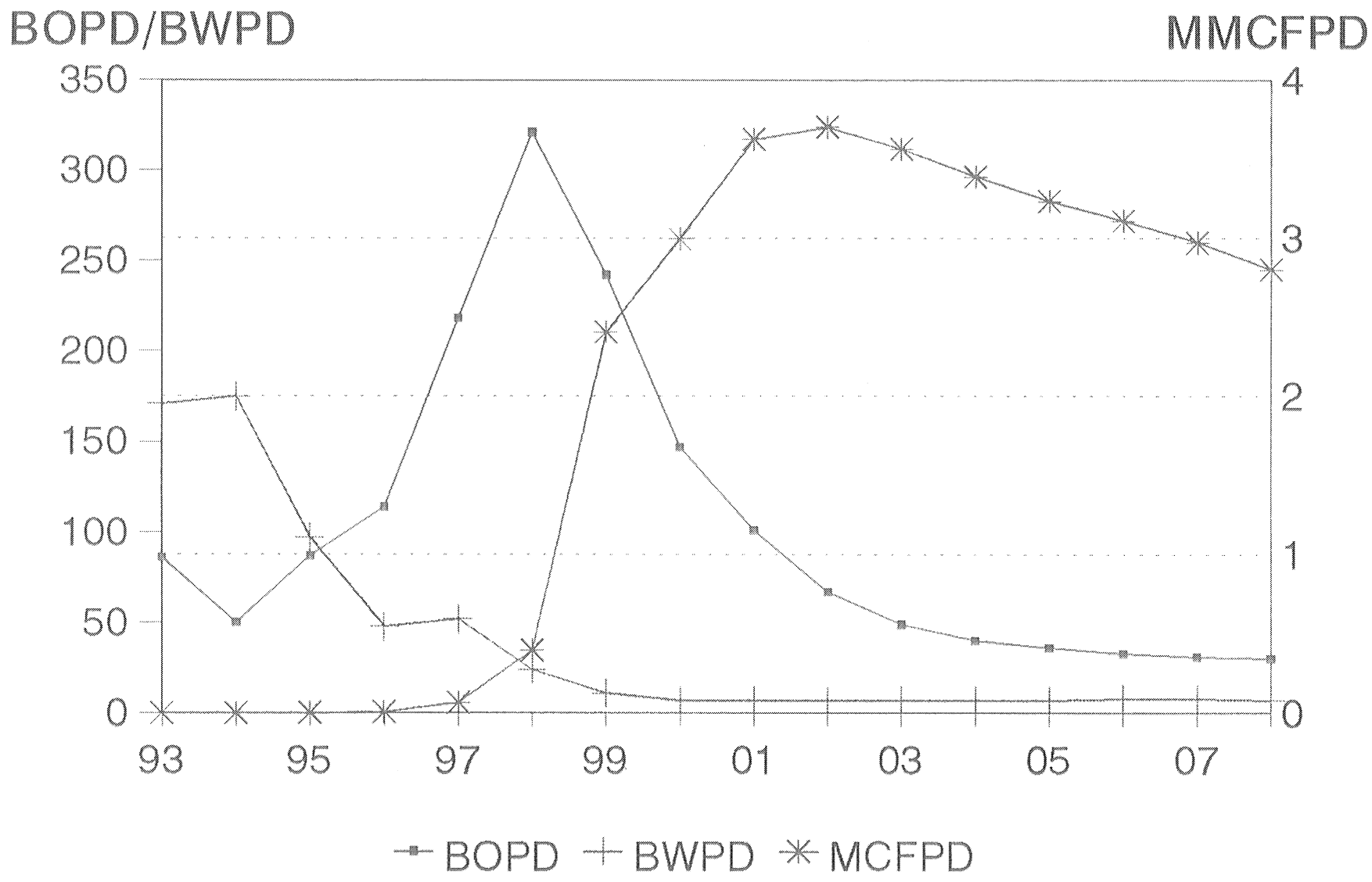

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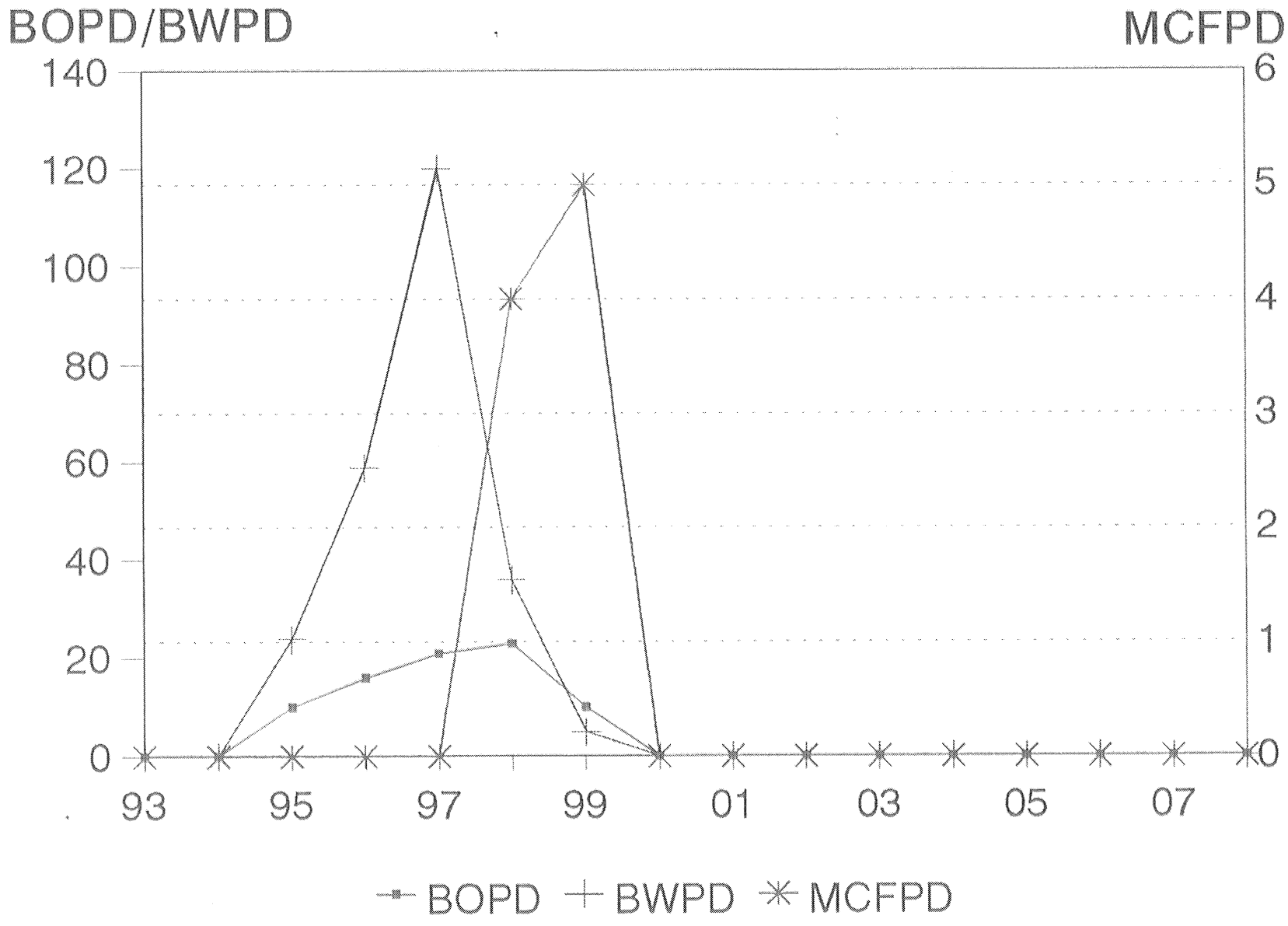
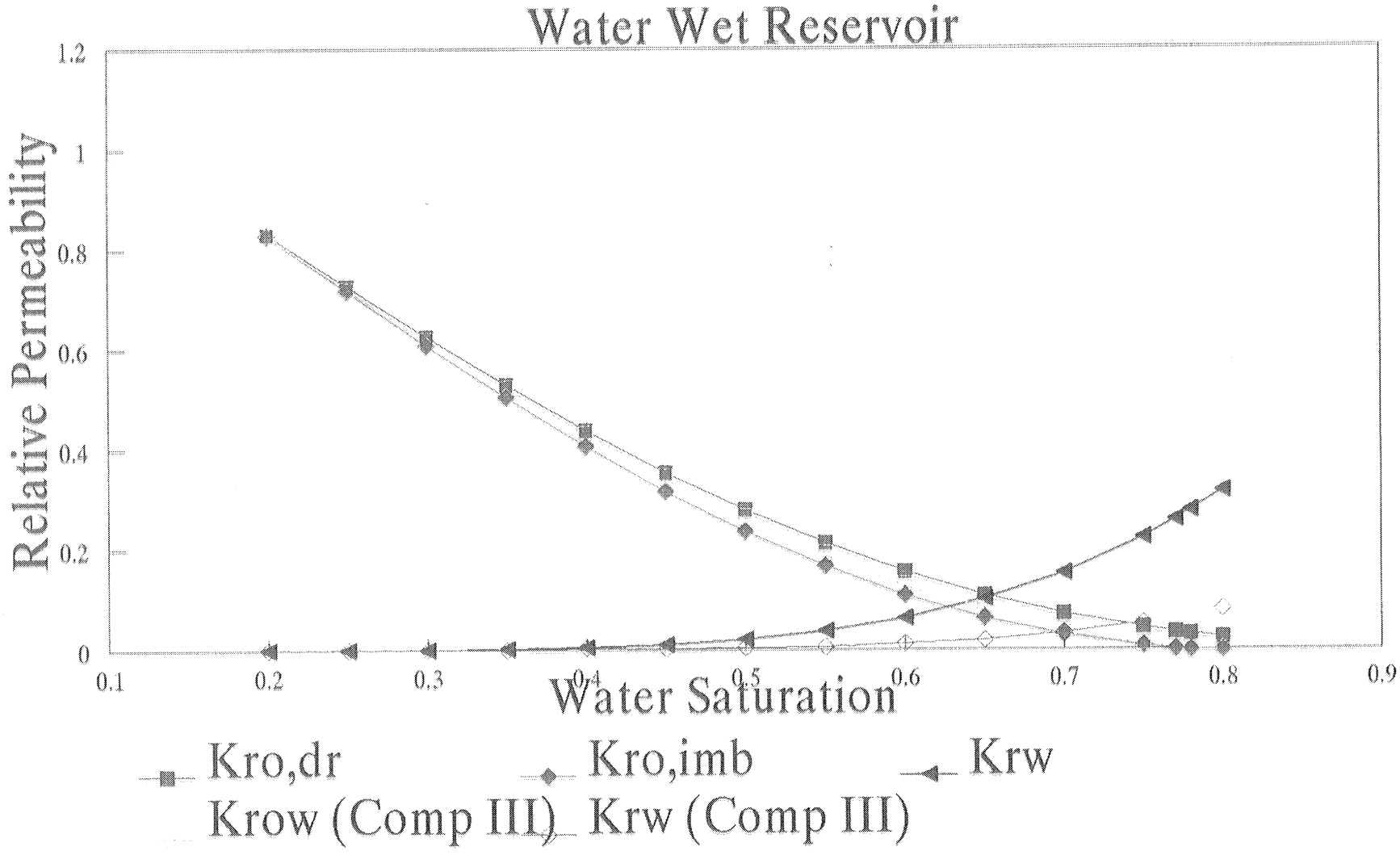
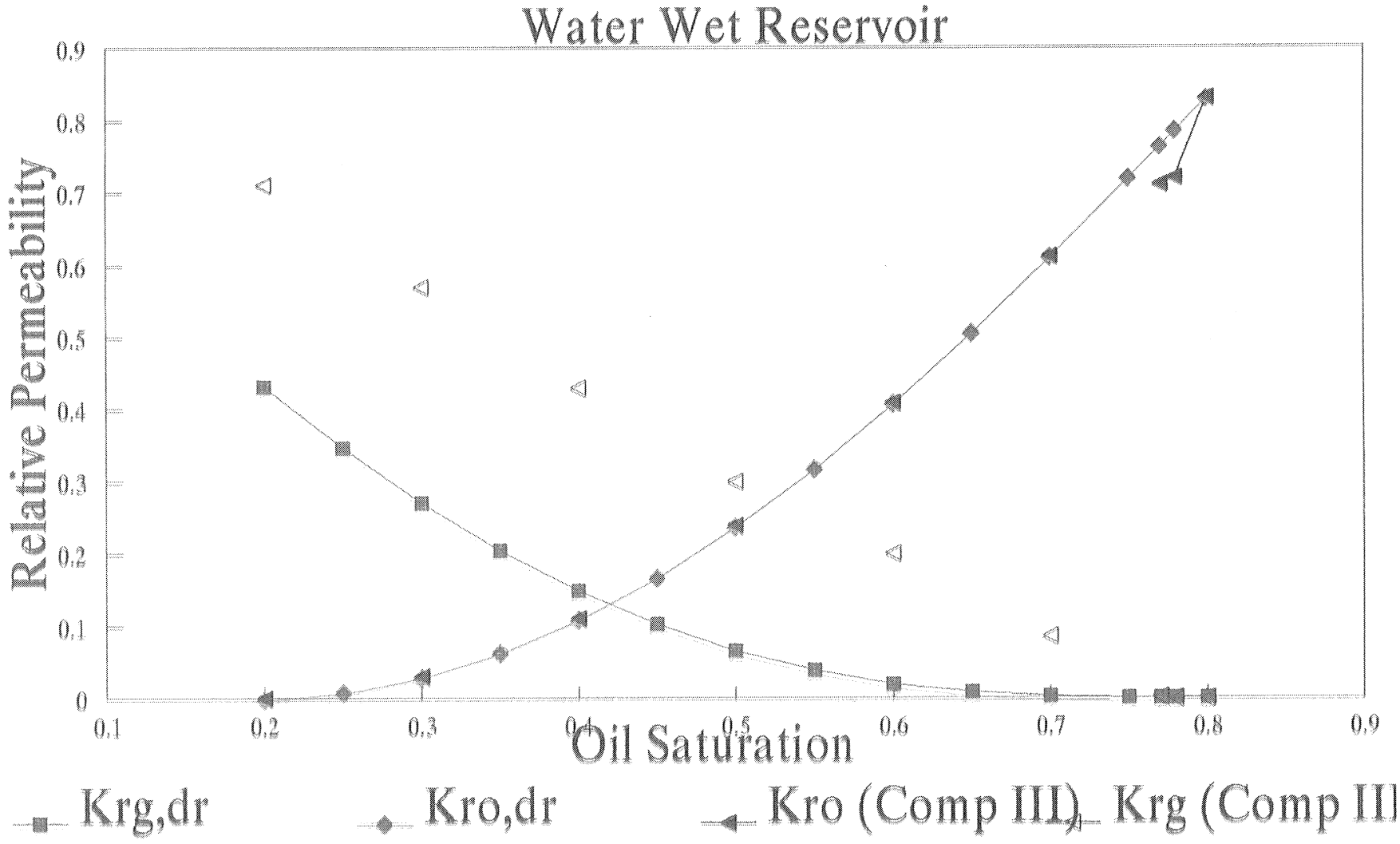


Oil – Water Relative Perm Curve



Gas – Oil Relative Perm Curve



FIELD-DERIVED COMPARISON OF TERTIARY RECOVERY MECHANISMS FOR MISCIBLE CO_2 FLOODING OF WATERDRIVE AND PRESSURE-DEPLETED RESERVOIRS IN SOUTH LOUISIANA

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Field-Derived Comparison of Tertiary Recovery Mechanisms for Miscible CO_2 Flooding of Waterdrive and Pressure-Depleted Reservoirs in South Louisiana

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SPE Members

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ABSTRACT

This paper describes two distinct tertiary recovery mechanisms that were observed in five CO_2 miscible field tests conducted in South Louisiana. A comparison between oil vaporization in water drive reservoirs, and oil banking in depletion drive reservoirs is presented. Other factors affecting the tertiary recovery such as CO_2 purity and injection patterns are discussed.

This paper will also define the Minimum Displaceable Oil Saturation (MDOS), a new concept in screening reservoirs for CO_2 flooding. The MDOS is the minimum oil saturation that must exist in the pore space in order to successfully form an oil bank economically in a miscible flood.

The presence of gas channels proved beneficial to enhancing oil recovery during cyclic CO_2 injection in depletion drive reservoirs. The solvent was able to penetrate deeper into the reservoir prior to any phase change taking place under miscible conditions at higher reservoir pressure.

The recovery mechanisms characterizing the miscible CO_2 floods were verified by a comprehensive reservoir monitoring program. Extensive logging and tracer programs were used to analyze the effects of heterogeneity in these layered reservoirs. The compositional changes of the produced fluids were determined from samples taken throughout the various stages of the projects. These analyzes resulted in the better understanding of CO_2/reservoir oil phase behavior.

The Push-Pull Flood process, recently patented, is discussed. The process involves initial simultaneous gas injection into all wells in the reservoir. This method utilizes opposing injection forces in the reservoir to increase CO_2 penetration and thereby reach additional oil that otherwise may never be contacted. The process is designed to improve vertical and horizontal sweep efficiencies as well as project's response time and cash flow.

References and illustrations at end of paper.

INTRODUCTION

Four of the five CO_2 floods were conducted in the Paradis Field and the other flood was in the Bay St. Elaine Field. The reservoirs flooded with CO_2 are listed in Table 1 along with their reservoir parameters. Both fields are located in South Louisiana as shown in Figure 1. Paradis is a land field located in St. Charles Parish, 25 miles southwest of New Orleans. Bay St. Elaine is an inland water field located in Terrebonne Parish, 65 miles southwest of New Orleans.

Production from these fields are from Miocene sandstone reservoirs overlying salt domes. These reservoirs are typical South Louisiana sandstones exhibiting high porosity, permeability, and API gravity. Maps and type logs for each of these reservoirs are shown in Figures 2 through 6. Drive mechanisms during primary production ranged from pure depletion to strong water drive.

The 8000' RE SU at Bay St. Elaine was chosen as a pilot to test the gravity stable miscible CO_2 flooding process in a steeply dipping reservoir [1]. All wells had watered out prior to updip CO_2 injection.

Paradis was selected in 1979 for CO_2 flooding because of its oil and reservoir characteristics as well as its proximity to potential CO_2 sources and existing pipelines. Originally two water drive reservoirs, Lower 9000' RM SU and No. 8 RA SU, were selected for CO_2 flooding [2]. They were nearly depleted of their 8.3 million stock tank barrels (STB) of primary production when the last remaining producing wells were worked over for updip CO_2 injection during the second half of 1981. Non-gravity-stable miscible CO_2 floods were conducted in these relatively flat reservoirs.

Carbon dioxide channeled across a fault into the Lower 9000' RA SU from the adjacent flood, the Lower 9000' RM SU. This resulted in downdip injection into a weak water drive reservoir that was nearly depleted. Well primary production was 309 thousand STB of oil. CO_2 response occurred in August 1984. Reservoir and fluid characteristics are the same as the Lower 9000' RM SU except for the drive mechanism and lower reservoir pressure.

The last Paradis CO_2 flood discussed in this paper was implemented in a depletion drive reservoir. The reservoir was depleted of its 140 thousand STB of primary production when CO_2 injection began. The 9500' RC-7 SU flood was designed using the Push-Pull Flood method with downdip injection. The injection and producing wells were discovered to be fault separated. The flood was then redesigned to be a reservoirwide Huff-Puff. The Push-Pull Flood process is explained later in the Future Plans section of this paper.

TERTIARY RECOVERY MECHANISMS

Two distinct recovery mechanisms, vaporization and banking, were observed when these five reservoirs were flooded with CO_2. Vaporization was observed as the major process in water drive reservoirs while banking occurred in depletion drive and partial water drive reservoirs. Water drive reservoirs generally have low residual oil saturation while depletion drive have higher residual oil saturation.

These observations are proven by the reservoirs' initial producing yields and oil API gravities. Reservoir yield is defined as STB of oil produced per million standard cubic feet (MMcf) of total gas produced. High initial yields were associated with reservoirs where oil displacement and banking was the dominant process. The API gravity was initially higher during vaporization and unchanged for banking as compared to the base oil as shown in Figure 7.

Vaporization

Vaporization through multicontact miscibility was observed as the primary mechanism for recovering oil in water drive reservoirs. The CO_2 extracts and vaporizes the various components of the oil starting with the light ends. As the CO_2 becomes more enriched with the light ends, it begins to strip the heavier oil into the CO_2 phase. This is occurring under miscible conditions or in the near miscible region.

Figure 8 shows a graph of API gravity versus time for well IF 64 in the Lower 9000' RM SU. The API gravity during primary production was 37 degrees. Initial production after CO_2 injection resulted in an API gravity between 50 and 60 degrees, thus proving that the lighter ends were vaporized first. The gravity gradually declined as more heavier ends were vaporized to produce an oil with a gravity near 40 degrees. Note that the gravity of the oil is still significantly higher than the base oil.

Even though vaporization recovers residual oil, it is inefficient and expensive because of the large amount of CO_2 required. Figure 9 shows the yield curves for the two reservoirs that experienced primarily vaporization - Lower 9000' RM SU and No. 8 RA SU. The original yield quickly stabilized at 65 and 25, respectively, with a steady exponential decline thereafter. The steady decline in yield and the constantly changing API gravity shows that a stable vaporization has taken place in the reservoir proving that the CO_2 is extracting the oil into the CO_2 phase.

Combination of Vaporization and Banking

The BSE 8000' RE SU project showed a combination of banking and vaporization. The project was specifically designed by our Technology Division to be a multicontact gravity stable flood. By controlling the frontal velocity in a steeply dipping reservoir and adding enrichment to the CO_2 mixture, we were able to achieve banking initially even though the residual oil saturation was low. The solvent injected was 84% (mole) CO_2, 11% methane, and 5% normal butane. The initial yields were in the banking region above 150, but they show a exponential decline towards the vaporization range below 100 as shown in Figure 10.

There is a good correlation between the API gravity and the yield as shown in Figure 11. The API gravity was not significantly affected when banking occurred in the high yield region. The API gravity increased with decreasing yield indicating vaporization.

Oil Banking

Oil banking is the most efficient process in miscible flooding. A miscible bank displaces all the moveable oil and a significant portion of the residual oil to waterflooding as it moves from the injectors to the producing wells. When a dense miscible fluid, such as CO_2, is injected into

an oil reservoir it will immediately vaporize some of the oil into the CO_2 phase. In order to form an oil bank economically, a Minimum Displaceable Oil Saturation (MDOS) must exist in the reservoir. This concept is discussed in the next section of this paper.

The Lower 9000' RA SU and 9500' RC-7 SU showed clear indications of a banking process taking place in the reservoirs. This is proven by the constant API gravity shown in Figure 7 and the high initial yield over 200 shown in the yield versus time curves in Figure 12.

The yield in the Lower 9000' RA SU was slightly erratic because of production problems, but it essentially stayed between 100 and 200 with no decline. A large oil production response occurred in the well in August 1984 when the CO_2 bank reached it. The data prior to that time represented primary production. The yield remained high during tertiary production and averaged about 150 throughout the remaining life of the well. The well was junked during a workover to replace the gravel pack setting. We anticipated the well would have continued to produce at a yield of 150 until the bank was produced. The yield would have then declined with the production of the trailing transition zone.

The initial yield in the 9500' RC-7 SU of 270 was the highest observed in the Paradis Field. Oil banking is the only mechanism that could cause such a high recovery efficiency. The yield steadily declined; however, in this instance the decline was due to the CO_2 expansion with continuing drop in reservoir pressure, rather than vaporization. Figure 13 shows the flowing tubing pressure of well IF 40 versus time. The well has been produced with a constant choke of 12/64 inch. The API gravity of the oil remained the same after CO_2 response as it was during primary production.

Another important observation in the 9500' RC-7 SU project is the water production caused by the injection of CO_2. During primary production the reservoir produced an insignificant amount of water - about 3,000 barrels. This is less than 1.5% of the total reservoir fluid produced. All of the water production occurred in the early stages of primary production. After CO_2 injection the well is making 10% to 15% water with a lower salinity indicating that some water vaporization is occurring in the reservoir. The CO_2 altered the relative permeability curves by lowering the critical water saturation, thus increasing the amount of recoverable oil.

MINIMUM DISPLACEABLE OIL SATURATION (MDOS)

The Minimum Displaceable Oil Saturation (MDOS) is defined as 'The minimum oil saturation that must exist in the pore spaces of the reservoir in order to successfully form an oil bank economically in a miscible flood'. It is clear from the field data that any miscible process should end up being a combination of vaporization and banking. The dominant process depends primarily on the oil saturation.

Oil banking was observed in reservoirs where the initial yield was 150 or greater. Oil vaporization was observed in reservoirs where the initial yields were less than 100. Initial yields from 100 to 150 range represents a transition zone between banking and vaporization. A yield of 150 or greater corresponds to the normal solubility of CO_2 in oil at reservoir conditions.

The lowest initial yield observed with banking was 150 in the Lower 9000' RA SU. The oil saturation of the reservoir when the CO_2 production began was calculated by volumetrics to be 34%. The estimated residual oil saturation to waterflood was calculated to be 24% based on sidewall core data and correlations for South Louisiana's reservoirs.

The MDOS was derived empirically from the above field data and has been observed to be about ten percent above the reservoir residual oil saturation to waterflooding, as shown in equation 1.

$$MDOS = Sor + 0.10 \quad \ldots\ldots\ldots \quad (1)$$

Since this observation has been derived from limited data points, refinement and corroboration of this definition is needed from laboratory data and other CO_2 floods.

The oil saturations and the depletion drive indices [3] for the four CO_2 floods at Paradis were calculated and plotted versus their initial yield and they are shown in Figures 14 and 15, respectively. Figure 14 indicates a strong correlation between the oil saturation of the reservoir and the initial yield. Figure 15 shows that reservoirs in which banking occurred had a depletion drive index of at least 0.5. Additional data is required to determine if banking can occur at a lower depletion drive index. These graphs can be used to predict the initial yield and the recovery mechanism that takes place during CO_2 flooding.

EFFECT OF GAS CHANNELS

Gas channels in the Lower 9000' RA SU and the 9500' RC-7 SU were beneficial in forming oil banks and resulting in efficient floods. This is contrary to the idea of performing CO_2 floods in reservoirs with high pressure that exceed the minimum miscibility pressure (MMP) in order to achieve miscibility and banking. As a result we had initially chosen reservoirs that were water drive to specifically avoid gas channels.

Since we could not achieve oil banking in these floods, we decided to flood a depletion drive reservoir that had gas channels as one of its characteristics.

The results from the 9500' RC-7 SU CO_2 flood in Paradis proved that the presence of gas channels are beneficial to enhancing oil recovery especially during cyclic CO_2 injection in depletion drive reservoirs. The CO_2 mixture penetrated deeper into the reservoir under immiscible conditions and contacted the maximum amount of available oil. Continuing CO_2 injection raised the reservoir pressure until it became miscible with the reservoir oil. The project was designed for the CO_2 to be injected under immiscible conditions and be produced from the same well under miscible conditions.

CO_2 injection began in the 9500' RC-7 SU, at a reservoir pressure of 800 psig, after depletion of its 140 thousand STB of primary oil. The flood was originally designed using the Push-Pull Flood method but was modified to be a reservoirwide Huff-Puff when the injection well was discovered to be isolated from the producing well.

Injection began in January 1989, and through May, 434 million cubic feet of a CO_2 mixture was injected. The composition of the injected gas was 81% (mole) CO_2, 2.5% nitrogen, and 16.5% C_1+. The CO_2 solvent fingered through the already existing gas channels, thus contacting additional oil in remote areas of the reservoir.

As the pressure began to increase and the CO_2 became more miscible in oil, the gas channels began to close. This induced more CO_2 to dissolve into the oil, aiding the formation of an oil bank. CO_2 injection continued until the reservoir pressure increased to 5200 psig, 1600 psig above the MMP and 550 psig above the original reservoir pressure. The reservoir was allowed to soak for 45 days before being opened for production.

An oil response occurred after four days of producing dry gas having essentially the same composition as the injected mixture. The well's production stabilized at the end of three weeks it was flowing clean oil @ 178 STB per day at 1500 psig on a 12/64 inch choke making 731 thousand cubic feet of gas with 80% of it CO_2. The API gravity was 38.0 degrees, the same as prior to CO_2 injection, and a high yield of 270.

Oil banking was confirmed by this well because it continues to produce at normal API gravity and high yield. During the nine months of production to date it has produced over 25 thousand STB and is expected to produce 60 thousand STB for the first CO_2 injection cycle. At least two more cycles are planned for this reservoir.

FIELD MONITORING PROCEDURES

An extensive monitoring program was implemented to monitor the development of the CO_2 floods in the Lower 9000' RM SU and the No. 8 RA SU. In addition to monitoring production response, we also used pulsed neutron logs, injectivity surveys, radioactive tracers, and produced fluid samples to analyze the progress of the floods in these heterogeneous multi-layered reservoirs. Only data from the Lower 9000' RM SU flood will be presented; similar data is available from the No. 8 RA SU.

The production response by all the wells across the reservoir showed that we had good horizontal or areal response. This was further proven by the radioactive tracer analyzes. A different tracer was injected with the CO_2 mixture into each injection well. More than one tracer was detected in all but one of the producing wells proving an efficient horizontal sweep in the reservoir. Greater concentrations of tracer were observed as expected in the producing wells closer to the injectors.

The injectivity surveys run in the injection wells and the pulsed neutron logs in the producing and monitor wells indicated that the CO_2 was penetrating the entire sand. The layers with higher permeability showed a preferential movement of CO_2 as expected.

The vertical conformance of the CO_2 mixture was best shown by the pulsed neutron logs and tracer response. Figure 16 shows the changes in the pulsed neutron logs for well IF 20 with CO_2 response. The sigma curves are shown for both the base log and after CO_2 response. The second log was run in October 1982, four months after CO_2 response occurred. It shows the greatest changes in the more permeable layers. The tracer response shown in Figure 17 is for the same well, IF 20. The various peaks show the time when different members of the sand responded to CO_2.

Fluid samples from the produced streams were continuously analyzed in order to detect changes in the oil, water and gas produced.

Analysis of the oil composition shown in Figure 18 for well IF 5 proves that stable vaporization was taking place. The oil produced in February 1983, six months after CO_2 breakthrough, shows a much higher concentration of lighter ends, C_7 to C_{10}, than the base oil. Higher concentrations of heavier hydrocarbons, C_{11} to C_{17}, were detected three years later in December 1985. It is also noted that even after four years of production, the vaporized oil was still richer in lighter ends than the base oil.

Water analysis was useful in detecting wellbore communication between reservoirs. Iron counts were used in monitoring corrosion

rates.

The gas was analyzed using a gas chromatograph to monitor the mixture composition in order to maintain miscibility. This was abandoned after we stopped purchasing CO_2 in 1986. Currently all the produced gas is being recycled into the reservoirs. The concentration of the CO_2 continues to decline as more dissolved gas is liberated. The current concentration of the combined mixture of all the CO_2 floods is 81% (mole) CO_2, 2.5% N_2 and 16.5% C_1+.

Impurities in the CO_2 have a detrimental effect on the recovery efficiency for vaporization. Laboratory studies showed that a change of impurities from 3 to 10% N_2 equivalent would reduce vaporization efficiencies by 17%. Effect of impurities on CO_2 vaporization efficiency is shown in Figure 19.

FUTURE PLANS : PUSH-PULL FLOOD PROCESS

We are currently implementing a new CO_2 flood designed using the Push-Pull Flood process. Recently patented [4] as a more efficient method for enhanced oil recovery, the Push-Pull Flood process can be used in various reservoirs regardless of size or geometry. The only requirements are that a minimum of two wells are in communication and the MDOS is satisfied. The process can be used in water drive reservoirs, but it is better suited for depletion drive reservoirs with the presence of gas channels and high oil saturation.

CO_2 is initially injected into all the wells in the project. Injection continues into the injection wells, but is terminated in the producing wells after a specified period, normally six months. The length of the injection period depends on injection rate, reservoir pressure, distance between wells, as well as economical considerations. The producing wells in the reservoir are shut-in for a month or two to allow the CO_2 to soak and are then opened for production. If they continue to produce dry gas for more than a week, then they are shut-in for another two or three weeks.

One advantage of the Push-Pull Flood process is to improve the horizontal sweep efficiency. As the CO_2 is injected into all wells, the resulting opposing injection forces in the reservoir causes the CO_2 to be diverted and penetrate areas that may not be contacted otherwise. Figure 20 shows a map of a typical South Louisiana reservoir and the additional area that will be contacted using this process. This will solve a common problem of poor horizontal sweep efficiency in miscible CO_2 floods. [5]

Another advantage of the Push-Pull Flood process is the improvement in vertical sweep efficiency. Since the injected CO_2 follows the path of least resistance, it will penetrate the most permeable layer. As injection continues, the pressure increases in that layer and automatically diverts the CO_2 into the less permeable layers. These layers normally have a higher oil saturation because of poor sweep efficiency during primary recovery. The automatic redistribution of the injectant will also reduce the volume of CO_2 recycled through a thief zone in multi-layered reservoirs. This is in lieu of doing polymer profile corrections in the injection wells.[6,7]

Producing wells also benefit from the Push-Pull Flood process. The weak acid effect of the CO_2 will improve the well's productivity. This combined with the higher reservoir pressure due to multiple injection wells will increase the producing rate.

We attempted to perform the Push-Pull Flood method in the 9500' RC-7 SU but found the injector to be fault-separated from the producer. The project was modified to be a reservoirwide Huff-Puff project using the producing well, thus proving the flexibility of the various CO_2 methods. The Push-Pull Flood process will be implemented in the near future.

The Push-Pull Flood process should reduce production response time and increase the ultimate recovery, thus improving project economics and cash flow. This process eliminates one major obstacle against CO_2 flooding, namely the long lead time prior to oil response.

CONCLUSIONS

1. For the conditions studied, the presence of a Minimum Displaceable Oil Saturation (MDOS) is the most important criteria to the formation of an oil bank.

2. The reservoirwide miscible CO_2 huff-puff process improved the recovery efficiency as well as project's response time and cash flow in pressure depleted reservoirs.

3. Efficient CO_2 floods in South Louisiana can be conducted in depletion drive and partial water drive reservoirs. This results in high yield and low GOR production in light crude.

4. Gas channels are beneficial to CO_2 flooding in depletion drive reservoirs because it provides a path for the CO_2 to penetrate deeper and contact additional oil.

5. The current oil saturation and the depletion drive index are two important criteria in screening potential reservoirs for CO_2 flooding. These factors determine the magnitude of reservoir response to CO_2 injection.

6. CO_2 is capable of mobilizing residual water, thus altering the water relative permeability curve by lowering the end point, and causing an increase in oil recovery.

NOMENCLATURE

C_1+ = Natural gas or methane and other gaseous hydrocarbons
C_7 = Heptane
C_{10} = Decane
C_{11} = Undecane
C_{17} = Heptadecane
CO_2 = Carbon Dioxide
F = Fahrenheit
MMcf = Million cubic feet
N_2 = Nitrogen
pCi/l = Pico Curie per liter
S_{or} = Residual oil saturation to waterflooding, fraction
STB = Stock tank barrel

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SI METRIC CONVERSION FACTORS

API Grav	141.5/(131.5 + API Grav)	= g/cm^3
barrel	x 1.589 873 E-01	= m^3
cubic foot	x 2.831 685 E-02	= m^3
°F	$(T_{oF} - 32)/1.8$	= °C
inch	x 2.54* E-02	= m
mile	x 1.609 344 E+03	= m
psig	x 6.894 757 E+00	= kPa

* Exact conversion

TABLE 1. RESERVOIR PARAMETERS

RESERVOIR NAME		LWR 9000' RM SU	NO.8 RA SU	LWR 9000' RA SU	9500' RC-7 SU	BSE 8000' RE SU
DRIVE MECHANISM		WATER	WATER	PARTIAL WATER	SOLUTION GAS	WATER
POROSITY	(%)	25.8	27.2	26.0	24.0	32.9
PERMEABILITY.	(md)	770	795	500	252	1480
TEMPERATURE.	(F)	205	192	198	192	164
INITIAL PRESS.	(psig)	3950	4460	3950	4575	3627
PRESS. BEFORE CO2	(psig)	3650	4250	1779	798	3627
IRREDUCIBLE WAT SATURATION	(%)	20	19	25	25	15
DIP ANGLE	( )	8	6	10	9	36
GRAVITY	(API)	37	39	38	38	36
OIL SATURATION BEFORE CO2	(%)	25	19	34	45	20
INJECTED GAS COMPOSITION	(% CO2)	97	90	97	82	84
	(% N2)	3	10	3	2.5	0
	(% C1+)	0	0	0	15.5	11
	(% C4+)	0	0	0	0	5

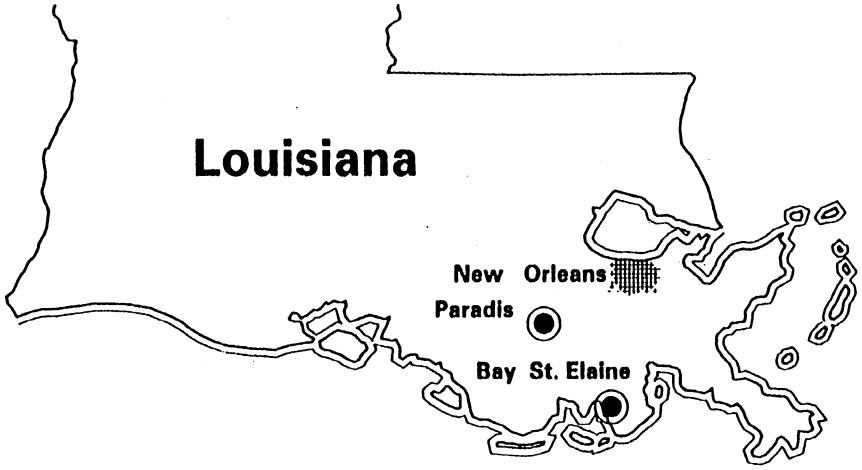

Fig. 1 – LOCATION MAP

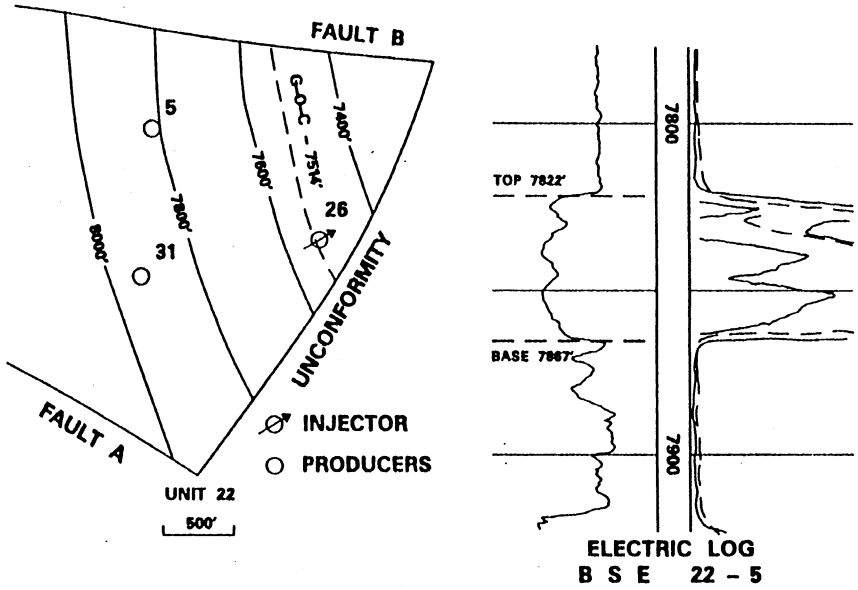

Fig. 2 – BSE 8000' RE SU

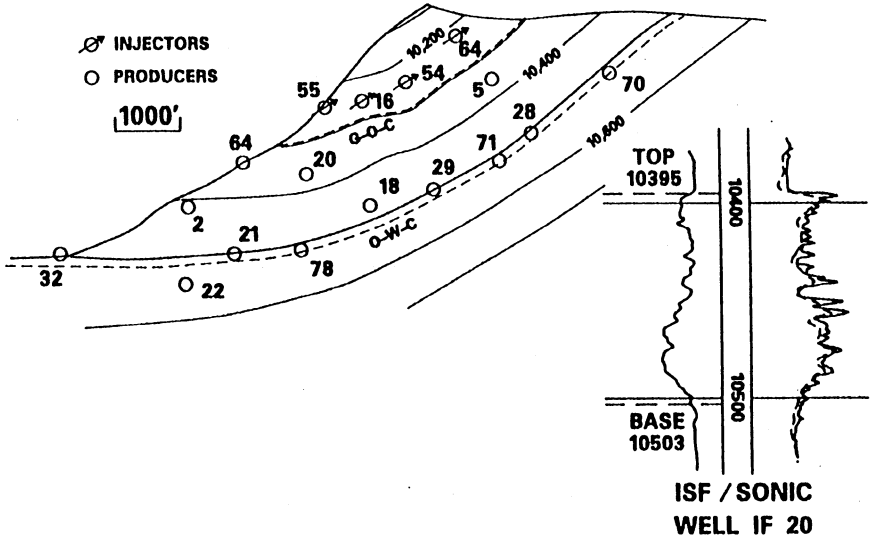

Fig. 3 – LOWER 9000' RM SU

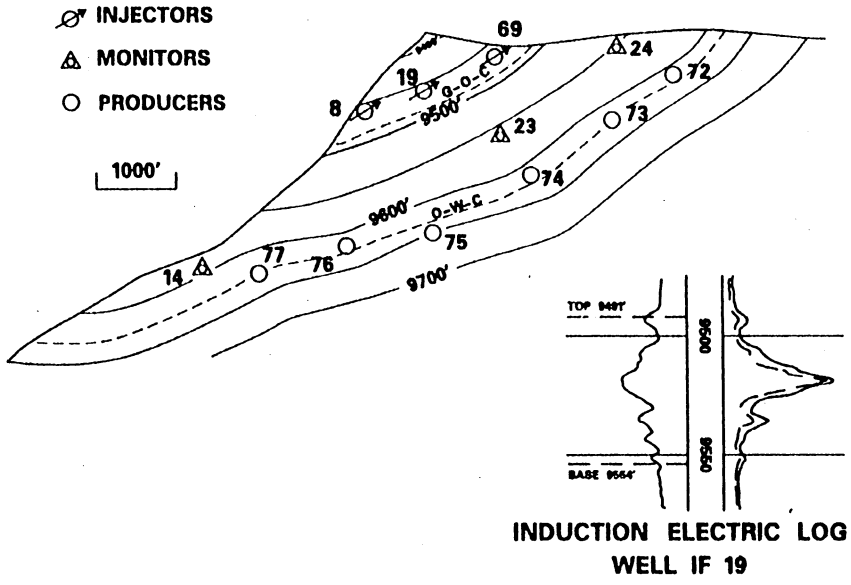

Fig. 4 – NO. 8 RA SU

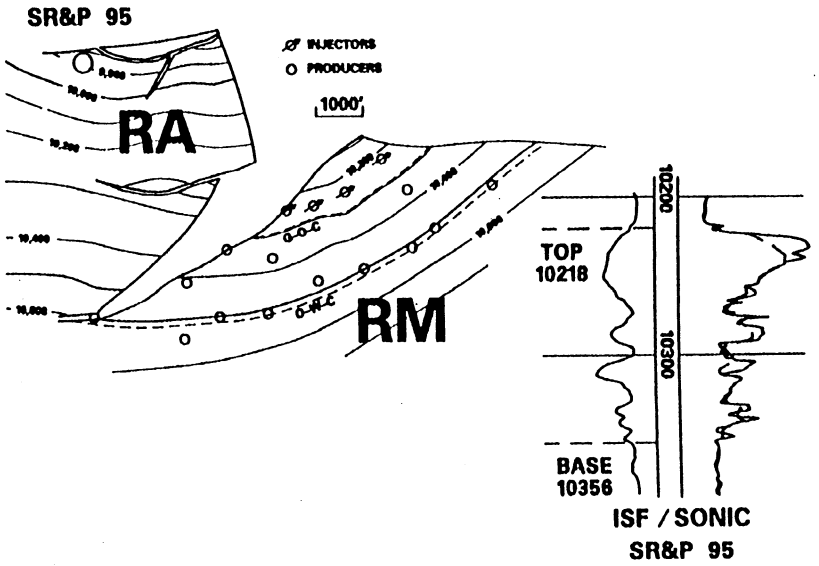

Fig. 5 – LOWER 9000' RA SU

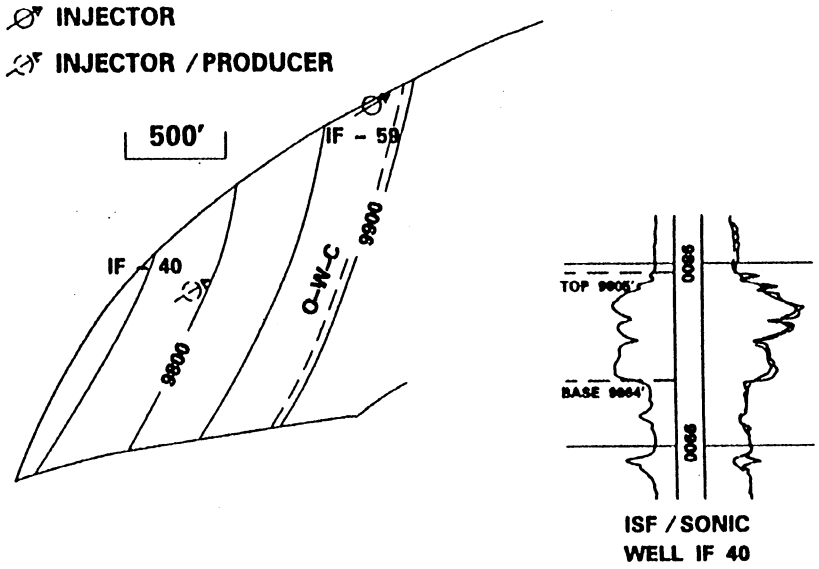

Fig. 6 – 9500' RC–7 SU

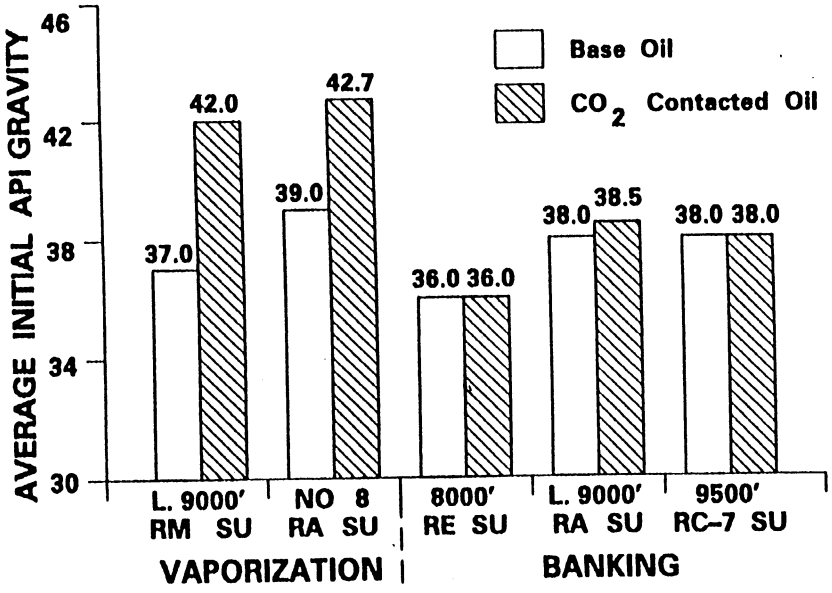

Fig. 7 – CHANGE IN API GRAVITY

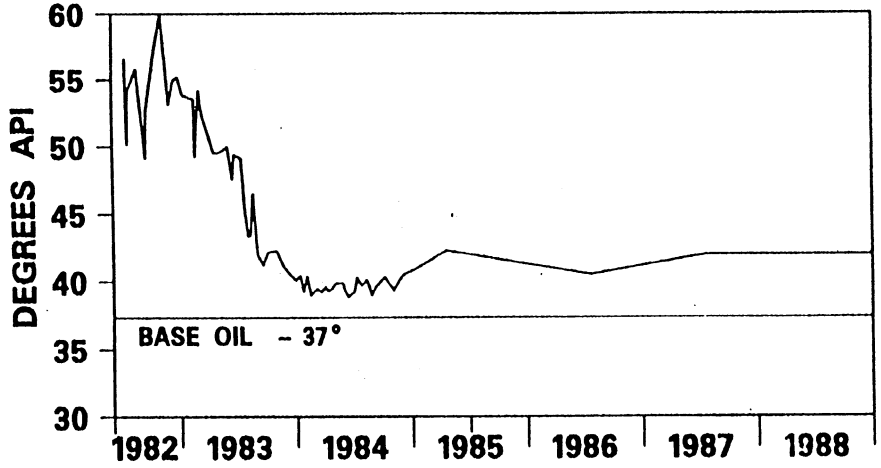

Fig. 8 – API GRAVITY CHANGES VAPORIZATION

LOWER 9000' RM SU – IF 64

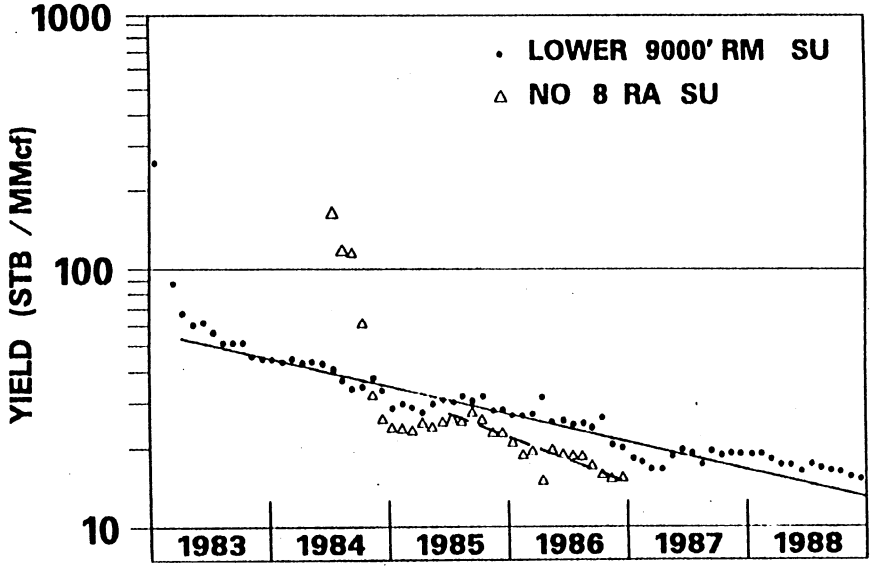

Fig. 9 – YIELD VS. TIME
VAPORIZATION

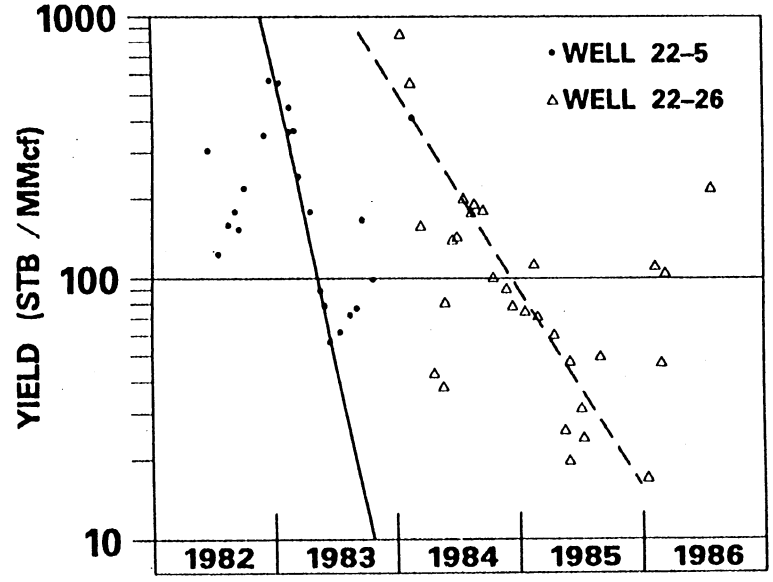

Fig. 10 – YIELD VS. TIME
BSE 8000' RE SU

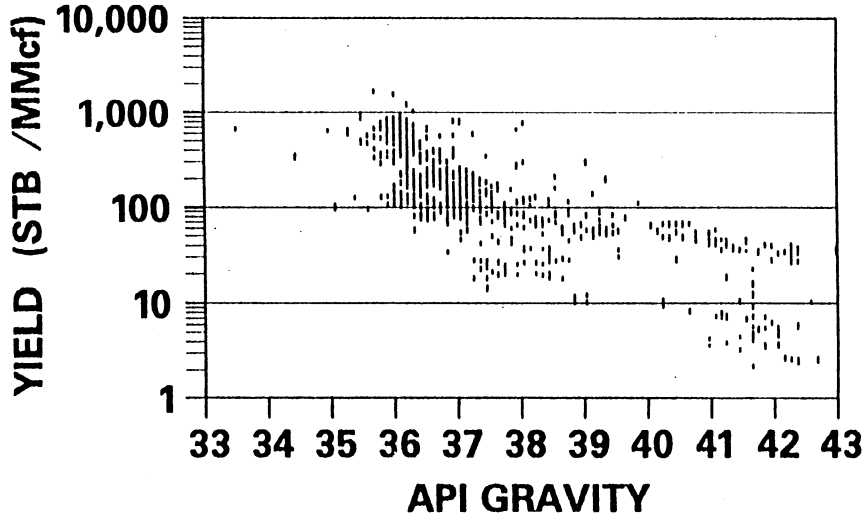

Fig. 11 – YIELD VS API GRAVITY
8000' RE SU

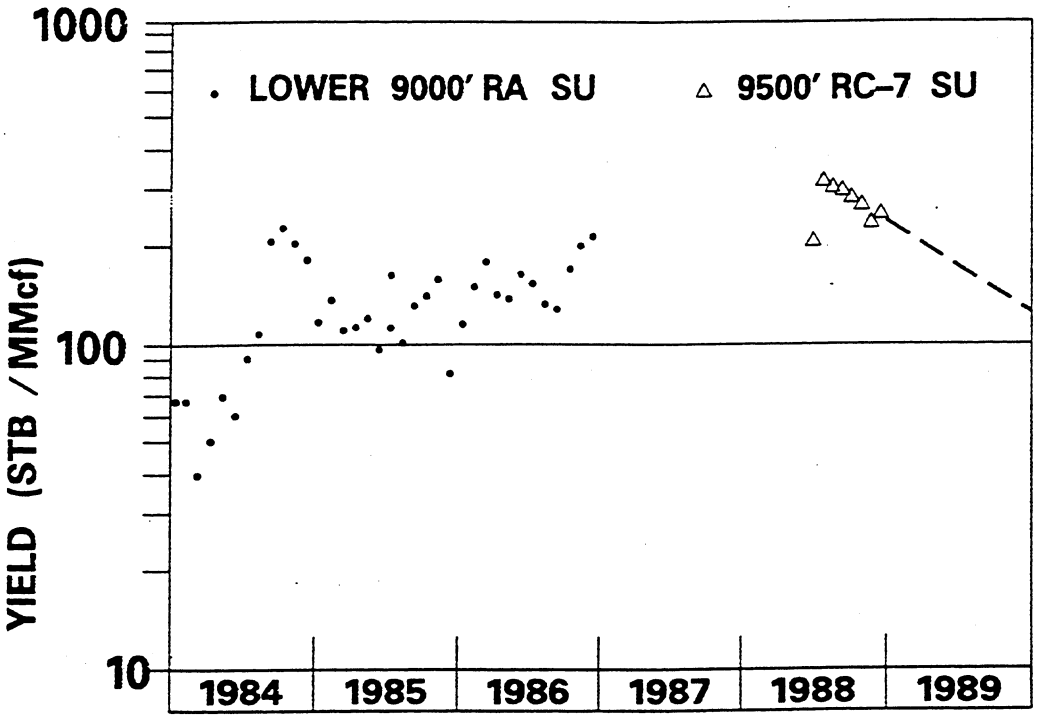

Fig. 12 – YIELD VS. TIME
BANKING

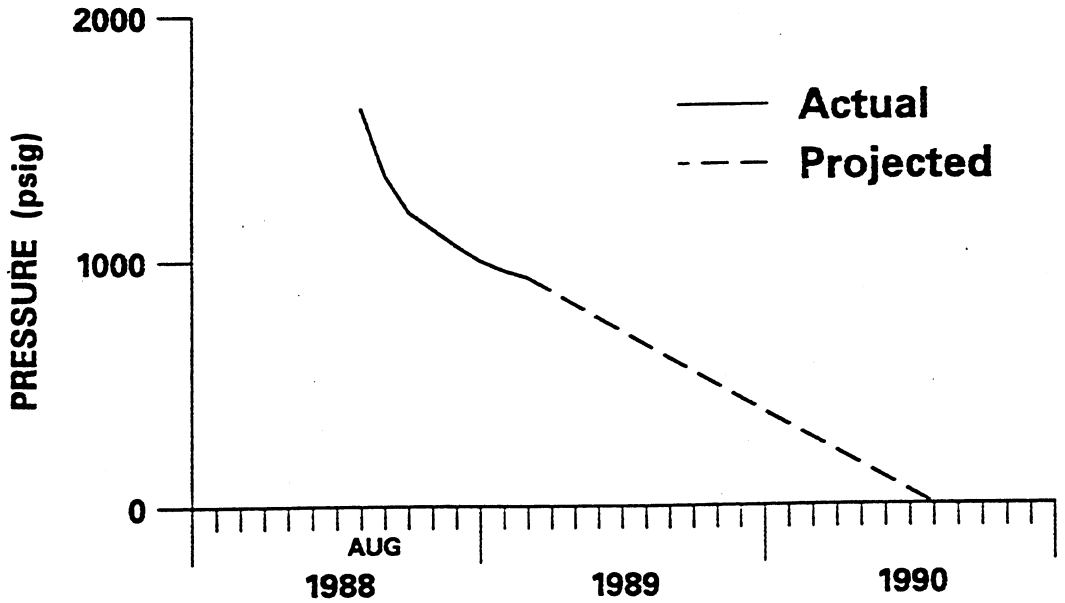

Fig. 13 – FLOWING TUBING PRESSURE
9500' RC-7 SU – IF 40

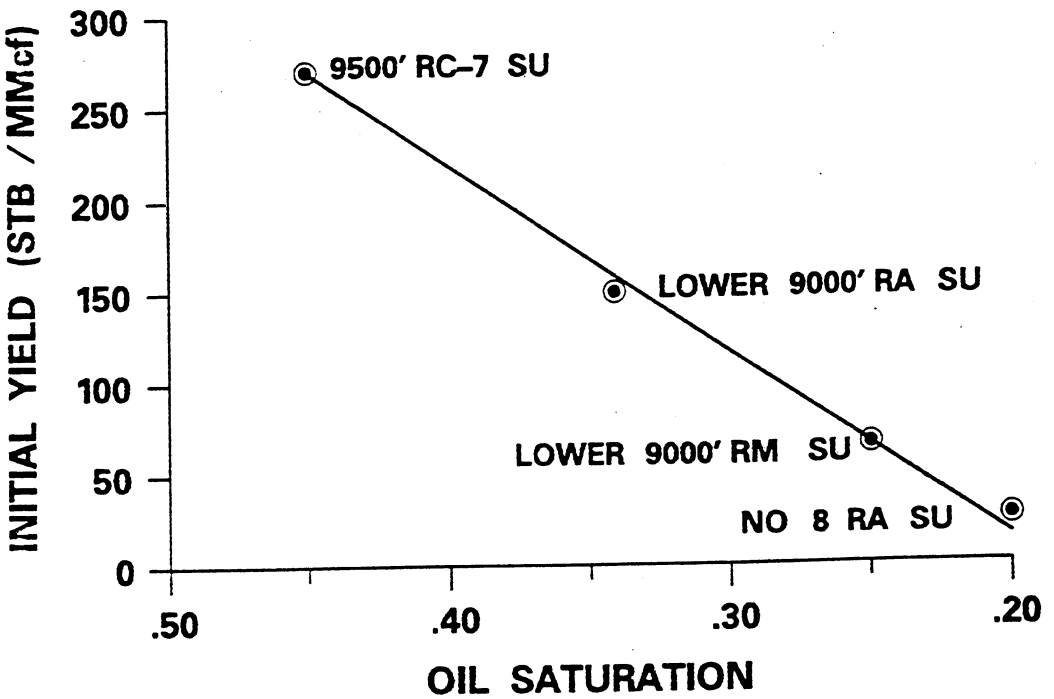

Fig. 14 – INITIAL YIELD VS. OIL SATURATION

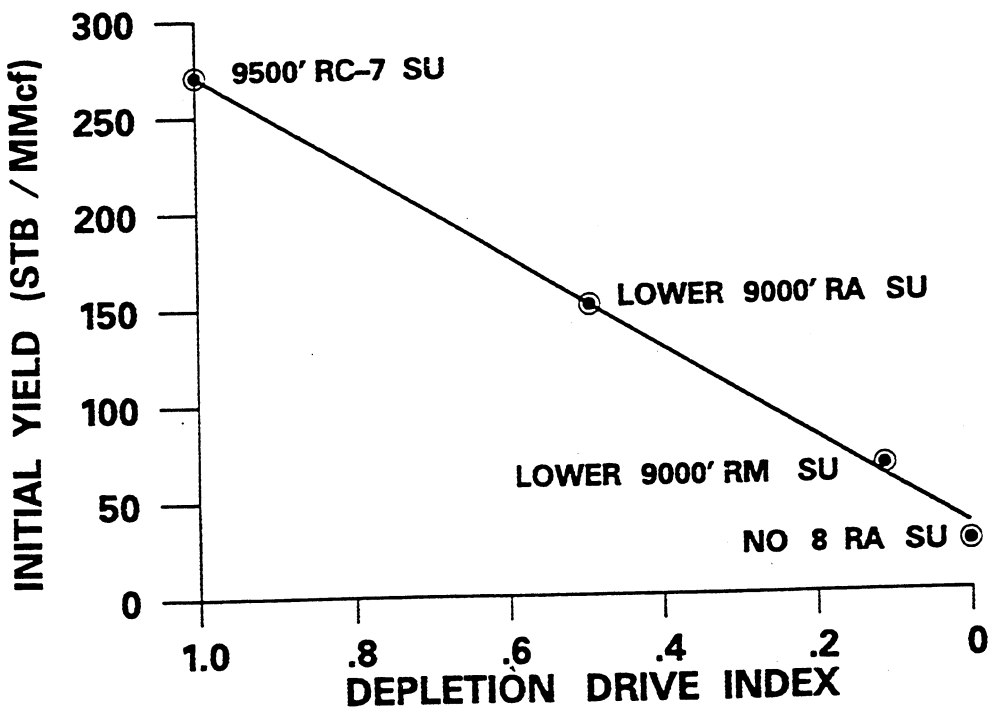

Fig. 15 – INITIAL YIELD VS. DRIVE INDEX

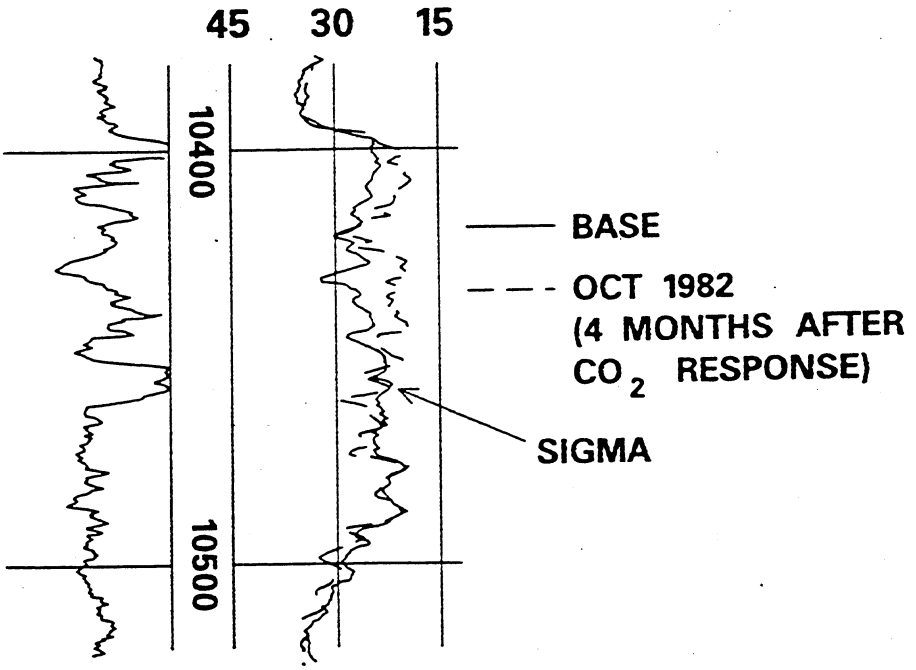

FIG. 16 – PULSED NEUTRON LOGS
LOWER 9000′ RM SU – IF 20

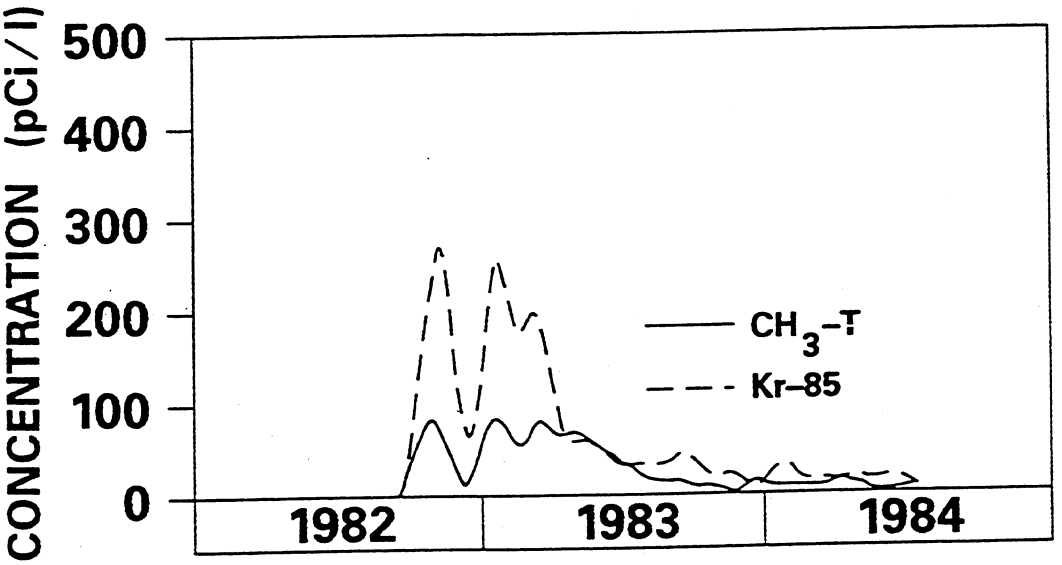

Fig. 17 – TRACER RESPONSE
LOWER 9000′ RM SU – IF 20

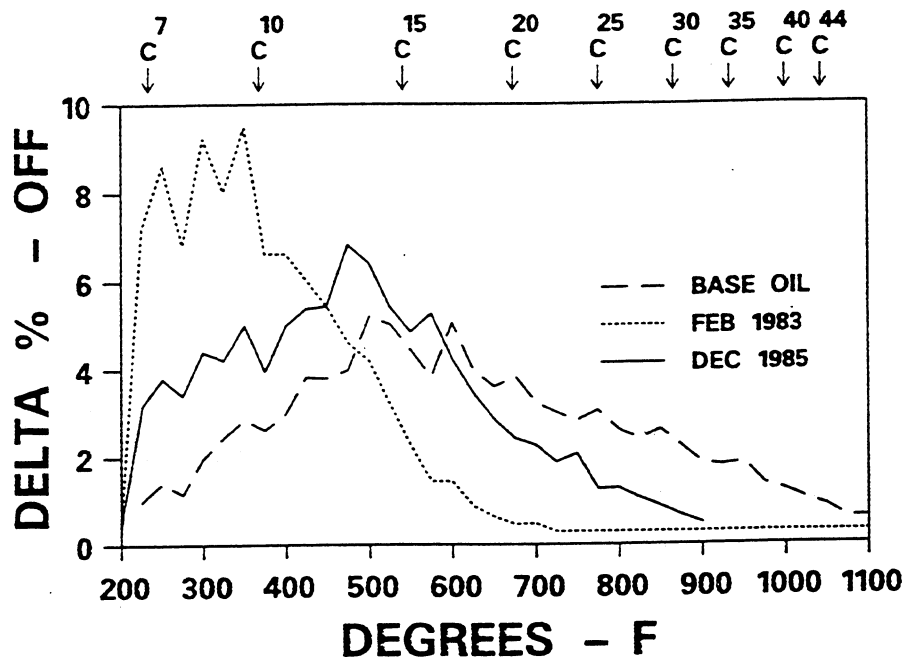

Fig. 18 – OIL COMPOSITIONAL CHANGES

LOWER 9000' RM SU – IF 5

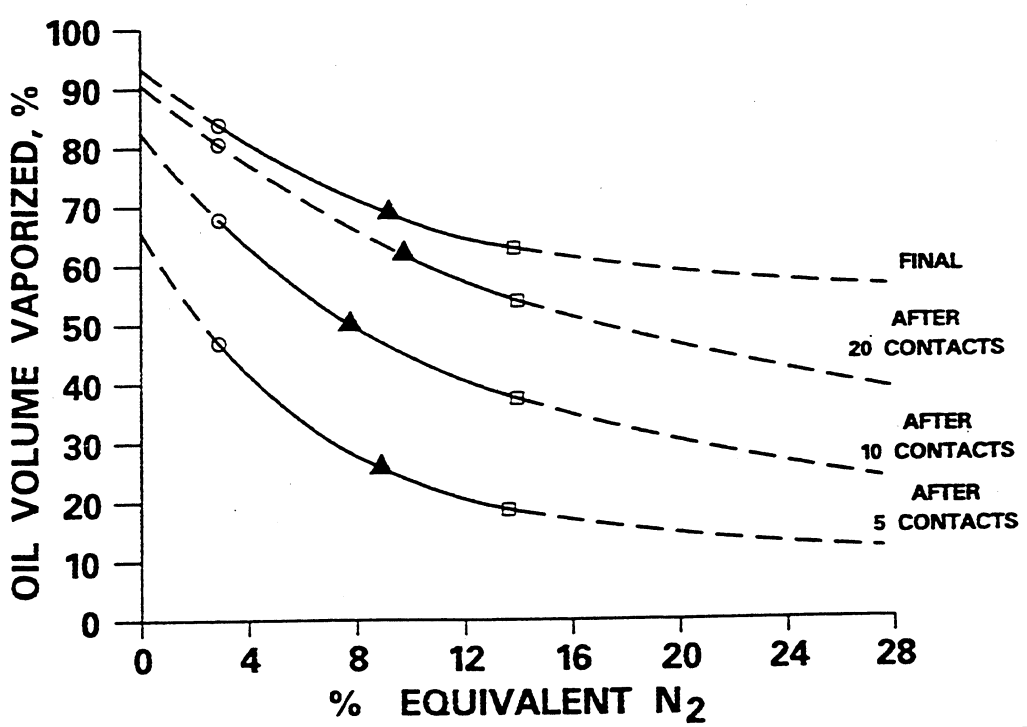

Fig. 19 – EFFECT OF IMPURITIES ON CO_2 VAPORIZATION EFFICIENCY

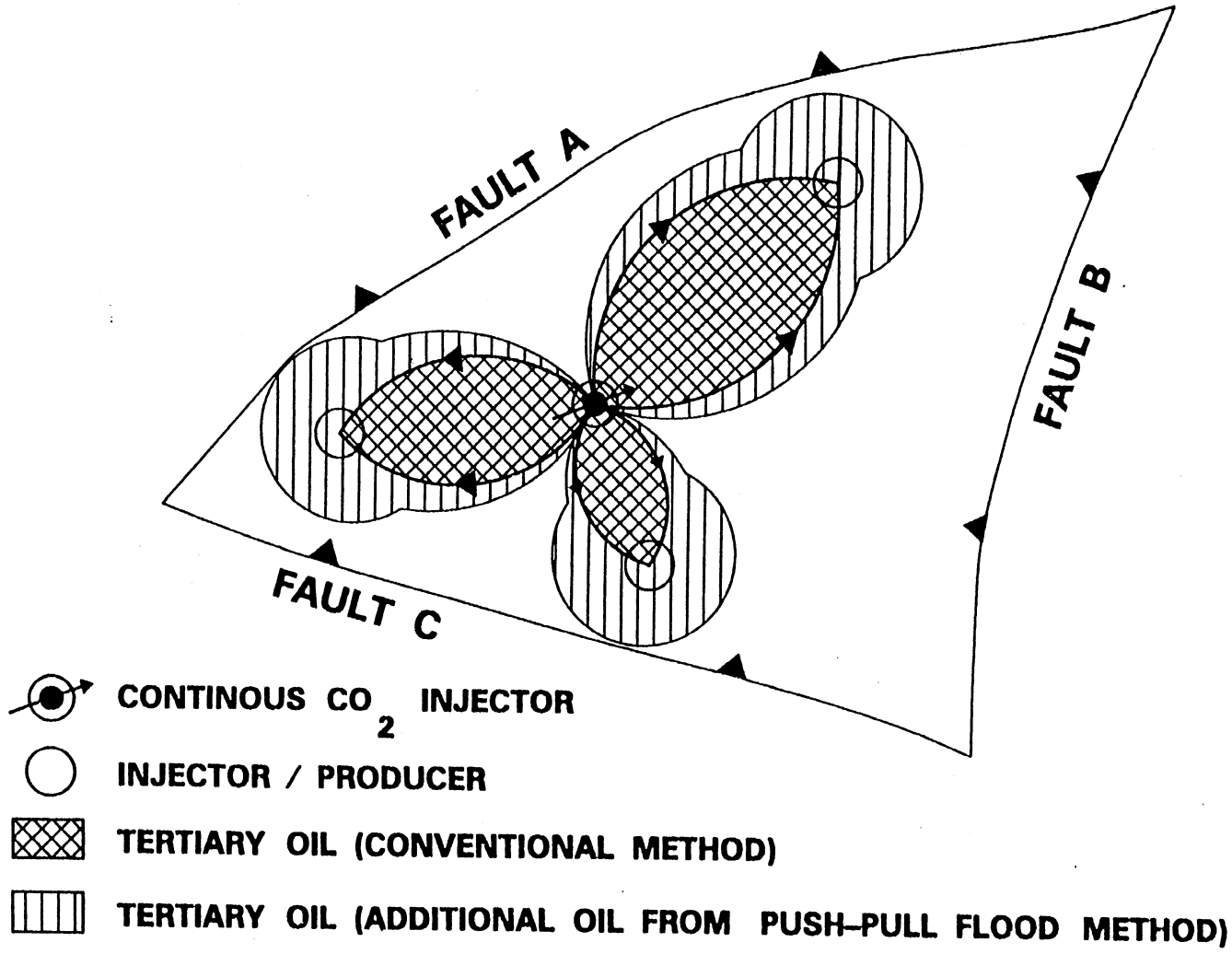

Fig. 20 – MISCIBLE PUSH–PULL FLOOD

PHASE 1 - CO_2 SWELLING/SOLUBILITY STUDIES FOR RESERVOIR FLUIDS OF THE PORT NECHES FIELD, H.J. KUHN #33 WELL ORANGE COUNTY, TEXAS

PHASE 1 - CO_2 SWELLING/SOLUBILITY STUDIES FOR RESERVOIR FLUIDS OF THE PORT NECHES FIELD, H. J. KUHN #33 WELL ORANGE COUNTY, TEXAS

PREPARED BY: _____
M. W. WIDENER

_____
T. M. VU

REPORT NO. 91-XXX

PROJECT 502-90-1395 CONFIDENTIAL 1991

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EXECUTIVE SUMMARY

A carbon dioxide flood has been proposed for the Port Neches Field, Orange County, Texas. At the request of the CO_2 Group, Harvey, Louisiana swelling/solubility and viscosity reduction experiments were conducted. Stock tank oil from the H. J. Kuhn #33 Well and CO_2 at reservoir conditions were used in the initial phase of this study. This same stock tank oil was recombined with a synthetic gas to approximate the original reservoir fluid in the second phase.

These tests are run to determine the physical properties of various mixtures of reservoir fluid and CO_2. These properties are necessary to define the CO_2-hydrocarbon interaction coefficients used in compositional reservoir simulation. The tests showed:

Significant hydrocarbon liquid phase swelling

Significant viscosity reduction

Minimal increase in density

INTRODUCTION

This work is in support of the proposed CO_2 EOR project in the Port Neches Field, Orange County, Texas. The purpose of this study is to determine the change in physical properties that will result from the addition of CO_2 to Port Neches Field reservoir fluid. These tests are run at reservoir temperature and pressures. Experimental determination of these values is necessary to define the CO_2-hydrocarbon interaction coefficients used in compositional reservoir simulation.

Little information is available on the properties of the original fluids from the Port Neches Field. The current producing gas-oil ratio is approximately 11 scf/stb. The reservoir fluid used in this portion of the study was the produced stock tank oil to represent the depleted reservoir fluid.

The current reservoir temperature is approximately 165°F. The current reservoir pressure is approximately 1865 psia.

CONCLUSIONS

Concentrations of 0 to 84.71 mole % CO_2 were bubble point fluids. These mixtures resulted in a:

92.2 % increase in saturation pressure volume.

82.5 % decrease in saturation pressure viscosity.

3.6 % increase in saturation pressure density.

Concentrations of 91.16 and 95.04 mole % CO_2 were dew point fluids. The actual dew point pressure for the 95.04 mole % concentration was not observed since it exceeds the maximum test pressures (8000 psia).

FUTURE WORK

This completes first phase of the CO_2 phase behavior study of the Port Neches Field, H. J. Kuhn #33 Well, Orange County, Texas EOR Study. The second phase will be completed in the near future.

DISCUSSION

The Port Neches Field is under consideration for CO_2 EOR. Oil samples were collected from the H. J. Kuhn #33 Well. Little information is available on the properties of the original fluids from the Port Neches Field. The current producing gas-oil ratio is approximately 11 scf/stb and the reservoir has been depleted to approximately 50 psi. The current reservoir temperature is approximately 165°F. The current reservoir pressure under waterflood is approximately 1865 psia.

The reservoir fluid used in this portion of the study was the produced stock tank oil. This was used to represent the depleted reservoir fluid. Oil samples were collected from the H. J. Kuhn #33 Well. The experimentally determined bubble point for the stock tank oil was approximately 15 psia at 165°F.

The hydrocarbon analysis and properties for the stock tank oil used in the current study are given in Table 1. All EPTD compositions reported are based on chromatographic analysis. The formation volume factor reported in table 3 is based on 100.0 weight % of the original synthesized live oil being produced as stock tank oil.

Swelling/Solubility Measurements

Swelling/solubility measurements were made on 7 separate mixtures of live oil and CO_2 at the reservoir temperature of 165°F. The composition was varied from 0 to 95.04 mole % CO_2. Bubble point systems included 0, 11.57, 29.82, 49.61, 69.74, 79.50, and 84.71 mole % CO_2 mixtures. Concentrations of 91.16, and 95.04 mole % CO_2 resulted in dew point fluids. A dew point pressure was not attained at test pressures for the 95.04 mole % CO2 fluid due to the limitations of the windowed cell.

The results are given in Tables 2 - 19 and in Figs. 1 - 5. The data in Tables 3 - 19 were smoothed and interpolated to give values at even pressure increments. The raw laboratory data are included in an appendix.

Critical Point

A liquid-vapor critical point of 87 mole % CO_2 and 4525 psia at 165°F has been estimated. This point is evident in the transition from bubble point to dew point fluid mixtures and was estimated by construction of the pressure-composition diagram for 165°F.

Graphical Presentation

Figure 1 shows the conditions of pressure and composition which

result in a given volume fraction of hydrocarbon liquid. The liquid-vapor critical point has been estimated. The iso-vol lines represent the liquid phase volume %, the balance being vapor.

Figures 2 show the pressure necessary to achieve a given liquid volume % for each of the mixtures. Cross plotting these individual mixtures enables one to develop the phase envelope presented in Figure 1.

Figures 3 and 4 show relative volumes (V_P/V_{SAT}) as a function of pressure for the mixtures.

Figure 5 shows the results of the viscosity reduction tests.

TABLE 1

HYDROCARBON ANALYSIS OF STOCK TANK FLUID USED IN CURRENT PVT STUDY
EXTENDED ANALYSIS - PORT NECHES FIELD, H. J. KUHN #33 WELL

Component	Well Stream Mole %
Nitrogen	0.00
Carbon Dioxide	0.00
Hydrogen Sulfide	0.00
Methane	0.00
Ethane	0.00
Propane	0.00
i-Butane	0.00
n-Butane	0.04
i-Pentane	0.00
n-Pentane	0.10
Hexanes	0.26
Heptanes	1.74
Octanes	2.64
Nonanes	5.00
Decanes	6.22
Undecanes	6.58
Dodecanes	6.89
Tridecanes	8.01
Tetradecanes	7.82
Pentadecanes	6.69
Hexadecanes Plus	48.01
Total	100.00

Composition based on GC analysis with capillary column. Katz and Firoozabadi molecular weights (JPT, November, 1978) used to calculate component mole percent.

Mole weight stock tank oil = 246
API gravity stock tank oil @ 60°F/60°F = 34.6
Density of stock tank oil @ 60°F = 0.8501 g/cc

Calculated mole weight heptane plus fraction = 247
Calculated mole weight hexadecane plus fraction = 340

TABLE 2

PORT NECHES FIELD, H. J. KUHN #33
SWELLING SOLUBILITY TEST SUMMARY
Properties at Saturation Pressure and 165°F

Mole % CO_2	Saturation Pressure (psia)	Swelling Index	Density (g/cc)	Viscosity (cp)
0.0	15*	1.000	0.8114	2.40
11.57	198*	1.019	0.8148	----
29.82	580*	1.064	0.8203	----
49.61	1150*	1.156	0.8257	----
69.74	2070*	1.383	0.8285	----
79.50	3115*	1.650	0.8331	----
84.71	3970*	1.922	0.8406	0.42
91.16	5780**	2.726	0.8470	----
95.04	***	----	----	----

*Bubble point pressures.

**Dew point pressure.

***Unable to determine dew point pressure due to windowed cell pressure limitations.

TABLE 3

FLUID PROPERTIES: PORT NECHES FIELD
H. J. KUHN #33 WELL - STOCK TANK OIL
TEMPERATURE = 165°F

Pressure (psia)	Relative Volume[1]	Liquid Volume %[2]	Viscosity (cp)
15*	1.0000	100.0	2.40
50	0.9998	100.0	2.41
100	0.9996	100.0	2.42
250	0.9989	100.0	2.46
500	0.9978	100.0	2.53
1000	0.9954	100.0	2.66
2000	0.9908	100.0	2.92
3000	0.9862	100.0	3.18

[1]Volume of fluid at pressure relative to the volume of fluid at saturation pressure.

[2]Volume of liquid at pressure relative to the total volume of fluid at that pressure.

*Bubble point pressure. Density at bubble point = 0.8114 g/cc. Formation volume factor at bubble point pressure = 1.0478 reservoir bbls/stock tank bbl (assuming 100.0 wt % reservoir fluid being produced as stock tank oil).

TABLE 4

CALCULATED COMPOSITION OF 11.57 MOLE % CO_2 MIXTURE
PORT NECHES FEILD, H. J. KUHN #33 WELL

Component	Well Stream Mole %
Nitrogen	0.00
Carbon Dioxide	11.57
Hydrogen Sulfide	0.00
Methane	0.00
Ethane	0.00
Propane	0.00
i-Butane	0.00
n-Butane	0.04
i-Pentane	0.00
n-Pentane	0.09
Hexanes	0.23
Heptanes Plus	88.07
Total	100.00

STOCK TANK OIL PROPERTIES: API Gravity at 60°F = 34.6
Density at 60°F = 0.8501 g/cc
Molecular Weight = 246

PROPERTIES OF HEPTANES PLUS: Molecular Weight = 247**

PROPERTIES OF WELL STREAM: Molecular Weight = 222.6
Bubble Point = 198 psia @ 165°F

**Calculated from stock tank mole weight and composition

TABLE 5

FLUID PROPERTIES: PORT NECHES FIELD
H. J. KUHN #33 WELL - 11.57 MOLE PERCENT CO_2
TEMPERATURE = 165°F

Pressure (psia)	Relative Volume[1]	Liquid Volume %[2]
100	1.7353	----
120	1.4772	66.4
140	1.2970	76.1
160	1.1652	84.9
180	1.0654	93.1
198*	1.0000	100.0
250	0.9997	100.0
500	0.9983	100.0
1000	0.9955	100.0
1500	0.9928	100.0
2000	0.9900	100.0
3000	0.9846	100.0
4000	0.9792	100.0

[1]Volume of fluid at pressure relative to the volume of fluid at saturation pressure.

[2]Volume of liquid at pressure relative to the total volume of fluid at that pressure.

*Bubble point pressure. Density at bubble point = 0.8148 g/cc
Swelling Index (volume of mixture at bubble point pressure/volume of stock tank oil at 15 psia and 165°F) = 1.019

TABLE 6

CALCULATED COMPOSITION OF 29.82 MOLE % CO_2 MIXTURE
PORT NECHES FIELD, H. J. KUHN #33 WELL

Component	Well Stream Mole %
Nitrogen	0.00
Carbon Dioxide	29.82
Hydrogen Sulfide	0.00
Methane	0.00
Ethane	0.00
Propane	0.00
i-Butane	0.00
n-Butane	0.03
i-Pentane	0.00
n-Pentane	0.07
Hexanes	0.18
Heptanes Plus	69.90
Total	100.00

STOCK TANK OIL PROPERTIES: API Gravity at 60°F = 34.6
Density at 60°F = 0.8501 g/cc
Molecular Weight = 246

PROPERTIES OF HEPTANES PLUS: Molecular Weight = 247**

PROPERTIES OF WELL STREAM: Molecular Weight = 185.8
Bubble Point = 580 psia @ 165°F

**Calculated from stock tank mole weight and composition

TABLE 7

FLUID PROPERTIES: PORT NECHES FIELD
H. J. KUHN #33 WELL - 29.82 MOLE PERCENT CO_2
TEMPERATURE = 165°F

Pressure (psia)	Relative Volume[1]	Liquid Volume %[2]
200	2.6722	35.4
250	2.1427	39.8
300	1.7923	55.8
350	1.5467	70.4
400	1.3667	77.2
450	1.2300	83.4
500	1.1233	89.2
580*	1.0000	100.0
750	0.9989	100.0
1000	0.9973	100.0
1500	0.9941	100.0
2000	0.9911	100.0
3000	0.9854	100.0
4000	0.9800	100.0
5000	0.9751	100.0

[1]Volume of fluid at pressure relative to the volume of fluid at saturation pressure.

[2]Volume of liquid at pressure relative to the total volume of fluid at that pressure.

*Bubble point pressure. Density at bubble point = 0.8203 g/cc Swelling Index (volume of mixture at bubble point pressure/volume of stock tank oil at 15 psia and 165°F) = 1.064

TABLE 8

CALCULATED COMPOSITION OF 49.61 MOLE % CO_2 MIXTURE
PORT NECHES FIELD, H. J. KUHN #33 WELL

Component	Well Stream Mole %
Nitrogen	0.00
Carbon Dioxide	49.61
Hydrogen Sulfide	0.00
Methane	0.00
Ethane	0.00
Propane	0.00
i-Butane	0.00
n-Butane	0.02
i-Pentane	0.00
n-Pentane	0.05
Hexanes	0.13
Heptanes Plus	50.19
Total	100.00

STOCK TANK OIL PROPERTIES: API Gravity at 60°F = 34.6
Density at 60°F = 0.8501 g/cc
Molecular Weight = 246

PROPERTIES OF HEPTANES PLUS: Molecular Weight = 247**

PROPERTIES OF WELL STREAM: Molecular Weight = 145.8
Bubble Point = 1150 psia @ 165°F

**Calculated from stock tank mole weight and composition

TABLE 9

FLUID PROPERTIES: PORT NECHES FIELD
H. J. KUHN #33 WELL - 49.61 MOLE PERCENT CO_2
TEMPERATURE = 165°F

Pressure (psia)	Relative Volume[1]	Liquid Volume %[2]
500	2.2070	42.4
600	1.8316	52.0
700	1.5681	61.3
800	1.3753	70.4
900	1.2302	79.1
1000	1.1190	87.6
1150*	1.0000	100.0
1500	0.9970	100.0
2000	0.9931	100.0
2500	0.9894	100.0
3000	0.9859	100.0
3500	0.9826	100.0
4000	0.9793	100.0
5000	0.9731	100.0

[1]Volume of fluid at pressure relative to the volume of fluid at saturation pressure.

[2]Volume of liquid at pressure relative to the total volume of fluid at that pressure.

*Bubble point pressure. Density at bubble point = 0.8257 g/cc
Swelling Index (volume of mixture at bubble point pressure/volume of stock tank oil at 15 psia and 165°F) = 1.156

TABLE 10

CALCULATED COMPOSITION OF 69.74 MOLE % CO_2 MIXTURE
PORT NECHES FIELD, H. J. KUHN #33 WELL

Component	Well Stream Mole %
Nitrogen	0.00
Carbon Dioxide	69.74
Hydrogen Sulfide	0.00
Methane	0.00
Ethane	0.00
Propane	0.00
i-Butane	0.00
n-Butane	0.01
i-Pentane	0.00
n-Pentane	0.03
Hexanes	0.08
Heptanes Plus	30.14
Total	100.00

STOCK TANK OIL PROPERTIES: API Gravity at 60°F = 34.6
Density at 60°F = 0.8501 g/cc
Molecular Weight = 246

PROPERTIES OF HEPTANES PLUS: Molecular Weight = 247**

PROPERTIES OF WELL STREAM: Molecular Weight = 105.1
Bubble Point = 2070 psia @ 165°F

**Calculated from stock tank mole weight and composition

TABLE 11

FLUID PROPERTIES: PORT NECHES FIELD
H. J. KUHN #33 WELL - 69.74 MOLE PERCENT CO_2
TEMPERATURE = 165°F

Pressure (psia)	Relative Volume[1]	Liquid Volume %[2]
800	2.4980	31.0
900	2.1860	36.8
1000	1.9393	42.6
1250	1.5101	57.4
1500	1.2486	71.8
1750	1.0922	85.3
2070*	1.0000	100.0
2500	0.9946	100.0
3000	0.9888	100.0
3500	0.9834	100.0
4000	0.9784	100.0
5000	0.9692	100.0
6000	0.9612	100.0

[1]Volume of fluid at pressure relative to the volume of fluid at saturation pressure.

[2]Volume of liquid at pressure relative to the total volume of fluid at that pressure.

*Bubble point pressure. Density at bubble point = 0.8285 g/cc
Swelling Index (volume of mixture at bubble point pressure/volume of stock tank oil at 15 psia and 165°F) = 1.383

TABLE 12

CALCULATED COMPOSITION OF 79.50 MOLE % CO_2 MIXTURE
PORT NECHES FIELD, H.J. KUHN #33 WELL

Component	Well Stream Mole %
Nitrogen	0.00
Carbon Dioxide	79.50
Hydrogen Sulfide	0.00
Methane	0.00
Ethane	0.00
Propane	0.00
i-Butane	0.00
n-Butane	0.01
i-Pentane	0.00
n-Pentane	0.02
Hexanes	0.05
Heptanes Plus	20.42
Total	100.00

STOCK TANK OIL PROPERTIES: API Gravity at 60°F = 34.5
Density at 60°F = 0.8501 g/cc
Molecular Weight = 246

PROPERTIES OF HEPTANES PLUS: Molecular Weight = 247**

PROPERTIES OF WELL STREAM: Molecular Weight = 85.4
Bubble Point = 3115 psia @ 165°F

**Calculated from stock tank mole weight and composition

TABLE 13

FLUID PROPERTIES: PORT NECHES FIELD
H. J. KUHN #33 WELL - 79.50 MOLE PERCENT CO_2
TEMPERATURE = 165°F

Pressure (psia)	Relative Volume[1]	Liquid Volume %[2]
1250	2.0116	35.7
1500	1.5874	46.6
1750	1.3325	58.7
2000	1.1774	70.1
2250	1.0847	78.8
2500	1.0330	84.5
2750	1.0089	88.9
3115*	1.0000	100.0
3500	0.9933	100.0
4000	0.9856	100.0
4500	0.9786	100.0
5000	0.9723	100.0
6000	0.9607	100.0
7000	0.9503	100.0

[1]Volume of fluid at pressure relative to the volume of fluid at saturation pressure.

[2]Volume of liquid at pressure relative to the total volume of fluid at that pressure.

*Bubble point pressure. Density at bubble point = 0.8285 g/cc
Swelling Index (volume of mixture at bubble point pressure/volume of stock tank oil at 15 psia and 165°F) = 1.650

TABLE 14

CALCULATED COMPOSITION OF 84.71 MOLE % CO_2 MIXTURE
PORT NECHES FIELD, H.J. KUHN #33 WELL

Component	Well Stream Mole %
Nitrogen	0.00
Carbon Dioxide	84.71
Hydrogen Sulfide	0.00
Methane	0.00
Ethane	0.00
Propane	0.00
i-Butane	0.00
n-Butane	0.01
i-Pentane	0.00
n-Pentane	0.02
Hexanes	0.04
Heptanes Plus	15.23
Total	100.00

STOCK TANK OIL PROPERTIES: API Gravity at 60°F = 34.6
Density at 60°F = 0.8501 g/cc
Molecular Weight = 246

PROPERTIES OF HEPTANES PLUS: Molecular Weight = 247**

PROPERTIES OF WELL STREAM: Molecular Weight = 74.9
Bubble Point = 3970 psia @ 165°F

**Calculated from stock tank mole weight and composition

TABLE 15

FLUID PROPERTIES: PORT NECHES FIELD
H. J. KUHN #33 WELL - 84.71 MOLE PERCENT CO_2
TEMPERATURE = 165°F

Pressure (psia)	Relative Volume[1]	Liquid Volume %[2]	Viscosity (cp)
1500	1.8710	33.5	----
1750	1.5013	44.5	----
2000	1.2881	54.3	----
2250	1.1647	61.9	----
2500	1.0942	67.1	----
3000	1.0334	72.9	----
3500	1.0139	80.0	----
3970*	1.0000	100.0	0.419
4500	0.9894	100.0	0.434
5000	0.9808	100.0	0.448
5500	0.9731	100.0	0.461
6000	0.9661	100.0	0.475
6500	0.9595	100.0	0.489
7000	0.9531	100.0	0.503

[1]Volume of fluid at pressure relative to the volume of fluid at saturation pressure.

[2]Volume of liquid at pressure relative to the total volume of fluid at that pressure.

*Bubble point pressure. Density at bubble point = 0.8406 g/cc.

Swelling Index (volume of mixture at bubble point pressure/volume of stock tank oil at 15 psia and 165°F) = 1.922

TABLE 16

CALCULATED COMPOSITION OF 91.16 MOLE % CO_2 MIXTURE
PORT NECHES FIELD, H. J. KUHN #33 WELL

Component	Well Stream Mole %
Nitrogen	0.00
Carbon Dioxide	91.16
Hydrogen Sulfide	0.00
Methane	0.00
Ethane	0.00
Propane	0.00
i-Butane	0.00
n-Butane	0.00
i-Pentane	0.00
n-Pentane	0.01
Hexanes	0.02
Heptanes Plus	8.80
Total	100.00

STOCK TANK OIL PROPERTIES: API Gravity at 60°F = 34.6
Density at 60°F = 0.8501 g/cc
Molecular Weight = 246

PROPERTIES OF HEPTANES PLUS: Molecular Weight = 247**

PROPERTIES OF WELL STREAM: Molecular Weight = 61.9
Dew point pressure = 5780 psia @ 165°F

**Calculated from stock tank mole weight and composition

TABLE 17

FLUID PROPERTIES: PORT NECHES FIELD
H. J. KUHN #33 WELL - 91.16 MOLE PERCENT CO_2
TEMPERATURE = 165°F

Pressure (psia)	Relative Volume[1]	Liquid Volume %[2]
500	9.5751	3.8
1000	4.1838	9.5
1500	2.3627	18.4
2000	1.5491	29.6
2500	1.1820	34.0
3000	1.1270	35.7
3500	1.0841	35.9
4000	1.0554	34.6
4500	1.0346	31.2
5000	1.0188	23.4
5500	1.0061	7.5
5780**	1.0000	0.0
6000	0.9956	0.0
6500	0.9868	0.0
7000	0.9788	0.0
7500	0.9718	0.0

[1]Volume of fluid at pressure relative to the volume of fluid at saturation pressure.

[2]Volume of liquid at pressure relative to the total volume of fluid at that pressure.

**Dew point pressure. Density at dew point = 0.8470 g/cc.

Swelling Index (volume of mixture at bubble point pressure/volume of stock tank oil at 15 psia and 165°F) = 2.726

TABLE 18

CALCULATED COMPOSITION OF 95.04 MOLE % CO_2 MIXTURE
PORT NECHES FIELD, H. J. KUHN #33 WELL

Component	Well Stream Mole %
Nitrogen	0.00
Carbon Dioxide	95.04
Hydrogen Sulfide	0.00
Methane	0.00
Ethane	0.00
Propane	0.00
i-Butane	0.00
n-Butane	0.00
i-Pentane	0.00
n-Pentane	0.00
Hexanes	0.01
Heptanes Plus	4.94
Total	100.00

STOCK TANK OIL PROPERTIES: API Gravity at 60°F = 34.6
Density at 60°F = 0.8501 g/cc
Molecular Weight = 246

PROPERTIES OF HEPTANES PLUS: Molecular Weight = 247**

PROPERTIES OF WELL STREAM: Molecular Weight = 54.0
Dew point pressure not determined

**Calculated from stock tank mole weight and composition

TABLE 19

FLUID PROPERTIES: PORT NECHES FIELD
H. J. KUHN #33 WELL - 95.04 MOLE PERCENT CO_2
TEMPERATURE = 165°F

Pressure (psia)	Relative Volume[1*]	Liquid Volume %[2]
500	48.9038	1.7
1000	21.1468	4.9
1500	11.7937	10.3
2000	7.3974	15.6
2500	5.8040	18.1
3000	5.1939	17.9
3500	4.8706	16.2
4000	4.6814	13.9
4500	4.5596	11.6
5000	4.4729	9.6
5500	4.4047	8.0
6000	4.3462	6.7
6500	4.2925	5.7
7000	4.2407	5.0
7500	4.1892	4.4
8000	4.1371	4.0

[1*]Volume of fluid at pressure relative to the volume of original stock tank fluid at 15 psia and 165°F.

[2]Volume of liquid at pressure relative to the total volume of fluid at that pressure.

[**]Dew point pressure greater than the pressure limitations of the windowed cell.

APPENDIX

PORT NECHES FIELD, H. J. KUHN #33 WELL, RAW DATA AT 165°F

Mole Fraction Live Oil/CO_2 = 1.000/0.000

Pressure (psia)	Sample Volume (cc)	Overall Density (g/cc)	Liquid Volume (%)
11	416.019	0.215	26.15
10	133.116	0.673	82.68
29	110.422	0.811	100.00
582	110.083	0.813	100.00
948	109.872	0.815	100.00
1328	109.665	0.817	100.00
1713	109.460	0.818	100.00
2106	109.259	0.820	100.00
2905	108.861	0.823	100.00
3717	108.468	0.826	100.00
4560	108.088	0.828	100.00

PORT NECHES FIELD, H. J. KUHN #33 WELL, RAW DATA AT 165°F

Mole Fraction Live Oil/CO_2 = 0.8843/0.1157

Pressure (psia)	Sample Volume (cc)	Overall Density (g/cc)	Liquid Volume (%)
147	140.175	0.654	79.19
152	136.476	0.672	81.54
166	127.412	0.719	87.16
177	121.372	0.755	92.21
187	116.342	0.788	95.64
194	113.325	0.809	98.93
257	112.424	0.815	
194	113.325	0.809	99.10
195	113.125	0.810	99.36
196	112.924	0.812	99.48
196	112.722	0.813	99.72
196	112.521	0.814	99.93
231	112.480	0.815	100.00
295	112.463	0.815	100.00
626	112.231	0.817	100.00
957	111.992	0.818	100.00
1304	111.758	0.820	100.00
1655	111.526	0.822	100.00
2378	111.074	0.825	100.00
3124	110.634	0.828	100.00
4685	109.787	0.835	100.00

PORT NECHES FIELD, H. J. KUHN #33 WELL, RAW DATA AT 165°F

Mole Fraction Live Oil/CO_2 = 0.7018/0.2982

Pressure (psia)	Sample Volume (cc)	Overall Density (g/cc)	Liquid Volume (%)
183	342.392	0.281	32.35
216	291.280	0.331	39.83
259	242.884	0.397	48.12
329	192.462	0.501	58.70
425	152.151	0.633	76.30
523	126.989	0.759	92.56
550	121.962	0.790	96.24
573	117.942	0.817	99.48
575	117.641	0.819	99.82
589	117.450	0.820	100.00
722	117.355	0.821	100.00
850	117.255	0.822	100.00
1241	116.957	0.824	100.00
1575	116.711	0.826	100.00
2265	116.234	0.829	100.00
2973	115.764	0.832	100.00
4445	114.851	0.839	100.00

PORT NECHES FIELD, H. J. KUHN #33 WELL, RAW DATA AT 165°F

Mole Fraction Live Oil/CO_2 = 0.5039/0.4961

Pressure (psia)	Sample Volume (cc)	Overall Density (g/cc)	Liquid Volume (%)
409	346.055	0.304	32.95
475	296.958	0.355	40.81
569	246.543	0.427	48.64
714	196.169	0.537	62.50
976	145.689	0.723	85.77
1089	132.854	0.793	95.15
1130	128.801	0.818	98.40
1522	127.131	0.828	
1143	127.847	0.824	99.62
1144	127.747	0.824	99.72
1148	127.649	0.825	99.87
1151	127.551	0.826	100.00
1264	127.436	0.826	100.00
1371	127.317	0.827	100.00
1485	127.203	0.828	100.00
1826	126.861	0.830	100.00
2111	126.575	0.832	100.00
2703	126.016	0.836	100.00
3325	125.479	0.839	100.00
4620	124.424	0.846	100.00

PORT NECHES FIELD, H. J. KUHN #33 WELL, RAW DATA AT 165°F

Mole Fraction Live Oil/CO_2 = 0.3026/0.6974

Pressure (psia)	Sample Volume (cc)	Overall Density (g/cc)	Liquid Volume (%)
884	340.755	0.371	35.52
1012	291.704	0.434	44.17
1199	241.355	0.524	53.64
1499	190.894	0.663	72.16
1789	164.057	0.771	86.89
1954	155.906	0.811	95.41
2045	153.148	0.826	99.10
2061	152.757	0.828	99.82
2101	152.585	0.829	100.00
2177	152.440	0.830	100.00
2252	152.295	0.830	100.00
2442	151.933	0.832	100.00
2636	151.574	0.834	100.00
3464	150.179	0.842	100.00
4361	148.821	0.850	100.00
5337	147.520	0.857	100.00

PORT NECHES FIELD, H. J. KUHN #33 WELL, RAW DATA AT 165°F

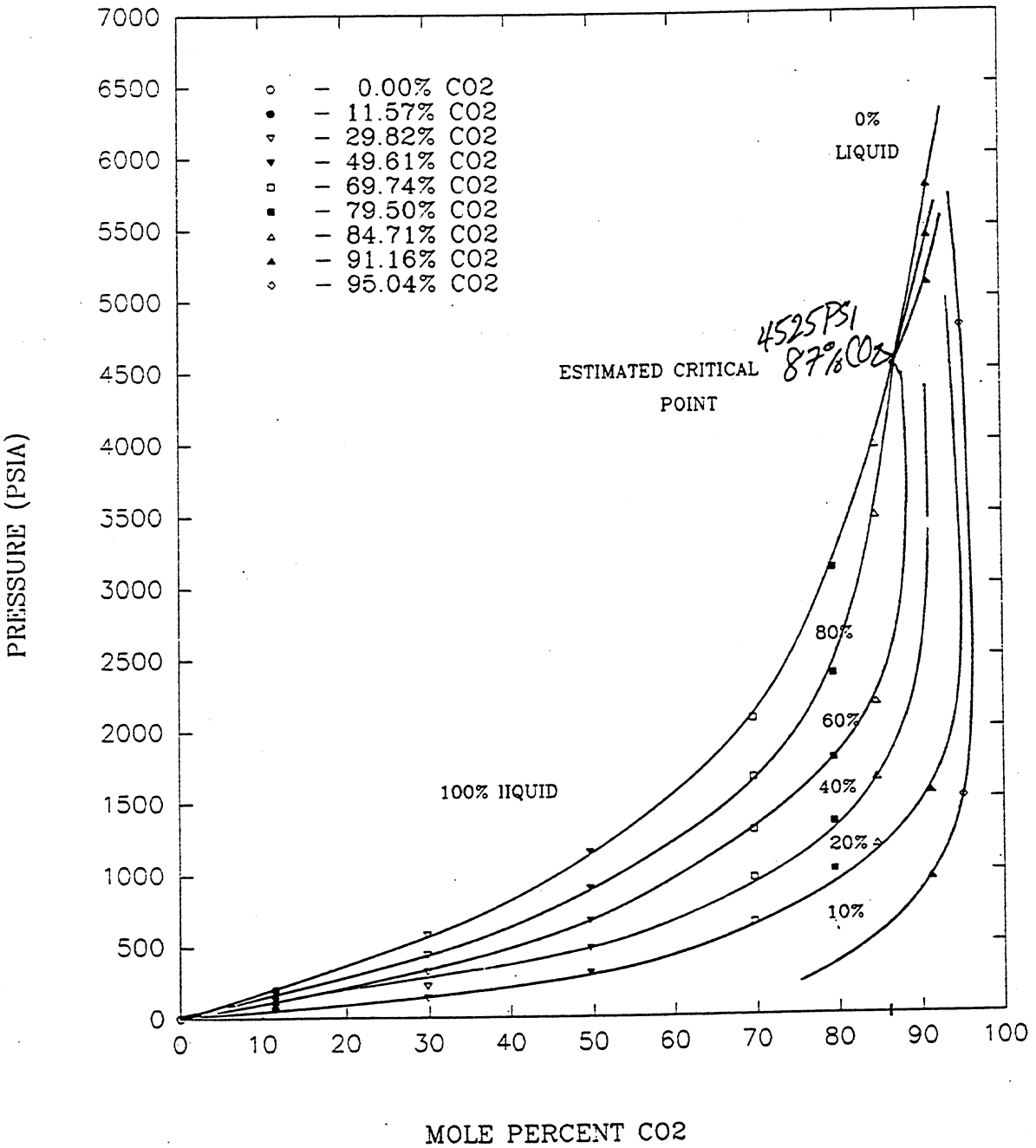
Mole Fraction Live Oil/CO_2 = 0.2050/0.7950

Pressure (psia)	Sample Volume (cc)	Overall Density (g/cc)	Liquid Volume (%)
1268	358.474	0.423	36.28
1425	309.440	0.490	43.72
1659	257.105	0.590	53.55
2039	208.925	0.726	72.23
2531	189.099	0.802	84.72
3813	181.972	0.834	
3310	181.401	0.836	
2952	183.355	0.827	94.04
2997	182.985	0.829	95.65
3044	182.616	0.831	97.02
3089	182.246	0.832	98.93
3115	182.063	0.833	100.00
3212	181.732	0.835	100.00
3317	181.406	0.836	100.00
3422	181.080	0.838	100.00
3529	180.756	0.839	100.00
3812	179.953	0.843	100.00
4414	178.372	0.850	100.00
5077	176.836	0.858	100.00

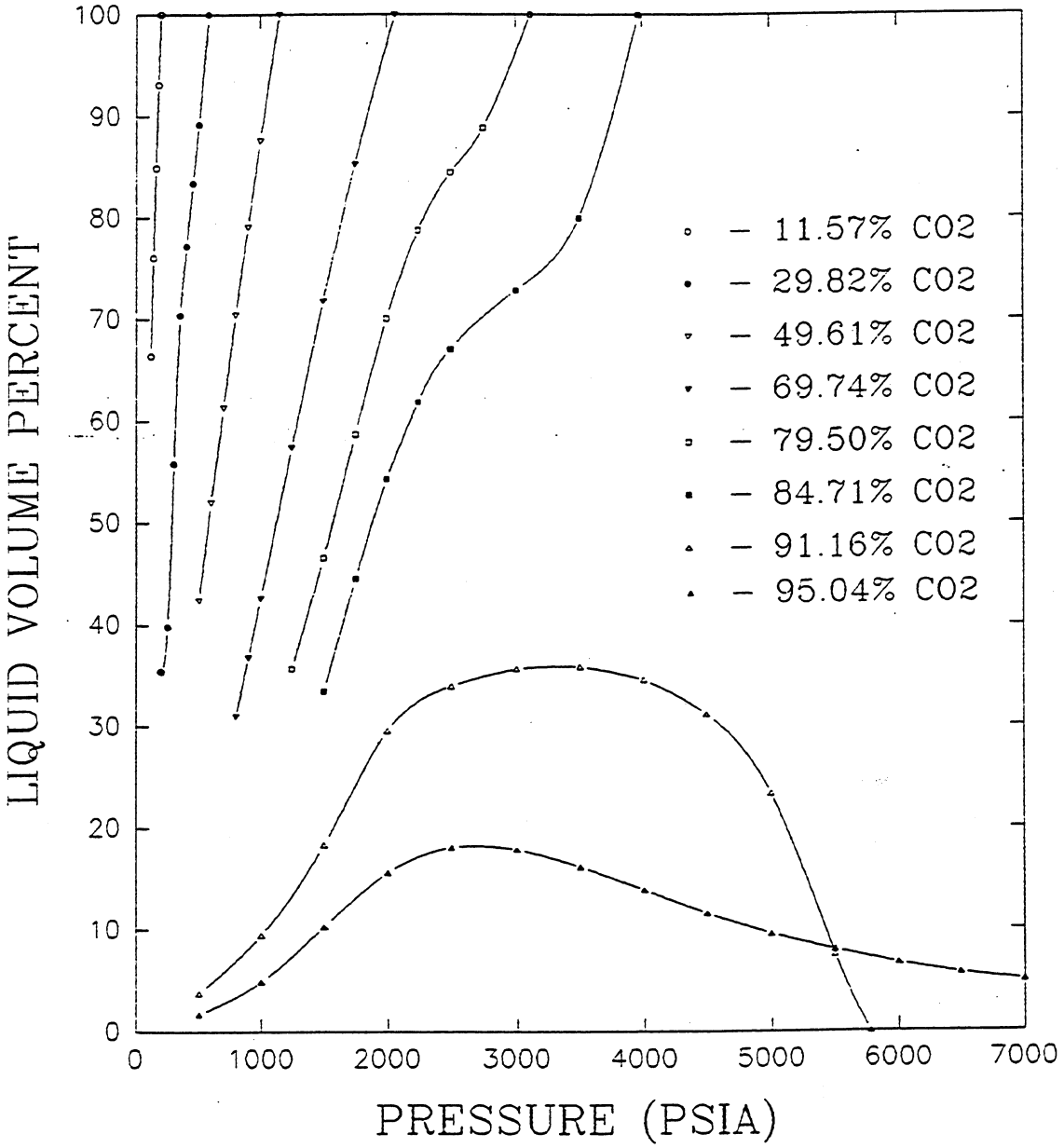
PORT NECHES FIELD, H. J. KUHN #33 WELL

PRESSURE-COMPOSITION DIAGRAM

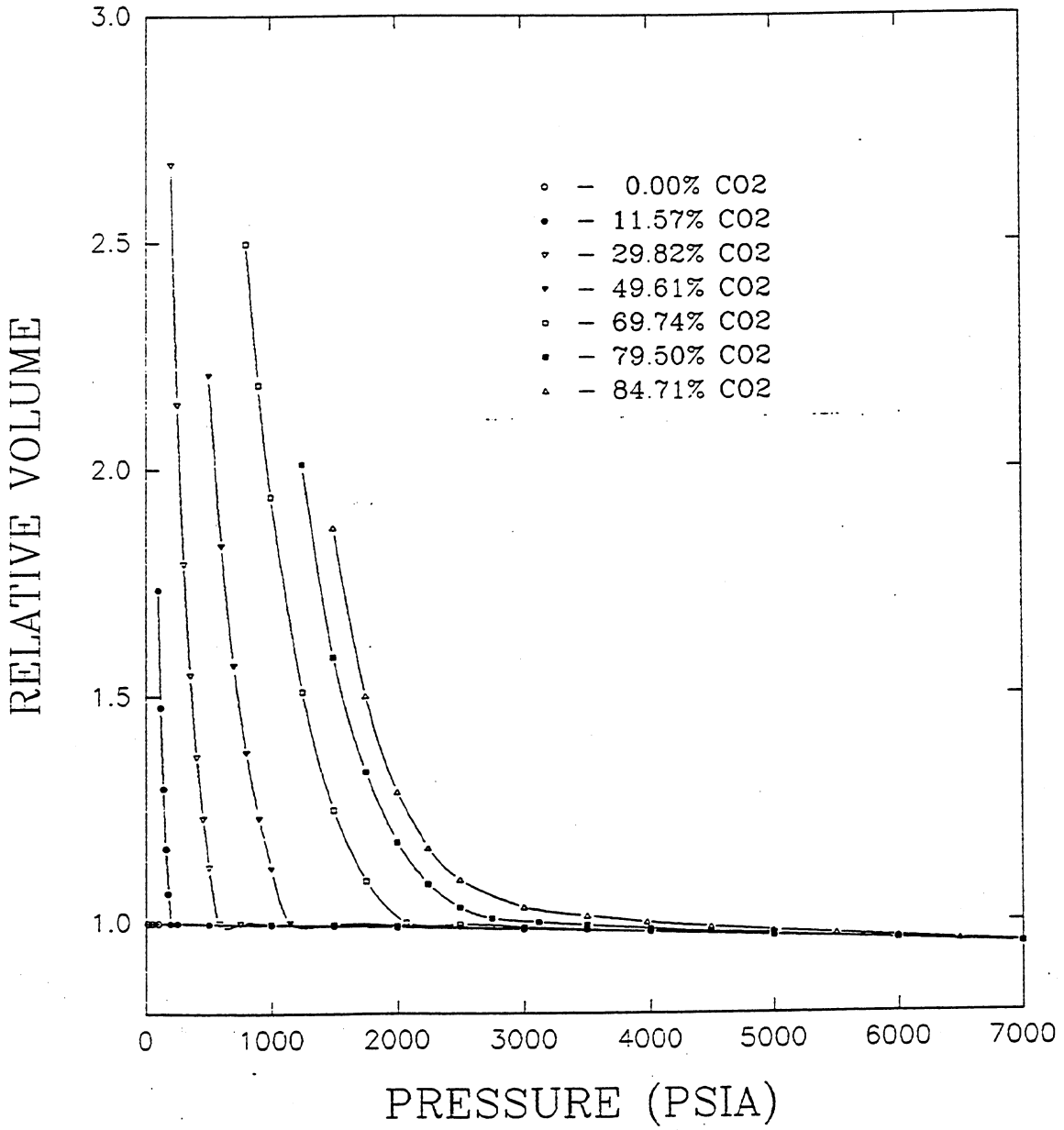
STOCK TANK OIL - CO2 AT 165 F



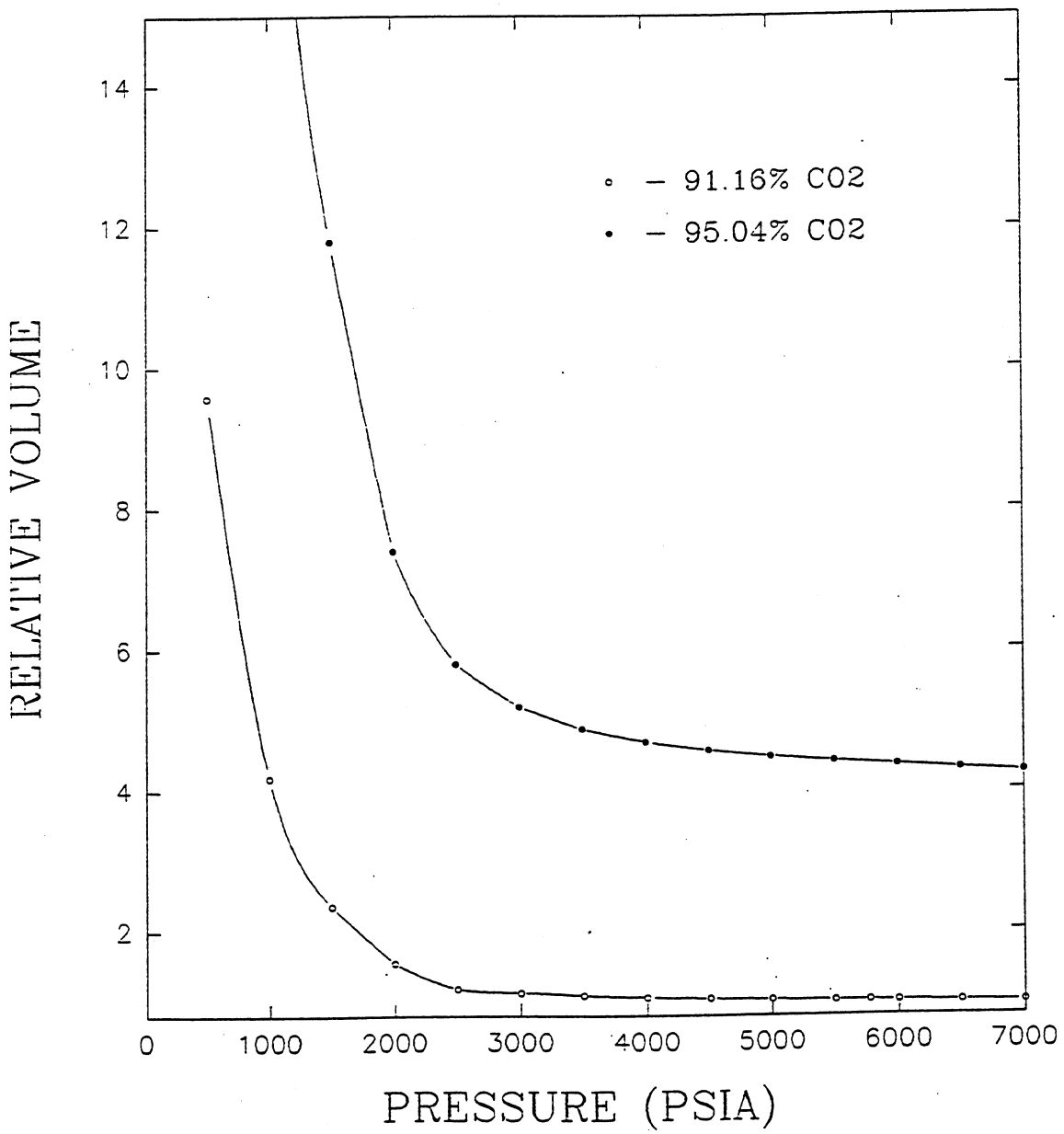
PORT NECHES FIELD
LIQUID VOLUME VS PRESSURE
STOCK TANK OIL –CO2 AT 165 F



PORT NECHES FIELD
RELATIVE VOLUME VS PRESSURE
STOCK TANK OIL – CO2 AT 165 F



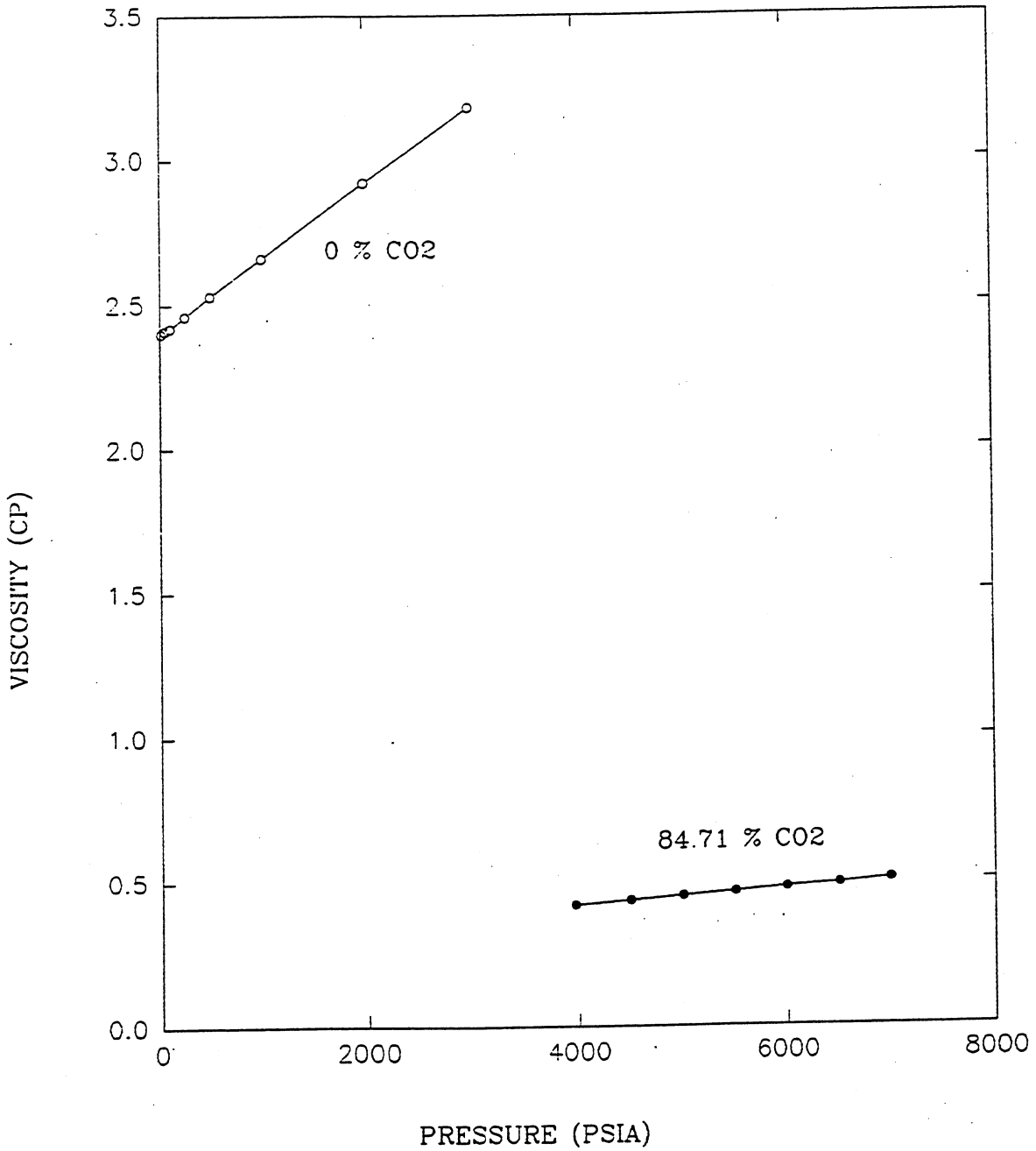
PORT NECHES FIELD
RELATIVE VOLUME VS PRESSURE
STOCK TANK OIL – CO2 AT 165 F



PORT NECHES FIELD VISCOSITY STUDY

STROCK TANK OIL – CO2

VISCOSITY VS PRESSURE



PHASE 2 - CO_2 SWELLING/SOLUBILITY STUDIES FOR RESERVOIR FLUIDS OF THE PORT NECHES FIELD, H.J. KUHN #33 WELL ORANGE COUNTY, TEXAS

PHASE 2 - CO_2 SWELLING/SOLUBILITY STUDIES FOR RESERVOIR FLUIDS OF THE PORT NECHES FIELD, H. J. KUHN #33 WELL ORANGE COUNTY, TEXAS

PREPARED BY: _____
M. W. WIDENER

_____
T. M. VU

REPORT NO. 91-XXX

PROJECT 502-90-1395 CONFIDENTIAL 1991

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EXECUTIVE SUMMARY

A carbon dioxide flood has been proposed for the Port Neches Field, Orange County, Texas. At the request of the CO_2 Group, Harvey, Louisiana swelling/solubility and viscosity reduction experiments were conducted. A synthetic gas was recombined with stock tank oil from the H. J. Kuhn #33 Well to approximate the original reservoir fluid. This reservoir fluid and CO_2 at reservoir conditions were used in this second phase of the study.

These tests are run to determine the physical properties of various mixtures of reservoir fluid and CO_2. These properties are necessary to define the CO_2-hydrocarbon interaction coefficients used in compositional reservoir simulation. The tests showed:

Significant hydrocarbon liquid phase swelling

Significant viscosity reduction

Minimal increase in density

INTRODUCTION

This work is in support of the proposed CO_2 EOR project in the Port Neches Field, Orange County, Texas. The purpose of this study is to determine the change in physical properties that will result from the addition of CO_2 to Port Neches Field reservoir fluid. These tests are run at reservoir temperature and pressures. Experimental determination of these values is necessary to define the CO_2-hydrocarbon interaction coefficients used in compositional reservoir simulation and for history matching.

Little information is available on the properties of the original fluids from the Port Neches Field. The reservoir fluid used in this portion of the study was the produced stock tank oil from the H. J. Kuhn #33 Well recombined with synthetic gas to represent the original reservoir fluid. The original fluid is believed to have a GOR of approximately 500 scf/stb and a bubble point of 2700 psia (the original reservoir pressure). Compositions of separator gas samples from this area, the stock tank oil composition, the GOR, and K-values were used to approximate a wellstream composition. This recombined fluid had a bubble point pressure of 2685 psia at 165°F which is very close to the original reservoir pressure.

The current reservoir temperature is approximately 165°F. The current reservoir pressure is approximately 1865 psia.

CONCLUSIONS

Concentrations of 0 to 69.96 mole % CO_2 were bubble point fluids. These mixtures resulted in a:

70.0 % increase in saturation pressure volume.

47.1 % decrease in saturation pressure viscosity.

6.2 % increase in saturation pressure density.

Concentrations of 80, 90, and 95 mole % CO_2 were dew point fluids. The actual dew point pressures and physical properties for these fluids are not reported since the experimental results appear to be questionable. A sample of this reservoir fluid will be retained if the data reported in this study combined with the data reported in Phase 1 is insufficient for equation of state tuning.

FUTURE WORK

This completes the second and final phase of the CO_2 phase behavior study of the Port Neches Field, H. J. Kuhn #33 Well, Orange County, Texas EOR Study.

DISCUSSION

The Port Neches Field is under consideration for CO_2 EOR. Oil samples were collected from the H. J. Kuhn #33 Well. Little information is available on the properties of the original fluids from the Port Neches Field. The current producing gas-oil ratio is approximately 11 scf/stb and the reservoir has been depleted to approximately 50 psi. The current reservoir temperature is 165°F. The current reservoir pressure under waterflood is approximately 1865 psia.

The reservoir fluid used in this portion of the study was a synthetic reservoir fluid. It is believed that the original reservoir fluid had a GOR of 500 scf/stb and a bubble point pressure near the original reservoir pressure of approximately 2700 psia.

Oil samples were collected from the H. J. Kuhn #33 Well. A separator gas sample from a similar field in this area was used along with the separator pressure and temperature, a 500 scf/stb GOR, the stock tank oil composition, and K-values to estimate the wellstream composition. The experimentally determined bubble point for this reservoir fluid was 2685 psia at 165°F. This fluid was used for the study since its bubble point pressure was so close to the reported original pressure.

The hydrocarbon analysis and properties for the reservoir fluid used in the current study are given in Table 1. All EPTD compositions reported are based on chromatographic analysis. The formation volume factor reported in table 3 is based on 88.68 weight % of the original synthesized live oil being produced as stock tank oil.

Swelling/Solubility Measurements

Swelling/solubility measurements were made on 5 separate mixtures of live oil and CO_2 at the reservoir temperature of 165°F. The composition was varied from 0 to 69.96 mole % CO_2. Bubble point systems included 0, 20.28, 39.87, 60.42, and 69.96 mole % CO_2 mixtures. Concentrations of 80, 90, and 95 mole % CO_2 resulted in dew point fluids. The physical properties of these three mixtures have not been reported or used since the results were questionable.

The results are given in Tables 2 - 11 and in Figs. 1 - 4. The data in Tables 3, 5, 7, 9, and 11 were smoothed and interpolated to give values at even pressure increments. The raw laboratory data are included in an appendix.

Critical Point

A liquid-vapor critical point has not been estimated for this live oil/CO2 system because the dew point fluids are not being considered.

Graphical Presentation

Figure 1 shows the conditions of pressure and composition which result in a given volume fraction of hydrocarbon liquid. The liquid-vapor critical point has been estimated. The iso-vol lines represent the liquid phase volume %, the balance being vapor.

Figure 2 show the pressure necessary to achieve a given liquid volume % for each of the mixtures. Cross plotting these individual mixtures enables one to develop the phase envelope presented in Figure 1.

Figure 3 show relative volumes (V_P/V_{SAT}) as a function of pressure for the mixtures.

Figure 4 shows the results of the viscosity reduction tests.

TABLE 1

HYDROCARBON ANALYSIS OF RESERVOIR FLUID USED IN CURRENT PVT STUDY
EXTENDED ANALYSIS - PORT NECHES FIELD, H. J. KUHN #33 WELL

Component	Well Stream Mole %
Nitrogen	0.54
Carbon Dioxide	0.47
Hydrogen Sulfide	0.00
Methane	41.30
Ethane	3.75
Propane	2.50
i-Butane	0.00
n-Butane	2.54
i-Pentane	0.03
n-Pentane	1.59
Hexanes	0.93
Heptanes	0.81
Octanes	1.23
Nonanes	2.33
Decanes	2.89
Undecanes	3.06
Dodecanes	3.20
Tridecanes	3.73
Tetradecanes	3.64
Pentadecanes	3.11
Hexadecanes Plus	22.35
Total	100.00

Composition based on GC analysis with capillary column. Katz and Firoozabadi molecular weights (JPT, November, 1978) used to calculate component mole percent.

Mole weight stock tank oil = 246
API gravity stock tank oil @ 60°F/60°F = 34.6
Density of stock tank oil @ 60°F = 0.8501 g/cc

Calculated mole weight of wellstream = 127
Calculated mole weight heptane plus fraction = 247
Calculated mole weight hexadecane plus fraction = 340

TABLE 2

PORT NECHES FIELD, H. J. KUHN #33
LIVE OIL SWELLING SOLUBILITY TEST SUMMARY
Properties at Saturation Pressure and 165°F

Mole % CO_2	Saturation Pressure (psia)	Swelling Index	Density (g/cc)	Viscosity (cp)
0.0	2685*	1.0000	0.7328	0.97 — live oil original / Stock Tank oil 2.4
20.28	3002*	1.0701	0.7452	----
39.87	3344*	1.1783	0.7648	0.661
60.42	4083*	1.4480	0.7739	----
69.96	4456*	1.7005	0.7786	0.513

*Bubble point pressures.

**Dew point pressure. Several concentrations above 69.96 mole % CO2 were examined. The results are questionable and are not reported.

TABLE 3

FLUID PROPERTIES: PORT NECHES FIELD
H. J. KUHN #33 WELL - STOCK TANK OIL
TEMPERATURE = 165°F

Pressure (psia)	Relative Volume[1]	Liquid Volume %[2]	Viscosity (cp)
400	3.3542	25.26	----
800	1.8778	46.95	----
1200	1.4228	63.67	----
1600	1.2139	76.50	----
2000	1.1002	86.47	----
2400	1.0322	94.66	----
2685*	1.0000	100.0	0.97
3000	0.9973	100.0	1.00
3500	0.9932	100.0	1.04
4000	0.9894	100.0	1.08
4500	0.9859	100.0	1.12
5000	0.9825	100.0	1.16
5500	0.9793	100.0	1.21

[1]Volume of fluid at pressure relative to the volume of fluid at saturation pressure.

[2]Volume of liquid at pressure relative to the total volume of fluid at that pressure.

*Bubble point pressure. Density at bubble point = 0.7328 g/cc. Formation volume factor at bubble point pressure = 1.308 reservoir bbls/stock tank bbl (assuming 88.68 wt % reservoir fluid being produced as stock tank oil).

TABLE 4

CALCULATED COMPOSITION OF 20.28 MOLE % CO_2 MIXTURE
PORT NECHES FIELD, LIVE OIL, H. J. KUHN #33 WELL

Component	Well Stream Mole %
Nitrogen	0.43
Carbon Dioxide	20.66
Hydrogen Sulfide	0.00
Methane	32.92
Ethane	2.99
Propane	1.99
i-Butane	0.00
n-Butane	2.02
i-Pentane	0.02
n-Pentane	1.27
Hexanes	0.74
Heptanes Plus	36.96
Total	100.00

STOCK TANK OIL PROPERTIES: API Gravity at 60°F = 34.6
Density at 60°F = 0.8501 g/cc
Molecular Weight = 246

PROPERTIES OF HEPTANES PLUS: Molecular Weight = 247**

PROPERTIES OF WELL STREAM: Molecular Weight = 110.2
Bubble Point = 3002 psia @ 165°F

**Calculated from stock tank mole weight and composition

TABLE 5

FLUID PROPERTIES: PORT NECHES FIELD, LIVE OIL
H. J. KUHN #33 WELL - 20.28 MOLE PERCENT CO_2
TEMPERATURE = 165°F

Pressure (psia)	Relative Volume[1]	Liquid Volume %[2]
600	2.8583	28.62
1000	1.8412	46.69
1250	1.5564	56.26
1500	1.3772	64.69
1750	1.2568	72.13
2000	1.1721	78.74
2250	1.1103	84.68
2500	1.0639	90.09
2750	1.0282	95.13
3002*	1.0000	100.00
3500	0.9951	100.00
4000	0.9905	100.00
4500	0.9862	100.00
5000	0.9822	100.00
5500	0.9783	100.00
6000	0.9746	100.00

[1]Volume of fluid at pressure relative to the volume of fluid at saturation pressure.

[2]Volume of liquid at pressure relative to the total volume of fluid at that pressure.

*Bubble point pressure. Density at bubble point = 0.7452 g/cc
Swelling Index (volume of mixture at bubble point pressure/volume of original reservoir fluid at 2685 psia and 165°F) = 1.0701

TABLE 6

CALCULATED COMPOSITION OF 39.87 MOLE % CO_2 MIXTURE
PORT NECHES FIELD, LIVE OIL, H. J. KUHN #33 WELL

Component	Well Stream Mole %
Nitrogen	0.32
Carbon Dioxide	40.16
Hydrogen Sulfide	0.00
Methane	24.83
Ethane	2.25
Propane	1.50
i-Butane	0.00
n-Butane	1.53
i-Pentane	0.02
n-Pentane	0.96
Hexanes	0.56
Heptanes Plus	27.87
Total	100.00

STOCK TANK OIL PROPERTIES: API Gravity at 60°F = 34.6
Density at 60°F = 0.8501 g/cc
Molecular Weight = 246

PROPERTIES OF HEPTANES PLUS: Molecular Weight = 247**

PROPERTIES OF WELL STREAM: Molecular Weight = 93.9
Bubble Point = 3344 psia @ 165°F

**Calculated from stock tank mole weight and composition

TABLE 7

FLUID PROPERTIES: PORT NECHES FIELD, LIVE OIL
H. J. KUHN #33 WELL - 39.87 MOLE PERCENT CO_2
TEMPERATURE = 165°F

Pressure (psia)	Relative Volume[1]	Liquid Volume %[2]	Viscosity (cp)
800	2.6741	28.82	----
1000	2.1636	36.86	----
1500	1.5259	53.99	----
2000	1.2486	68.42	----
2500	1.1097	81.14	----
3000	1.0338	92.64	----
3344*	1.0000	100.00	0.661
4000	0.9916	100.00	0.680
4500	0.9862	100.00	0.696
5000	0.9814	100.00	0.715
5500	0.9771	100.00	0.735
6000	0.9732	100.00	0.757

[1]Volume of fluid at pressure relative to the volume of fluid at saturation pressure.

[2]Volume of liquid at pressure relative to the total volume of fluid at that pressure.

*Bubble point pressure. Density at bubble point = 0.7648 g/cc
Swelling Index (volume of mixture at bubble point pressure/volume of original reservoir fluid at 2685 psia and 165°F) = 1.1783

TABLE 8

CALCULATED COMPOSITION OF 60.42 MOLE % CO_2 MIXTURE
PORT NECHES FIELD, LIVE OIL, H. J. KUHN #33 WELL

Component	Well Stream Mole %
Nitrogen	0.21
Carbon Dioxide	60.61
Hydrogen Sulfide	0.00
Methane	16.35
Ethane	1.48
Propane	0.99
i-Butane	0.00
n-Butane	1.01
i-Pentane	0.01
n-Pentane	0.63
Hexanes	0.37
Heptanes Plus	18.34
Total	100.00

STOCK TANK OIL PROPERTIES: API Gravity at 60°F = 34.6
Density at 60°F = 0.8501 g/cc
Molecular Weight = 246

PROPERTIES OF HEPTANES PLUS: Molecular Weight = 247**

PROPERTIES OF WELL STREAM: Molecular Weight = 76.8
Bubble Point = 4083 psia @ 165°F

**Calculated from stock tank mole weight and composition

TABLE 9

FLUID PROPERTIES: PORT NECHES FIELD, LIVE OIL
H. J. KUHN #33 WELL - 60.42 MOLE PERCENT CO_2
TEMPERATURE = 165°F

Pressure (psia)	Relative Volume[1]	Liquid Volume %[2]
1300	2.1515	31.17
1500	1.8486	37.18
2000	1.4106	51.90
2500	1.2001	64.43
3000	1.0931	74.53
3500	1.0367	84.15
4083*	1.0000	100.00
4500	0.9926	100.00
5000	0.9846	100.00
5500	0.9774	100.00
6000	0.9709	100.00
6500	0.9650	100.00
7000	0.9595	100.00

[1]Volume of fluid at pressure relative to the volume of fluid at saturation pressure.

[2]Volume of liquid at pressure relative to the total volume of fluid at that pressure.

*Bubble point pressure. Density at bubble point = 0.7739 g/cc
Swelling Index (volume of mixture at bubble point pressure/volume of original reservoir fluid at 2685 psia and 165°F) = 1.4480

TABLE 10

CALCULATED COMPOSITION OF 69.96 MOLE % CO_2 MIXTURE
PORT NECHES FIELD, LIVE OIL, KUHN #33 WELL

Component	Well Stream Mole %
Nitrogen	0.16
Carbon Dioxide	70.10
Hydrogen Sulfide	0.00
Methane	12.41
Ethane	1.13
Propane	0.75
i-Butane	0.00
n-Butane	0.76
i-Pentane	0.01
n-Pentane	0.48
Hexanes	0.28
Heptanes Plus	13.92
Total	100.00

STOCK TANK OIL PROPERTIES: API Gravity at 60°F = 34.6
Density at 60°F = 0.8501 g/cc
Molecular Weight = 246

PROPERTIES OF HEPTANES PLUS: Molecular Weight = 247**

PROPERTIES OF WELL STREAM: Molecular Weight = 68.9
Bubble Point = 4456 psia @ 165°F

**Calculated from stock tank mole weight and composition

TABLE 11

FLUID PROPERTIES: PORT NECHES FIELD, LIVE OIL
H. J. KUHN #33 WELL - 69.96 MOLE PERCENT CO_2
TEMPERATURE = 165°F

Pressure (psia)	Relative Volume[1]	Liquid Volume %[2]	Viscosity (cp)
1600	1.9137	31.23	----
2000	1.4974	41.59	----
2500	1.2409	52.01	----
3000	1.1181	61.07	----
3500	1.0561	69.53	----
4000	1.0217	78.52	----
4456*	1.0000	100.00	0.513
4750	0.9935	100.00	0.518
5000	0.9883	100.00	0.522
5500	0.9789	100.00	0.532
6000	0.9704	100.00	0.542
6500	0.9628	100.00	0.555
7000	0.9558	100.00	0.569

[1]Volume of fluid at pressure relative to the volume of fluid at saturation pressure.

[2]Volume of liquid at pressure relative to the total volume of fluid at that pressure.

*Bubble point pressure. Density at bubble point = 0.7786 g/cc
Swelling Index (volume of mixture at bubble point pressure/volume of original reservoir fluid at 2685 psia and 165°F) = 1.7005

APPENDIX

PORT NECHES FIELD, LIVE OIL,
H. J. KUHN #33 WELL, RAW DATA AT 165°F

Mole Fraction Live Oil/CO_2 = 1.000/0.000

Pressure (psia)	Sample Volume (cc)	Overall Density (g/cc)	Liquid Volume (%)
353	416.431	0.1949	22.57
406	366.281	0.2215	25.41
380	315.761	0.2570	29.91
588	265.466	0.3057	36.46
766	215.124	0.3772	44.91
1116	164.925	0.4920	60.86
1383	144.938	0.5599	69.89
1868	125.122	0.6485	83.27
2325	115.376	0.7033	93.65
2754	110.655	0.7333	
2469	113.467	0.7151	95.61
2608	111.554	0.7274	98.38
2650	111.081	0.7305	99.38
2669	110.893	0.7317	99.69
2707	110.720	0.7329	
2697	110.813	0.7323	
3576	109.932	0.7381	
4160	109.436	0.7415	
4678	109.024	0.7443	
2898	110.508	0.7343	

Mole Fraction Live Oil/CO_2 = 0.7972/0.2028

Pressure (psia)	Sample Volume (cc)	Overall Density (g/cc)	Liquid Volume (%)
576	351.828	0.2510	27.46
682	301.726	0.2927	32.60
840	251.379	0.3513	40.13
1107	201.121	0.4390	50.47
1685	151.094	0.5844	70.47
2227	131.323	0.6724	84.51
2750	121.626	0.7260	95.10
3926	117.466	0.7517	
2905	119.725	0.7375	97.69
3383	118.068	0.7479	
2986	118.777	0.7434	99.33
3102	118.360	0.7460	
3724	117.660	0.7505	
4195	117.171	0.7536	
4672	116.691	0.7567	
5283	116.109	0.7605	
5801	115.665	0.7634	

PORT NECHES FIELD, LIVE OIL,
H. J. KUHN #33 WELL, RAW DATA AT 165°F

Mole Fraction Live Oil/CO_2 = 0.6013/03987

Pressure (psia)	Sample Volume (cc)	Overall Density (g/cc)	Liquid Volume (%)
799	349.392	0.2856	28.56
942	298.311	0.3345	34.50
1154	247.997	0.4024	42.78
1513	197.794	0.5045	54.44
2382	147.986	0.6743	78.77
2800	138.208	0.7220	87.80
2978	135.314	0.7375	62.28
3334	130.537	0.7644	99.69
3522	130.173	0.7666	
3432	130.308	0.7658	
4135	129.149	0.7727	
4664	128.431	0.7770	
5120	127.996	0.7796	
5576	127.355	0.7835	

Mole Fraction Live Oil/CO_2 = 0.3958/0.6042

Pressure (psia)	Sample Volume (cc)	Overall Density (g/cc)	Liquid Volume (%)
1306	343.046	0.3617	31.29
1519	293.013	0.4235	37.99
1841	242.776	0.5111	47.09
2489	192.785	0.6436	64.19
3096	171.030	0.7255	76.46
3192	172.110	0.7209	78.35
3302	169.165	0.7335	80.39
3657	164.382	0.7548	87.26
3829	162.491	0.7636	91.42
4047	160.633	0.7724	98.47
4268	159.787	0.7765	
4086	160.158	0.7747	
4623	158.818	0.7813	
5153	157.499	0.7878	
5609	156.472	0.7930	
6123	155.429	0.7983	
6704	154.360	0.8038	

PORT NECHES FIELD, LIVE OIL,
H. J. KUHN #33 WELL, RAW DATA AT 165°F

Mole Fraction Live Oil/CO_2 = 0.3007/0.6996

Pressure (psia)	Sample Volume (cc)	Overall Density (g/cc)	Liquid Volume (%)
1641	349.457	0.4196	32.29
1888	299.449	0.4896	39.19
2289	249.264	0.5882	47.70
3471	199.660	0.7344	69.08
4247	190.135	0.7712	84.54
4461	188.273	0.7788	
4292	189.663	0.7731	86.70
4343	189.196	0.7750	89.19
4401	188.734	0.7769	93.13
4427	188.551	0.7776	95.57
4461	188.273	0.7788	
4867	186.546	0.7860	
5327	184.825	0.7933	
5844	183.171	0.8005	
6358	181.680	0.8070	
6837	180.417	0.8127	

DISTRIBUTION

PHASE 2 - CO_2 SWELLING/SOLUBILITY STUDIES FOR
RESERVOIR FLUIDS OF THE PORT NECHES FIELD,
H. J. KUHN #33 WELL
ORANGE COUNTY, TEXAS

Technical Report No. 91-xxx

MINIMUM MISCIBILITY PRESSURE OF CARBON DIOXIDE AND STOCK TANK OIL FROM WELL No. 33, PORT NECHES FIELD, TEXAS

MINIMUM MISCIBILITY PRESSURE OF CARBON DIOXIDE AND STOCK TANK OIL FROM WELL No. 33, PORT NECHES FIELD, TEXAS

REPORT NO. 91-060

The Texas Company

1941

1991

E&P TECHNOLOGY DEPARTMENT

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MINIMUM MISCIBILITY PRESSURE OF CARBON DIOXIDE AND STOCK TANK OIL FROM WELL No. 33, PORT NECHES FIELD, TEXAS

PREPARED BY: Jack Benard
J. H. Benard

J. C. Hsu
J. C. Hsu

REPORT NO. 91-060

PROJECT 4502-90-1359 CONFIDENTIAL APRIL 1991

EXECUTIVE SUMMARY

At the request of Onshore Producing - Eastern Region, a fluid sample from well No. 33, of the Port Neches Field, Texas was sent to EPTD for minimum miscibility pressure (MMP) determination. Tests were performed at 165°F with the EPTD automated high pressure slimtube apparatus. An MMP of 3310 psia was determined as a result of seven carbon dioxide slimtube displacements using Port Neches stock tank oil.

INTRODUCTION

As requested by Mr. T. R. Kaetzer, the minimum miscibility pressure (MMP) was determined at EPTD for oil from the Port Neches Field.

The stock tank oil was obtained from well No. 33 of the Port Neches Field, Texas in December, 1990. The MMP result was given verbally in early January. A stock tank oil was used for the MMP experiments because the reservoir pressure is below the bubble point and the gas composition of the oil is not known. The carbon dioxide slimtube displacements for determining the MMP were conducted at 165°F and various pressures ranging from 2100 to 4000 psia with the EPTD automated high pressure slimtube apparatus.

This report documents the slimtube experimental data. The phase behavior of the carbon dioxide slimtube displacements is also discussed.

CONCLUSION

The MMP for carbon dioxide displacing the Port Neches stock tank oil at 165°F is 3310 psia.

DISCUSSION

Oil Analysis

Two stock tank oils were sent from the Port Neches Field, well No. 6 and well No. 33. The oil from Well No. 33 was chosen because it had the heaviest gravity and the highest molecular weight. Also the oil from Well No. 33 contains significantly less hydrocarbon components between C_6 and C_{10} as shown in Fig. 1. All these factors indicate that the oil from Well No. 33 would give the highest MMP. The stock tank oil properties for each well are shown in Table 1 and Fig. 1. The carbon dioxide used in this study was obtained from LINDE Specialty Gases and was analyzed to contain 99.6 percent CO_2 and 0.4 percent N_2.

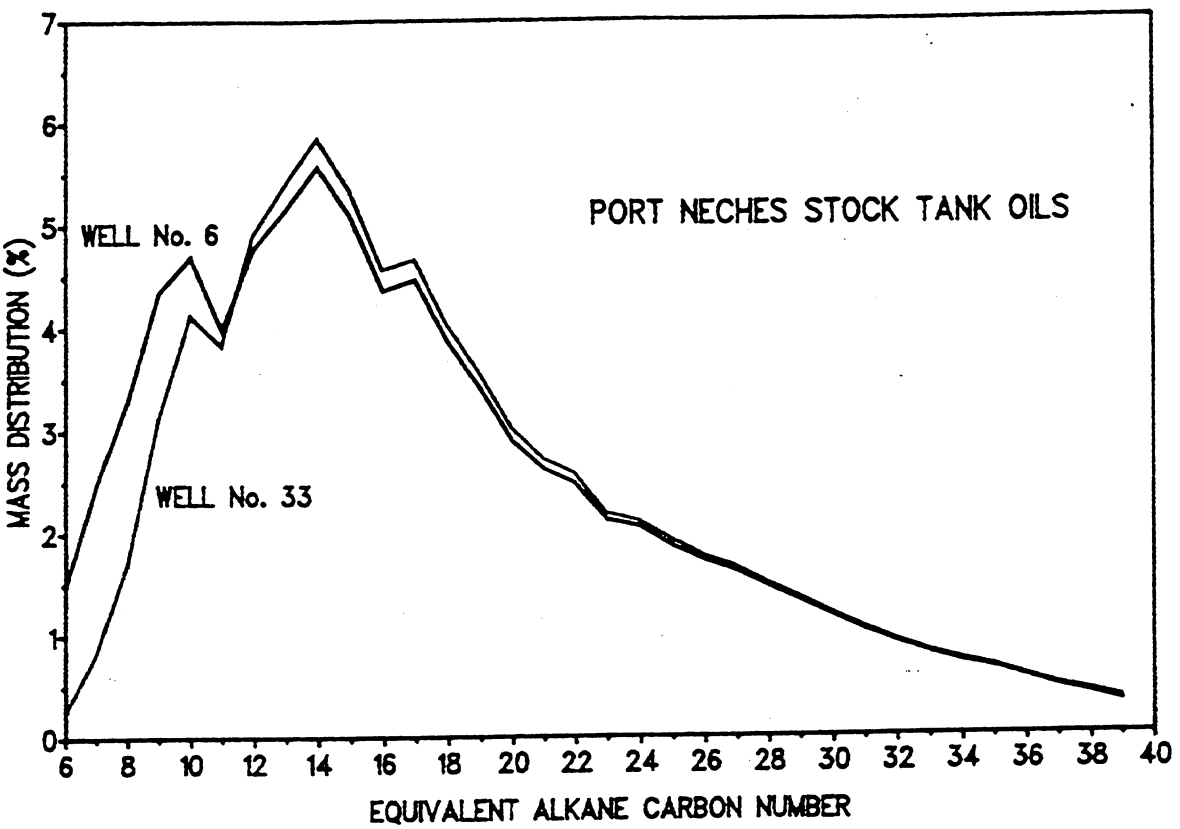

FIG. 1 - Oil composition of Port Neches oils.

Equipment

The schematic flow diagram of the automated high pressure slimtube apparatus used for this study is shown in Fig. 2. Details of the apparatus are described in Reference 1 which is available upon request. The slimtube is a 0.203 in. ID, 3/8 in. OD, 60 foot long, sandpacked stainless steel tube. The pumping rate for all the slimtube displacements was set at 25 cc/hr. The pore volume of the slimtube system from slimtube inlet to back pressure regulator is about 158.4 cc.

TABLE 1

Port Neches Stock Tank Oil Analysis

Carbon No.	Well No. 6		Well No. 33	
C_4-C_6	1.49		0.25	
C_7	2.48		0.83	
C_8	3.29		1.70	18.79%
C_9	4.35	25.07%	3.13	
C_{10}	4.70		4.13	
C_{11}	3.98		3.83	critical for CO2 displacement (higher amounts is better)
C_{12}	4.78		4.92	
C_{13}	5.16		5.41	
C_{14}	5.58		5.86	
C_{15}	5.10		5.35	
C_{16}	4.36		4.57	
C_{17}	4.47		4.67	
C_{18}	3.87		4.04	
C_{19}	3.41		3.56	
C_{20}	2.89		3.02	
C_{21}	2.62		2.72	
C_{22}	2.48		2.58	
C_{23}	2.12		2.19	
C_{24}	2.05		2.11	
C_{25}	1.86		1.93	
C_{26}	1.72		1.77	
C_{27}	1.61		1.66	
C_{28}	1.46		1.50	
C_{29}	1.32		1.36	
C_{30}	1.17		1.20	
C_{31}	1.03		1.06	
C_{32}	0.91		0.93	
C_{33}	0.80		0.82	
C_{34}	0.71		0.74	
C_{35}	0.65	21.68%	0.67	25.71% (lower amounts is better)
C_{36}	0.56		0.57	
C_{37}	0.46		0.48	
C_{38}	0.39		0.42	
C_{39}	0.31		0.35	
C_{40+}	15.86		19.67	
	100.00			
API Gravity	36.6		34.9	
Density (g/cc @ 60F)	0.8398		0.8486	
Molecular Weight	216		231	

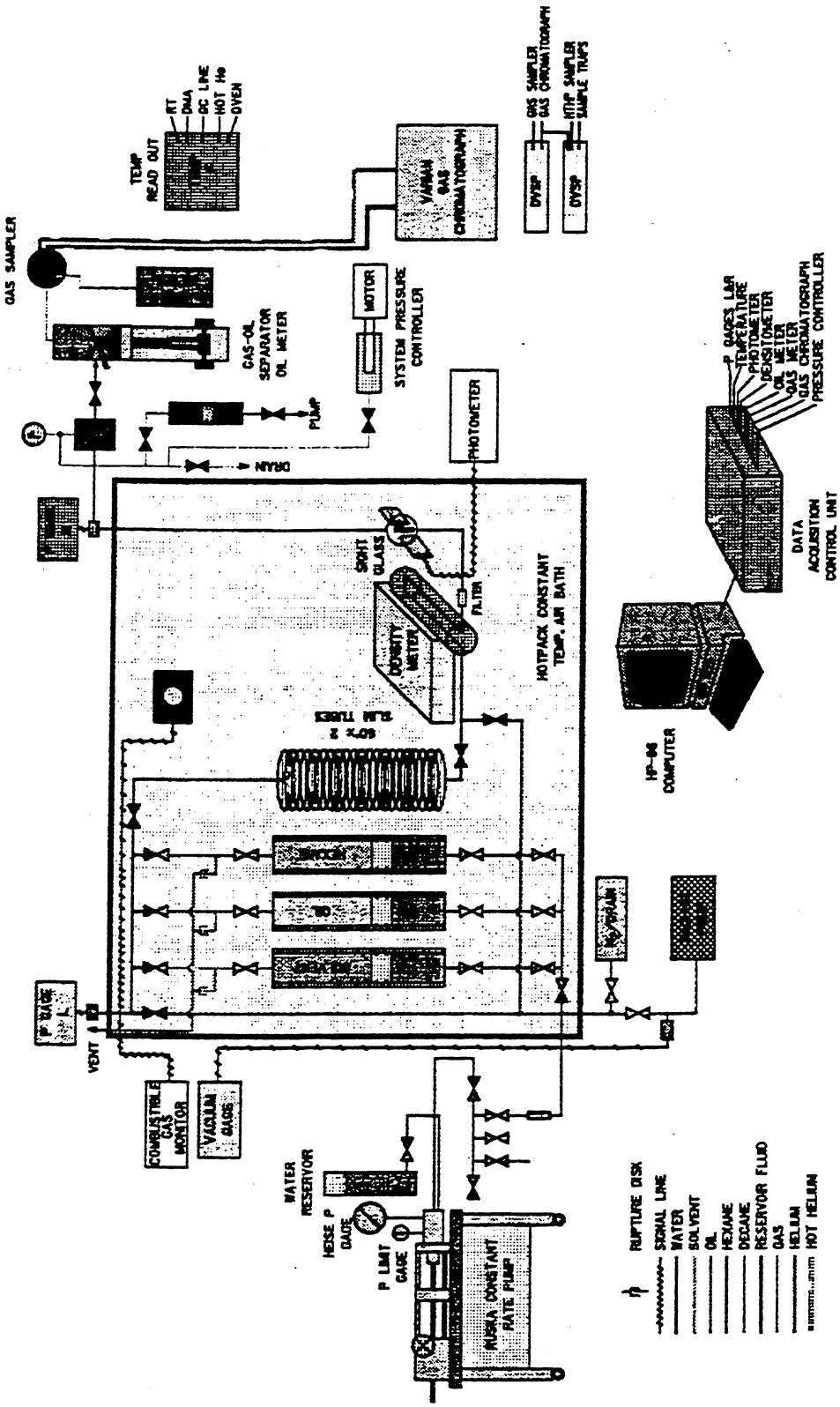

FIG. 2 - Schematic flow diagram of slimtube apparatus.

The slimtube was evacuated and saturated with decane at 165°F and at the experimental pressure. The slimtube pore volume was determined by the volume of decane displaced into the slimtube. Stock tank oil was then used to displace the decane for at least 1.3 pore volumes. The reported operating pressure was the pressure at the slimtube inlet which was kept constant by an automated pressure controller.[2]

Experimental Results

A series of Port Neches stock tank oil-carbon dioxide slimtube displacements were conducted at a temperature of 165°F and pressures ranging from 2100 to 4000 psia. The experimental results are summarized in Table 2. The unprocessed experimental data is available on request.

Gas breakthrough (GBT) used in this study is defined as the point the density of the displaced fluid begins to change significantly. It is expressed as the pore volume of carbon dioxide injected. Usually, a methane bank is observed before carbon dioxide breakthrough, for carbon dioxide slimtube displacements, at immiscible conditions with an oil containing methane. According to this GBT definition, the gas at GBT may not contain carbon dioxide. Reproducibility is very high when the GBT definition is used.

TABLE 2

Slimtube Results of Port Neches Stock Tank Oil-Carbon Dioxide System

Run Nº	122190	122090	122990	121990	122790	122690	122890
P, psia	2100	2500	2800	3000	3300	3500	4000
TEF (water)*	1.0207	1.0218	1.0225	1.0231	1.0235	1.0236	1.0235
CO_2 density (g/cc)	0.4261	0.5327	0.6004	0.6378	0.6826	0.7065	0.7525
Oil density (g/cc)	0.8275	0.8296	0.8310	0.8319	0.8332	0.8340	0.8360
B_o**	1.008	1.006	1.004	1.003	1.001	1.000	0.998
E_R at GBT (%)#	53.85	63.12	69.15	73.59	87.24	89.29	90.29
V_P @ GBT##	0.644	0.710	0.754	0.810	0.885	0.902	0.914
E_R @ 1.0 Vp	62.82	71.74	77.92	81.93	93.37	94.76	95.13
E_R @ 1.1 Vp	64.13	72.98	79.57	83.92	94.61	95.79	96.18
Miscibility*#	IM	IM	NEAR	NEAR	NEAR	MCM	MCM

* TEF (water) = Thermal Expansion Factor of water
** B_O = Oil formation volume factor
\# E_R at GBT = Oil recovery efficiency at Gas BreakThrough
V_P = pore volume of CO_2 injected
*# IM = immiscible; MCM = multicontact miscible.

Analysis

Oil Recovery Efficiency

Fig. 3 shows the slimtube oil recovery efficiency as a function of the pore volumes of carbon dioxide injected at 165°F and the indicated pressure.

The slimtube displacement at 2100 psia (Fig. 2) shows a low oil recovery efficiency and an early gas breakthrough (Table 1) at 0.64 Vp which indicates immiscible displacement. As the system pressure is increased, the oil recovery efficiency increases rapidly until about 3300 psia.

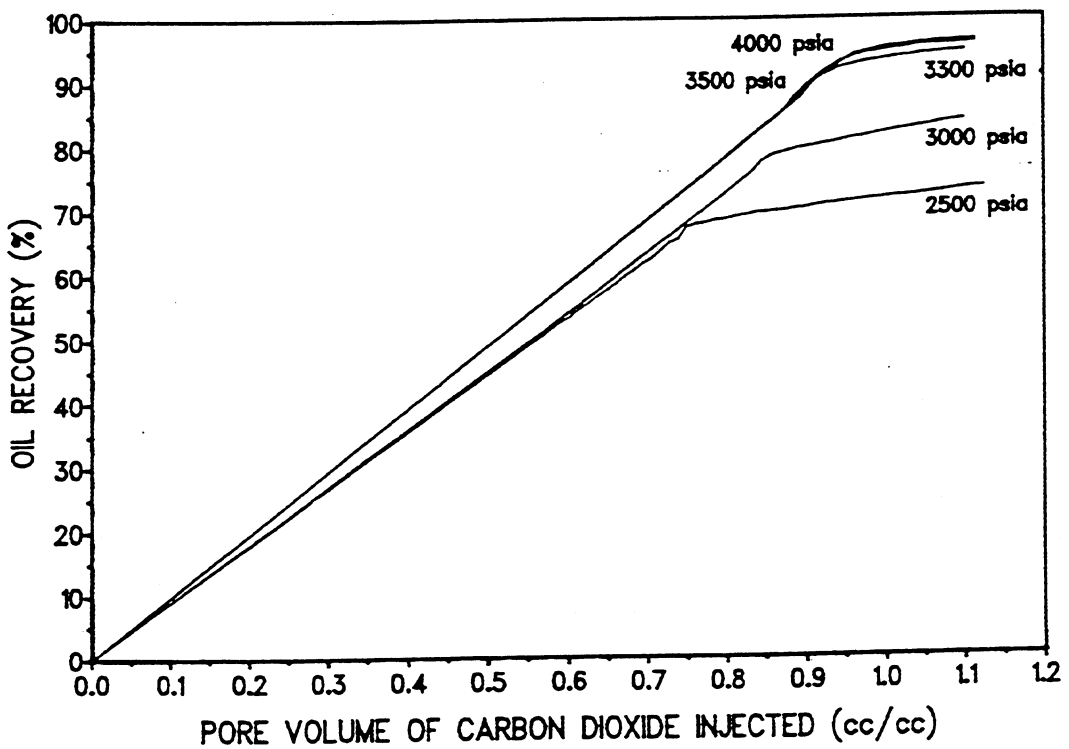

FIG. 3 - Oil recovery efficiency versus pore volume of carbon dioxide injected.

Fig. 3 is a plot of the oil recovery efficiency (E_R) at gas breakthrough (GBT) versus the displacement pressure. The curve of $E_{R(GBT)}$ breaks sharply at 3310 psia. The break point of the $E_{R(GBT)}$ curve is used to pinpoint the MMP. As can be seen in Fig. 4, at immiscible conditions the curve is linear until just before the MMP where it curves sharply. This is commonly seen in stock tank oils. The MMP determined by this method is consistent with the observed phase behavior of slimtube tests.

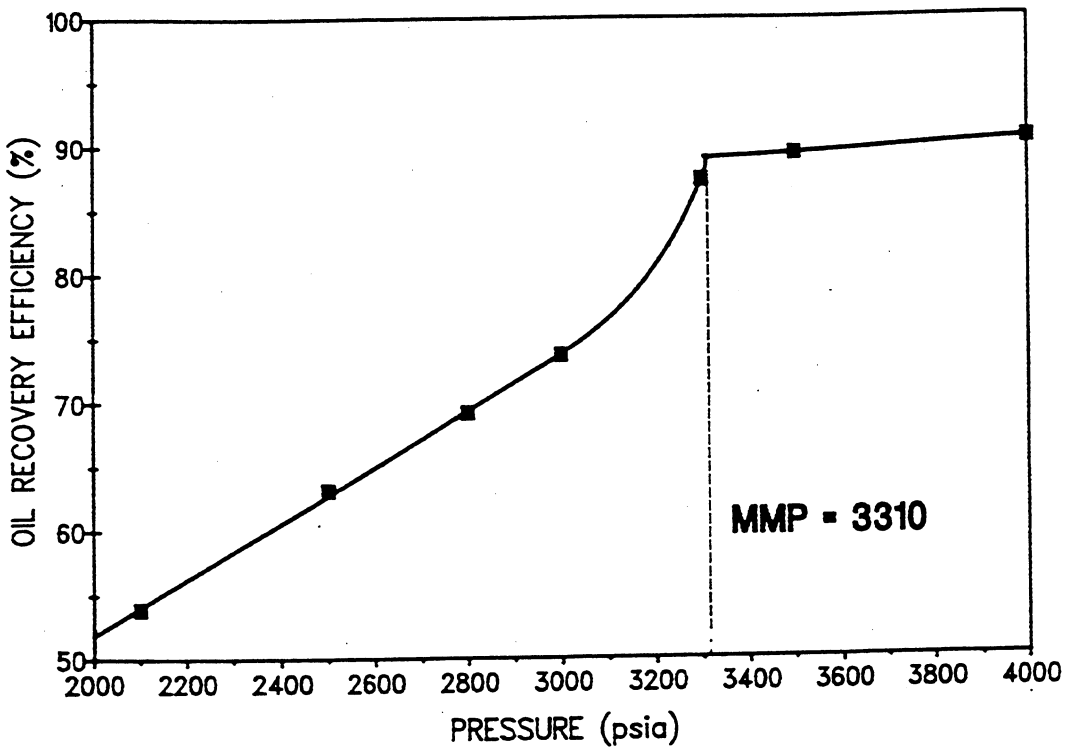

FIG. 4 - Oil recovery efficiency versus pressure.

Density and Photoresponse of the Displaced Fluid

A density meter and a sight glass in the slimtube apparatus was used to monitor phase changes of the displaced fluid. The pressure limit is 6000 psia for the density meter and 10,000 psia for the sight glass. The histories of density and photoresponse of the displaced fluid in the slimtube displacements are shown in Fig. 5. A video camera system was used to record the phase change of the displaced fluid observed through the sight glass. The sight glass has a height of 1/16 in. and a width of 1/4 in. The camera magnifies the sight glass approximately 400X to give an image of 1.5 X 4.5 inches. Recorded video tapes for the displacements are available on request.

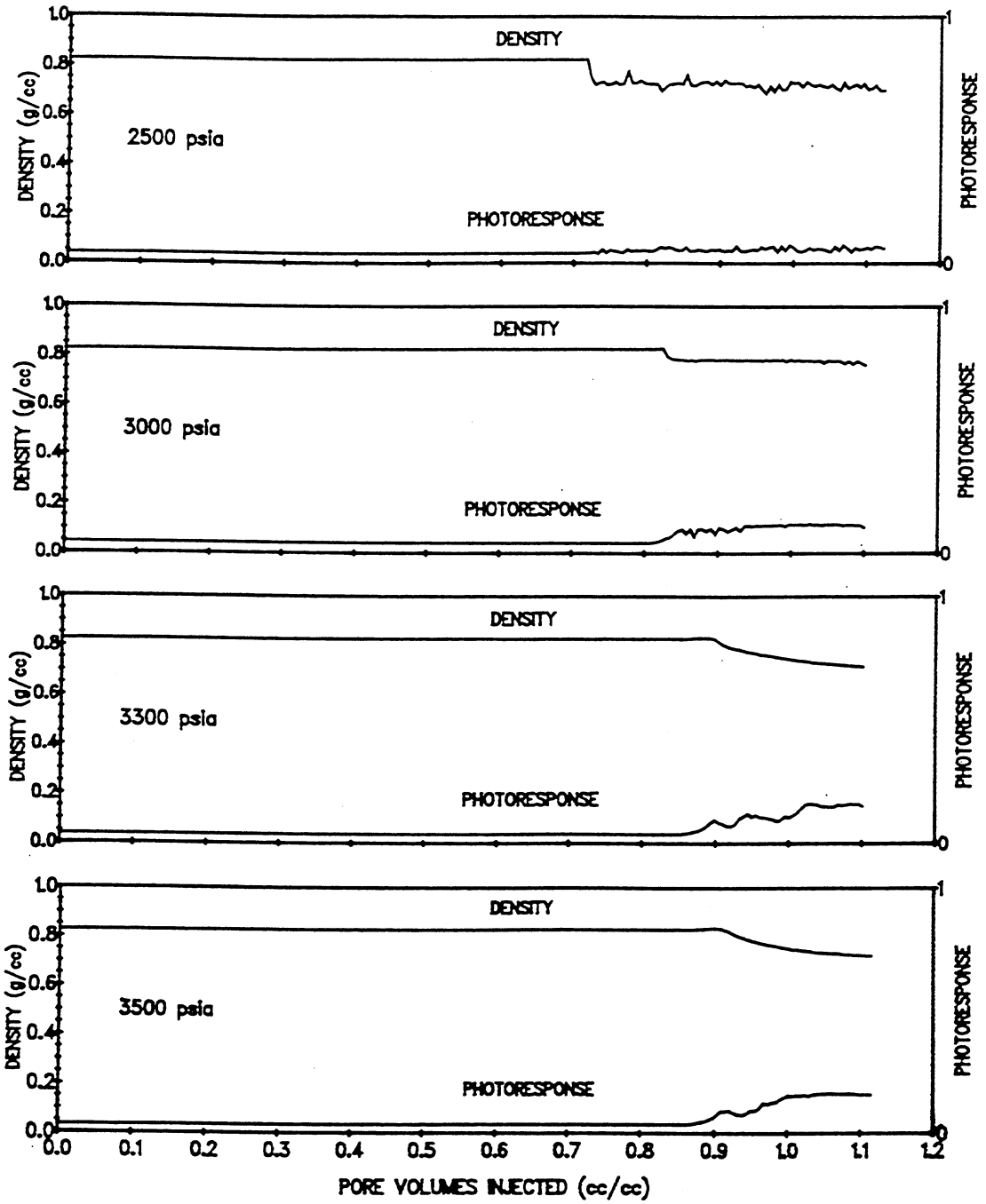

FIG. 5 - Density and photoresponse histories of the displaced fluid.

The density and photoresponse histories shown in Fig. 5 and the recorded phase phenomena in the video tapes show the following phase behavior:

1. At 2100 and 2500 psia, large gas bubbles of carbon dioxide filling the sight glass (greater than 1/16 in. diameter) were observed after gas breakthrough. The density and photoresponse histories show erratic changes from about gas breakthrough to the completion of the experiment. Compared to the video observations, the erratic changes of density and photoresponse indicate the presence of gas bubbles.

2. At 2800 and at 3000 psia the phase changes were similar to that described above, but the gas bubbles are smaller and two phase flow follows.

3. At 3300 psia, the color of the displaced fluid flowing through the sight glass after gas breakthrough changed from black, to dark red, to red. No gas bubbles were observed, but a two-phase flow was observed to the end.

4. At 3500 and 4000 psia the color of the displaced fluid changed from black to dark red, to red, to finally a very light red. No gas bubbles were observed. A smoky yellow phase was observed in the top portion of the sight glass for a short period of time. The density history shows a smooth change after gas breakthrough for the 3500 and 4000 psia runs.

The observation of the above phase behavior demonstrates that the slimtube displacements were immiscible at pressures below 3300 psia, were near miscible or multicontact miscible between 3300 and 4000 psia.

Carbon Dioxide MMP of a Stock Tank Oil and a Live Oil

Previous work at EPTD has shown that the CO_2 MMPs of a stock tank oil (STO) and a live oil from the same STO are about the same. This is due to the nature of the carbon dioxide recovery mechanisms. The two live oils studied at EPTD were Erath and Duhe oils, which contained a high concentration of methane (greater than 40 mole %). The presence of methane has no measurable effect on the CO_2 MMP.[3] The literature also states that the presence of C_1 - C_4 has no effect on CO_2 MMP.[4] This is the reason why early MMP correlations used stock tank oil API gravity or C_{5+} molecular weight as correlating factors.[5,6,7]

The Port Neches field is currently below the bubble point pressure of the oil, therefore the gas composition is unknown or highly variable. For this reason the MMP was determined on the stock tank oil. The CO_2 MMP of the Port Neches stock tank oil should be very close to that of its live oil.

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PRIORITY STATUS BIT-CUTTINGS LITHOLOGIC DESCRIPTION OF CONVENTIONAL CORE, PREPARATION FOR CUTTINGS IDENTIFICATION FROM A HORIZONTAL WELLBORE

TEXACO DEEP UNIT 6-6-D WELL

NEW HOPE FIELD, FRANKLIN COUNTY, TEXAS

EXP - TECHNICAL MEMORANDUM: Priority Status Bit-Cuttings Lithologic Description of Conventional Core, Preparation for Cuttings Identification from a Horizontal Wellbore
Texaco Deep Unit 6-6-D Well
New Hope Field
Franklin County, TX

prepared by

Brian E. O'Neill

Texaco Exploration and Production - East Region
Geotechnical Services - Geologic Lab
September, 1991

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prepared by

´Brian E. O'Neill

Texaco Exploration and Production - East Region
Geotechnical Services - Geologic Lab

September, 1991

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DATE: September 20, 1991

TO: Jerome Ellard

FROM: Brian O'Neill

SUBJECT: **EXP - TECHNICAL MEMORANDUM:**
Lithologic Description of Conventional Core;
Analysis of Lithology to Prepare for Horizontal Drilling

Well: Texaco Deep Unit No. 6-6-D
Field: New Hope
Formation: Petit, Pittsburgh "C" sand-member (Hauterivian)
Location: Franklin County, Texas

Within the very near future Texaco Onshore Producing Assets West will drill a horizontal well through the oil-productive Pittsburgh "C" sand-member of the lowermost Petit Formation. Horizontal displacement through the Pittsburgh "C" should exceed 2000'. The Pittsburgh "C" typically ranges in vertical thickness from 25-40' within the New Hope Field and local well control suggests thickness of 30 feet in the vicinity of the proposed well. It will be critically important to maintain vertical control during horizontal drilling through the productive interval. Stratigraphic control at the wellsite will be based largely on cuttings collected during horizontal drilling. The main purpose of this study is to establish lithologic characteristics of the Pittsburgh "C" sand, the units that immediately overlie and underlie it, and describe the vertical succession within the Pittsburgh "C". This vertical succession will be used to provide stratigraphic control within the proposed well. Establishing vertical stratigraphic control will be inherently difficult since the shales that underlie and overlie the Pittsburgh "C" are thin (<5'), and sandstone units above and below the Pittburgh "C" are lithologically similar to it.

Initial vertical lithologic and biostratigraphic descriptions of the Pittsburgh "C" were made using cuttings from three wells, the 4-4-D, 4-6-D, and 6-1-D. Examination of the cuttings from these wells failed to establish consistent patterns of vertical lithology. Two of the wells (4-4-D, 6-1-D) display highly variable sandstone lithologies (with no clear-cut vertical succession) and cuttings showed poor agreement with wireline logs. Biostratigraphic analyses (foraminifera and calcareous nannofossils) were also conducted on cuttings from the three wells. Fauna identified from these cuttings were almost entirely Albian and younger in age, indicating that the cuttings samples were contaminated with uphole cavings (personal communication, R. Lytton, J. Boudreaux). Recognition of this contamination complicated visual lithologic descriptions of the cuttings samples. Based on these analyses it appeared evident that cuttings would not be useful in establishing

Table 1: Sample Depths and Analyses Performed			
Sample Depth	Thin Section	Foraminifera	Calcareous Nannofossils
8005.0		X	X
8006.6	X		
8009.3		X	
8010.0	X		
8013.0	X		
8014.4	X		
8017.3	X		
8020.8	X		
8021.3	X		
8028.4	X		
8031.2	X		
8031.4	X		
8032.5	X		
8033.3	X		
8033.9	X		
8034.0		X	X
8035.3	X		

TABLE 2: LITHOLOGIC DESCRIPTIONS OF THE CORED INTERVAL

Depth Interval of Conventional Core	Lithology	Appearance of Cuttings-sized Core Chips	Unit	Remarks
8004-8005	dark gray shale	well lithified, dark gray ringtail shale	1	
8005-8011	highly-mottled greenish-black siltstone	variegated and distinctly mottled, patchy color variations include black, dark green, light green, and tan; core chips look remarkably similar to army camouflage; this bioturbated interval consists largely of siltstone but also contains shale and very fine-grained sandstone.	2	This is a somewhat thick and distinctive lithology; cuttings should be highly variable in color within this unit; individual cuttings may show more than one color.
8011-8014	light green coarse siltstone/ v. fine grained sandstone	light green coarse siltstone and lower very fine-grained sandstone.	3	The light green color of this siltstone/sandstone interval should prove to be a useful indicator for drilling upwards out of the zone.
8014-8018	medium gray very fine- to fine-grained sandstone	medium gray very fine- to fine-grained sandstone; cuttings should contain minute flecks of dark black matter (reservoir bitumen) in addition to hydrocarbon shows.	4	This unit is tighter and less porous than the underlying sandstone, but will be difficult to distinguish from the underlying sandstone unit using cuttings.
8018-30	light gray fine-grained sandstone	light gray fine-grained sandstone; cuttings should contain minute flecks of dark black matter (reservoir bitumen) in addition to hydrocarbon shows.	5	This unit is relatively porous and represents the heart of the pay sand; rates of penetration should be highest in this interval; slightly coarser grain-size (0.13-0.18mm); thin (<1.0') calcareous-cemented beds are possible.
8030-8033	light brown very fine- to fine-grained sandstone	light brown very fine- to fine-grained sandstone	6	This unit is tighter and less porous than the overlying sandstone, but will be difficult to distinguish from the overlying sandstone unit using cuttings.
8033-8034.5	limestone-conglomerate and greenish-gray shale	interbedded limestone conglomerate and shale; shale is dark gray with a faint greenish hue; conglomerate beds are thin (< 6") and contain well rounded limestone pebbles and angular pelecypod fragments; many of the pelecypod fragments are dark brown and have a greasy translucent appearance.	7a 7b	Cuttings of the limestone conglomerate beds may appear similar to those of the much thicker upper mottled siltstone unit; translucent dark brown pelecypod fragments within this unit are unique in this interval; highly calcareous interval; thin conglomerate beds may not have extensive lateral continuity (they could be absent within parts of the field).
8034.5-35	stylolitic very fine-grained sandstone	light gray, well indurated very fine-grained sandstone containing black stylolite seams.	8	Black stylolites are distinctive within this interval; the sandstone tends to break (cleave) along the stylolites and therefore stylolites may be rare within individual cuttings.

APPENDIX A: GENERAL THIN SECTION DESCRIPTIONS

Table 2: Thin Section Petrographic Data

SAMPLE DEPTH (ft):	8006.6	8010.0
Lithology:	Bioturbated, dolomitic shaley siltstone	Bioturbated coarse-grained siltstone and silty shale
Lithification:	Well	Well
Sedimentary features:	complex burrow-mottled fabric resulting in variable lithologies which include shaley siltstone, silty shale, and dolomite. Dolomite appears to have replaced clay-rich lithologies.	complex burrow-mottled fabric resulting in variable lithologies which include siltstone, shale, siderite, and dolomite. Siderite and dolomite appear to have replaced clay-rich lithologies.
Average grain size:	0.06 mm (coarse siltstone)	0.06 mm (coarse siltstone)
Overall sorting:	n/a	n/a
Framework components:	monocrystalline quartz > plagioclase feldspar > micas > chert, heavy minerals	monocrystalline quartz > plagioclase feldspar > micas > chert, heavy minerals
Cement content:	Fe-dolomite is abundant occurring as a pore-fill between siltstone grains and a fabric-replacement cement.	Fe-dolomite is abundant occurring as a pore-fill between siltstone grains and a fabric-replacement cement; siderite cement appears to have replaced detrital clays within localized clay-filled burrows.
Dispersed clays:	Detrital clay is common between framework grains but is unevenly distributed.	moderate amounts of detrital clay is concentrated within oval burrows
Authigenic clays:	none identified	none identified
Porosity Development:	very poor; microporous pore system	very poor; microporous pore system.

Table 2: Thin Section Petrographic Data

SAMPLE DEPTH (ft):	8020.8	8021.3
Lithology:	upper fine-grained sandstone	fine-grained sandstone
Lithification:	Well	Well
Sedimentary features:	massive fabric	massive fabric; more than half of the sample is tightly cemented by calcite; this calcite cemented portion of the sample is part of a large calcite concretion
Average grain size:	0.22 mm (fine-grained sandstone)	0.22 (upper fine-grained sandstone)
Overall sorting:	well	well
Framework components:	monocrystalline quartz > polycrystalline quartz > plagioclase feldspar, chert, rock fragments > heavy minerals	monocrystalline quartz > polycrystalline quartz, K-feldspar, plagioclase feldspar, rock fragments > micas, chert, heavy minerals
Cement content:	quartz overgrowths are well developed and evenly distributed; minor patchy pore-filling Fe-dolomite.	most of the sandstone is tightly cemented by pore-filling Fe-calcite cement; about 1/4 of the thin section sample contains only minor amounts of calcite cement but contains moderate amounts of quartz-overgrowth cement as well as minor amounts of patchy pore-filling Fe-dolomite.
Dispersed clays:	trace pseudomatrix	Minor amounts of pseudomatrix; minor amounts of reservoir bitumen
Authigenic clays:	minor amounts of pore-filling kaolinite	none identified
Porosity Development:	very good; intergranular pores are abundant, evenly distributed, and well interconnected; moderate amounts of grain-moldic secondary dissolution porosity.	moderate; the majority of the sample is tightly cemented and displays negligible visible porosity; intergranular porosity is well developed within the portion of the sample lacking calcite; based on visual examination of the core, the calcite cemented zone appears restricted to a 1 foot interval at 8021.3.

Table 2: Thin Section Petrographic Data

SAMPLE DEPTH (ft):	8028.4	8031.2
Lithology:	lower fine-grained sandstone	silty shaley very fine-grained sandstone
Lithification:	Well	Well
Sedimentary features:	massive fabric	wavy burrow-mottled fabric consisting largely of silty sandstone with occasional clay-rich burrows.
Average grain size:	0.17 mm (v. fine sandstone)	0.09 (v. fine sandstone)
Overall sorting:	well	n/a
Framework components:	monocrystalline quartz > plagioclase feldspar, chert, polycrystalline quartz, rock fragments > heavy minerals	monocrystalline quartz > plagioclase feldspar > micas > chert, heavy minerals
Cement content:	quartz overgrowths are well developed and evenly distributed; minor patchy pore-filling Fe-dolomite.	small amounts of quartz cement; minor Fe-dolomite.
Dispersed clays:	trace pseudomatrix; minor amounts of reservoir bitumen	Detrital clays are abundant, occurring within intergranular pores and, less commonly, concentrated within oval burrows.
Authigenic clays:	minor amounts of pore-filling kaolinite	none identified
Porosity Development:	good; intergranular pores are abundant, evenly distributed, and well interconnected; moderate amounts of grain-moldic secondary dissolution porosity.	very poor; microporous pore system.

Table 2: Thin Section Petrographic Data

SAMPLE DEPTH (ft):	8031.4	8032.5
Lithology:	lower fine-grained sandstone	fine-grained sandstone
Lithification:	Well	Well
Sedimentary features:	laminated; laminations are slightly wavy and horizontal trending; some laminations contain high amounts of detrital clay; pebble-sized rip-up clasts are common along one lamination; rip-clasts include shale and limestone clasts.	laminated; laminations are faint and planar
Average grain size:	0.15 mm (fine sandstone)	0.14 (fine sandstone)
Overall sorting:	well	well
Framework components:	monocrystalline quartz > plagioclase feldspar, polycrystalline quartz, rock fragments, chert > heavy minerals	monocrystalline quartz > plagioclase feldspar, chert > micas, rock fragments, heavy minerals
Cement content:	Fe-calcite is quite common within intergranular areas; poorly developed quartz overgrowth cement.	Quartz overgrowth cement is abundant and evenly distributed; Fe-dolomite cement is common, occurring mostly as a pore-filling cement and less commonly as a grain replacement cement.
Dispersed clays:	Detrital clays are common along thin laminations (<1.5mm); minor amounts of reservoir bitumen.	minor pseudomatrix; many pores are lined by reservoir bitumen.
Authigenic clays:	none identified	none identified
Porosity Development:	very poor; microporous pore system	moderate; intergranular pores are diminished in size due to quartz cement; grain-moldic secondary dissolution pores are common but do not appear well interconnected.

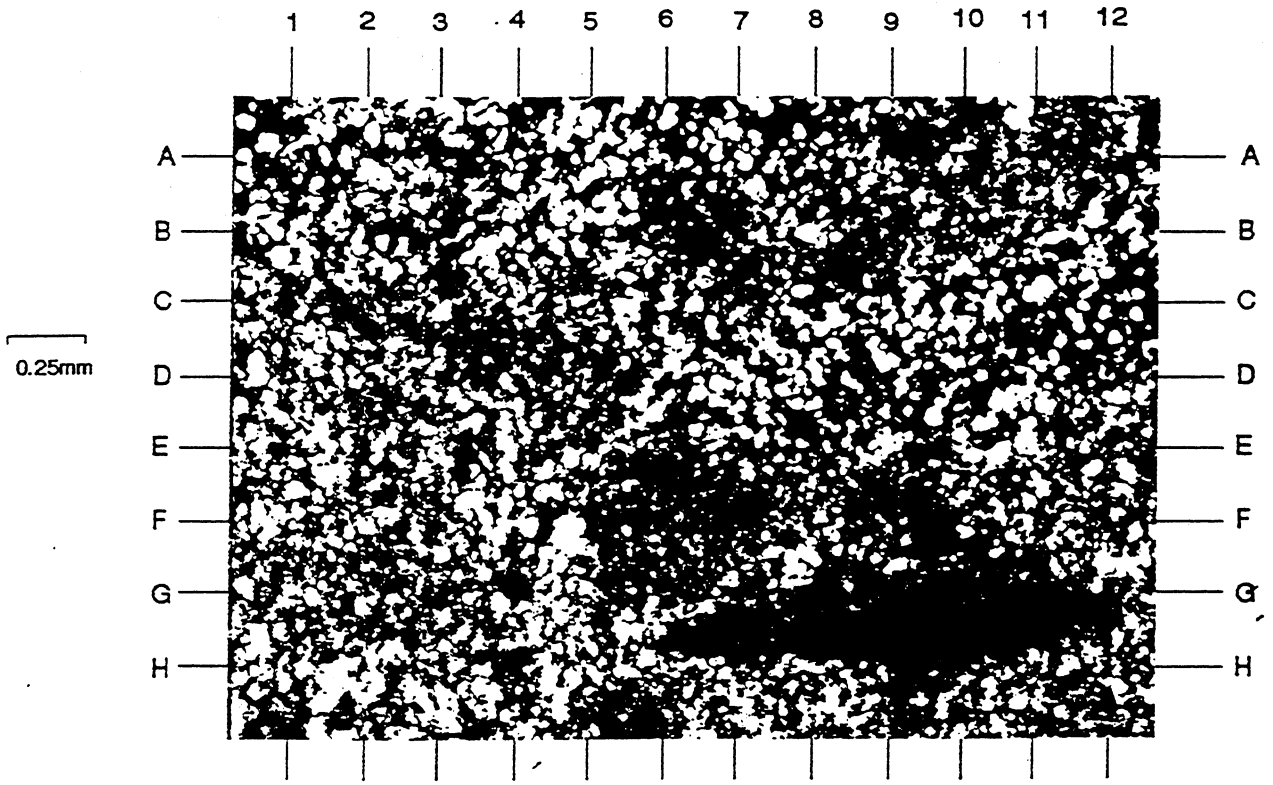
Table 2: Thin Section Petrographic Data

SAMPLE DEPTH (ft):	8033.3	8033.9
Lithology:	interlaminated very fine-grained sandstone and coarse-grained siltstone	sandy limestone conglomerate
Lithification:	Well	Well
Sedimentary features:	laminated; laminations are slightly wavy and horizontal trending; some laminations contain high amounts of detrital clay; pebble-sized rip-up clasts are common along one lamination; rip-clasts include shale, limestone clasts, and pelecypod shell fragments.	massive distribution of granule- to pebble-sized limestone clasts and calcareous pelecypod shell fragments.
Average grain size:	0.05/.09 mm (fine sandstone)	2.80. (granule)
Overall sorting:	n/a	poor
Framework components:	monocrystalline quartz > plagioclase feldspar, polycrystalline quartz, rock fragments, chert > intrabasinal grains, K-feldspar, heavy minerals	limestone clasts, pelecypod shell fragments, monocrystalline quartz > plagioclase feldspar
Cement content:	quartz overgrowth cement is abundant; Fe-calcite and Fe-dolomite are common pore-filling cements that are unevenly distributed; minor pyrite.	Calcite cement is abundant
Dispersed clays:	Detrital clays are common along thin (<1.5mm) laminations; reservoir bitumen is common within pores.	minor pseudomatrix
Authigenic clays:	none identified	none identified
Porosity Development:	poor; microporous pore system	poor; tightly cemented with rare grain-moldic secondary dissolution pores.

Table 2: Thin Section Petrographic Data	
SAMPLE DEPTH (ft):	8035.3
Lithology:	very fine-grained sandstone
Lithification:	Well
Sedimentary features:	laminated; laminations are faint and horizontal trending; contains several horizontal-trending stylolites
Average grain size:	0.09 mm (fine sandstone)
Overall sorting:	well
Framework components:	monocrystalline quartz > plagioclase feldspar, polycrystalline quartz, rock fragments, chert > heavy minerals
Cement content:	quartz cement is abundant and evenly distributed; Fe-dolomite occurs in small amounts.
Dispersed clays:	Detrital clays are common along stylolites; minor amounts of reservoir bitumen and pseudomatrix.
Authigenic clays:	none identified
Porosity Development:	poor; microporous pore system

APPENDIX B: THIN SECTION PHOTOMICROGRAPHS

Note: Thin section samples were impregnated with a blue-dyed epoxy, therefore pores visible within the thin-section photomicrographs appear light blue. The thin sections were also stained with alizarin red S and potassium ferricyanide which impart a pink-red color to calcite, purple color to iron-rich calcite, and a dark blue color to ankerite. Ankerite cement is common within many of the samples and care should be taken to distinguish ankerite (dark blue with high relief) from visible pores (light blue with very low relief) in these photomicrographs.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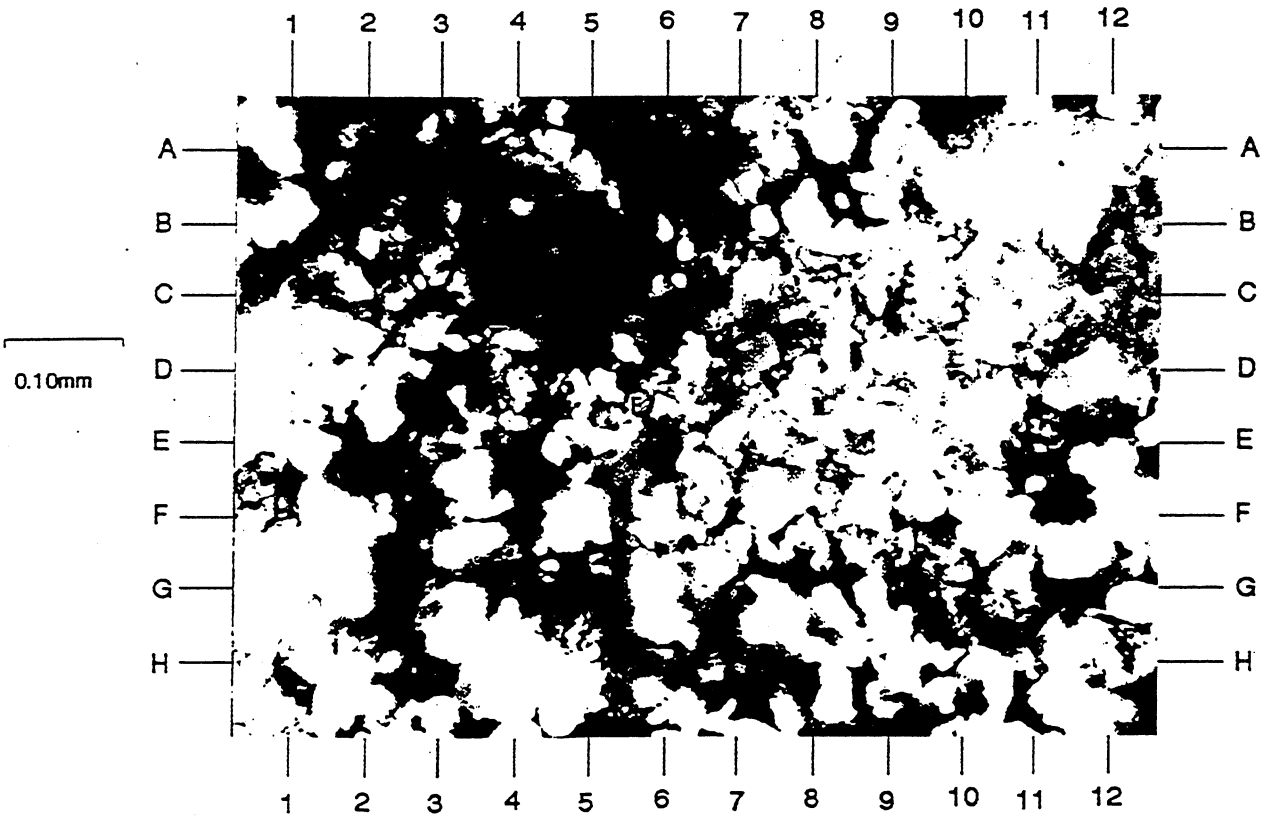
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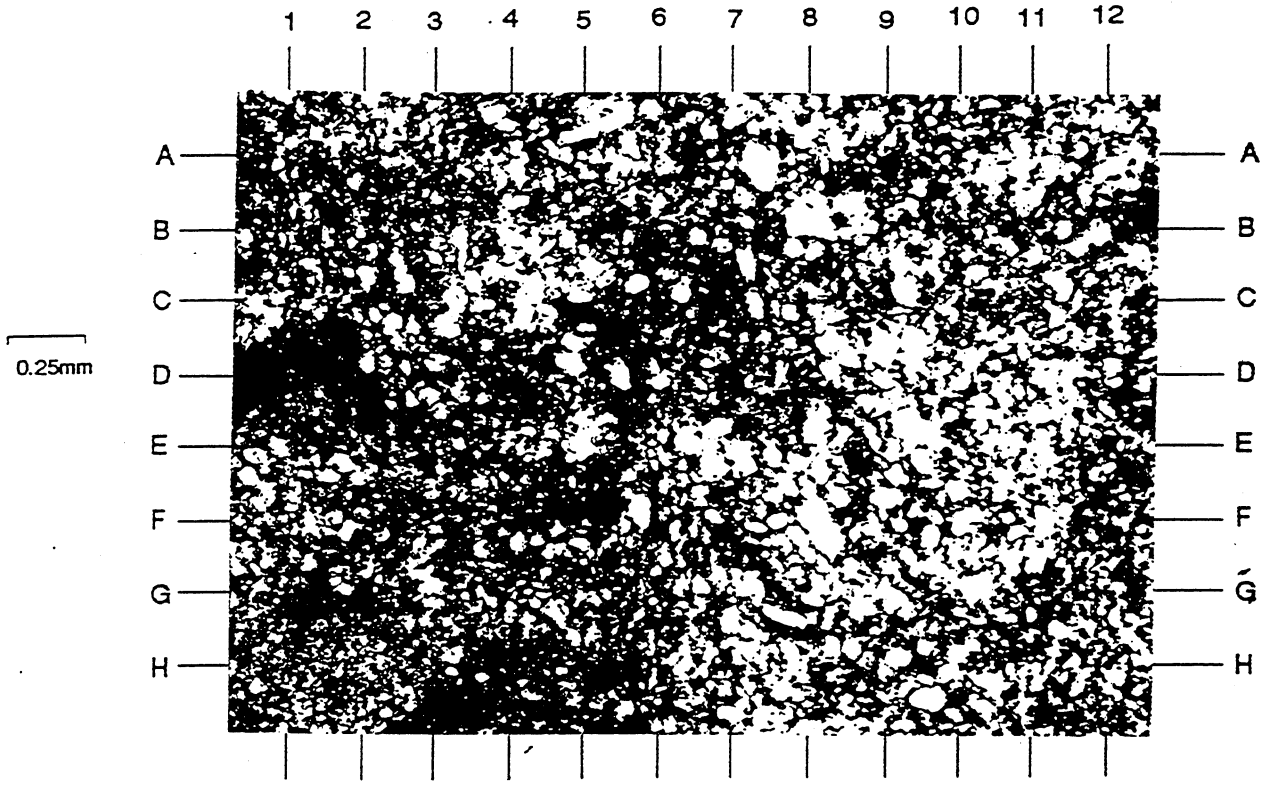
Plate 2A: 8010.0 Feet Bioturbated shaley siltstone and silty shale are displayed in this low magnification thin section photomicrograph. (40X: Plane polarized light)

Plate 2B: 8010.0 Feet An enlarged view of the area near E8 in Plate 2A is displayed in this high magnification photomicrograph. Detrital clay (light brown at arrows) and Fe-dolomite (blue-stained rhombic crystals) occlude intergranular pore-space between detrital framework grains. (160X: Plane polarized light)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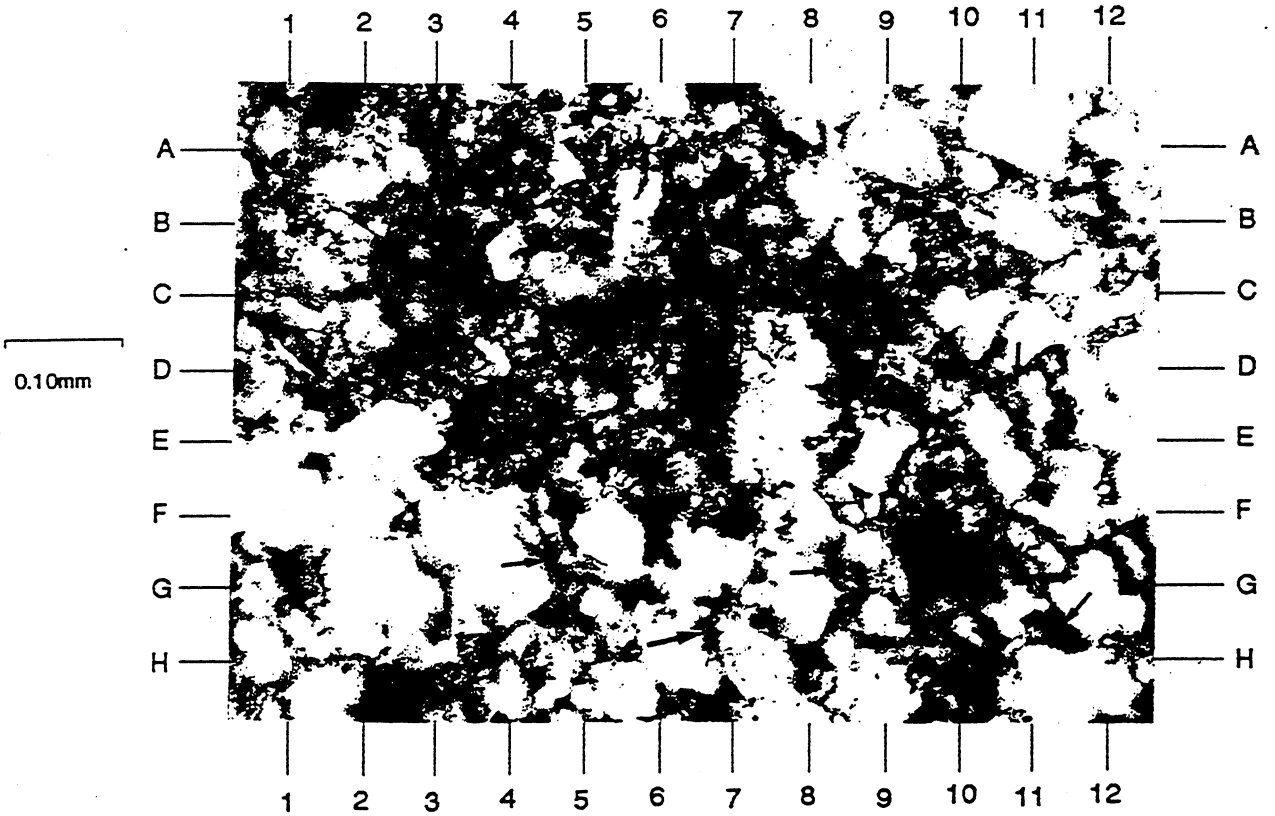
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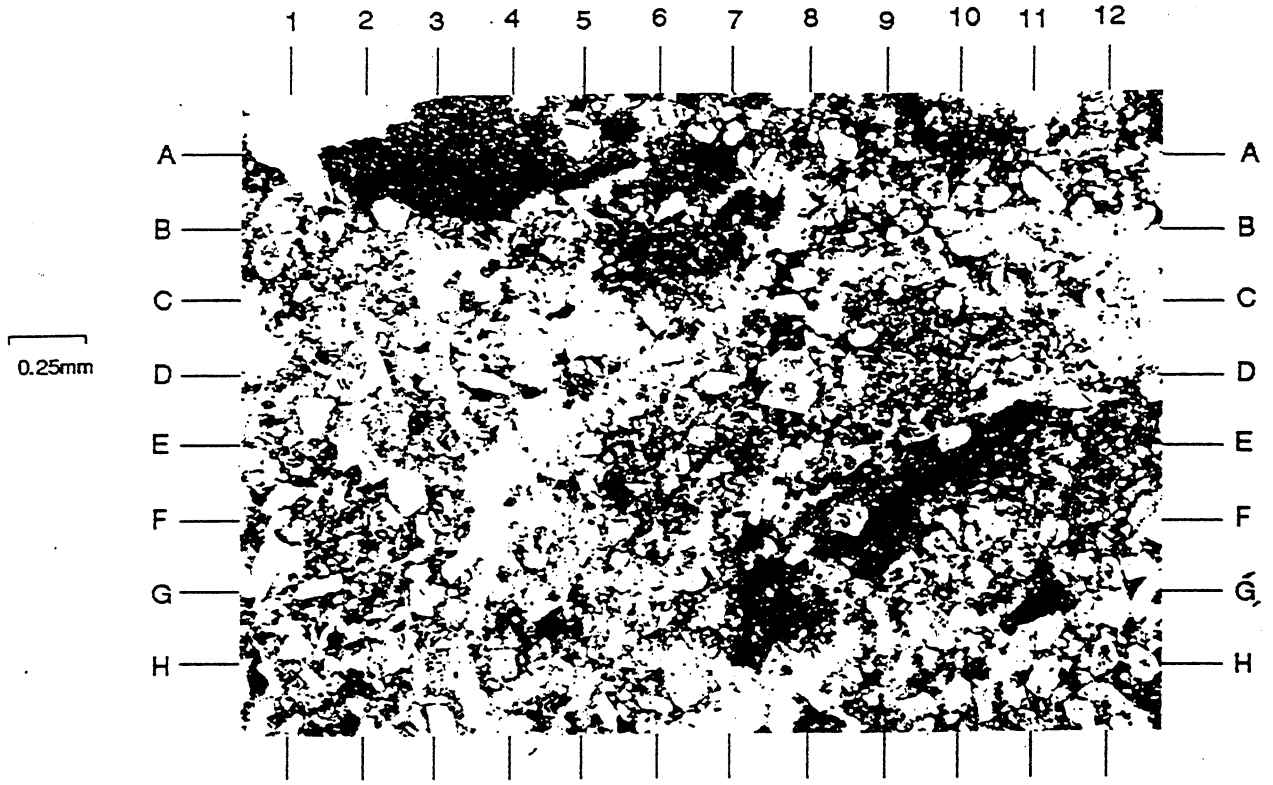
Plate 3A: 8011.7 Feet This low magnification thin section photomicrograph displays a burrow-mottled silty shaley very fine-grained sandstone. Note the concentrated patches of detrital clay near A3 and F9.5. (40X: Plane polarized light)

Plate 3B: 8011.7 Feet An enlarged view of the area near G7 in Plate 3A is displayed in this high magnification photomicrograph. Detrital clay occurs in isolated patches (A4, D10-H9). Blue-stained rhombic crystals of Fe-dolomite (F) cement are scattered in distribution. (160X: Plane polarized light)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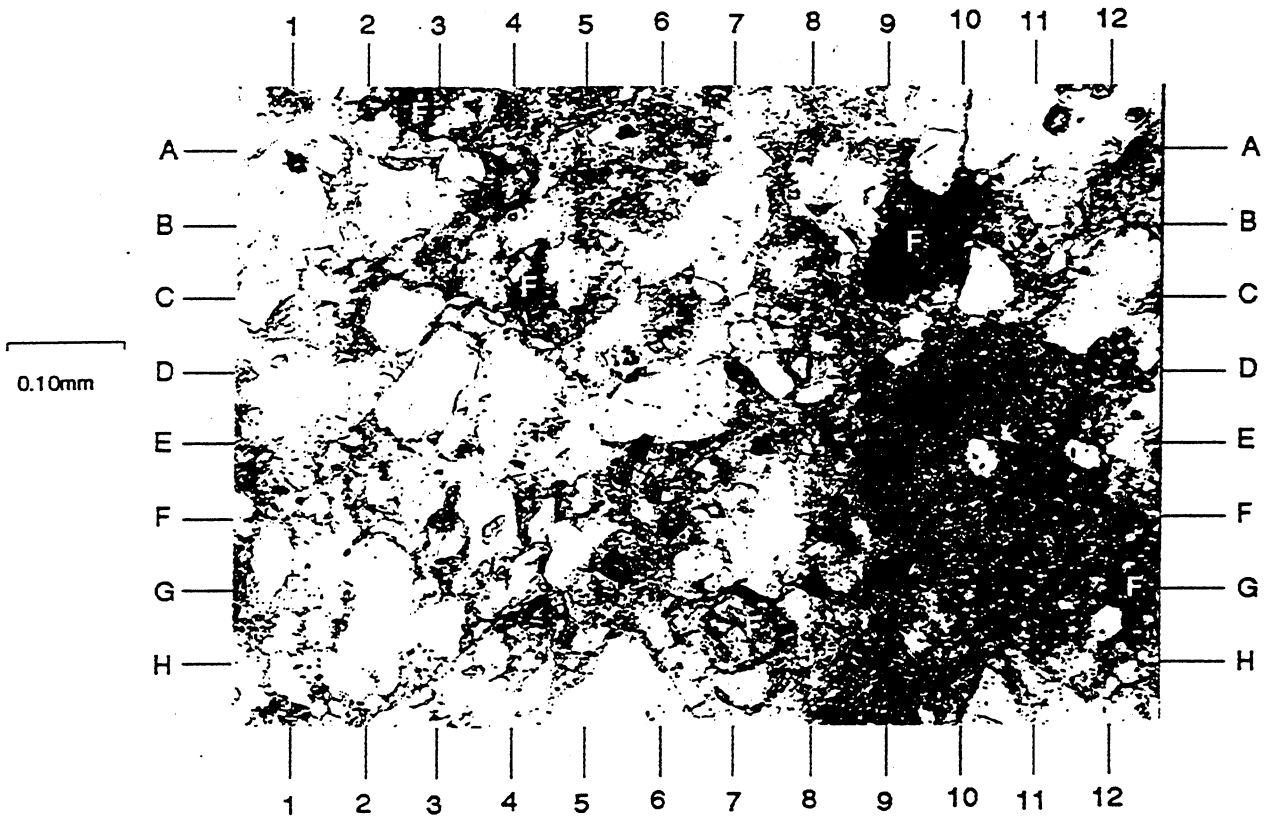
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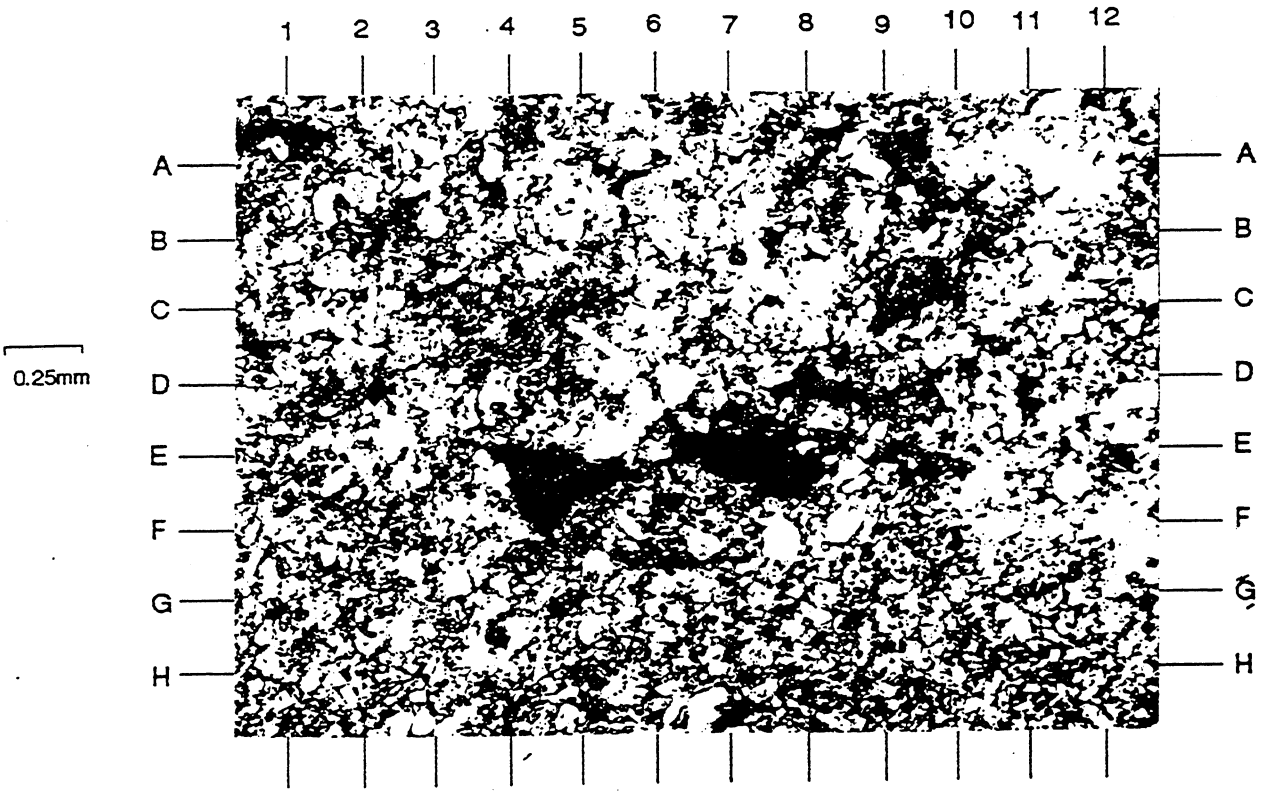
Plate 4A: 8013.0 Feet Bioturbated silty shaley very fine-grained sandstone is displayed in this low magnification thin section photomicrograph. (40X: Plane polarized light)

Plate 4B: 8013.0 Feet An enlarged view of the area near E7 in Plate 4A is displayed in this high magnification photomicrograph. Detrital clay (light brown at arrows) and Fe-dolomite (blue-stained rhombic crystals) occlude intergranular pore-space between detrital framework grains. (160X: Plane polarized light)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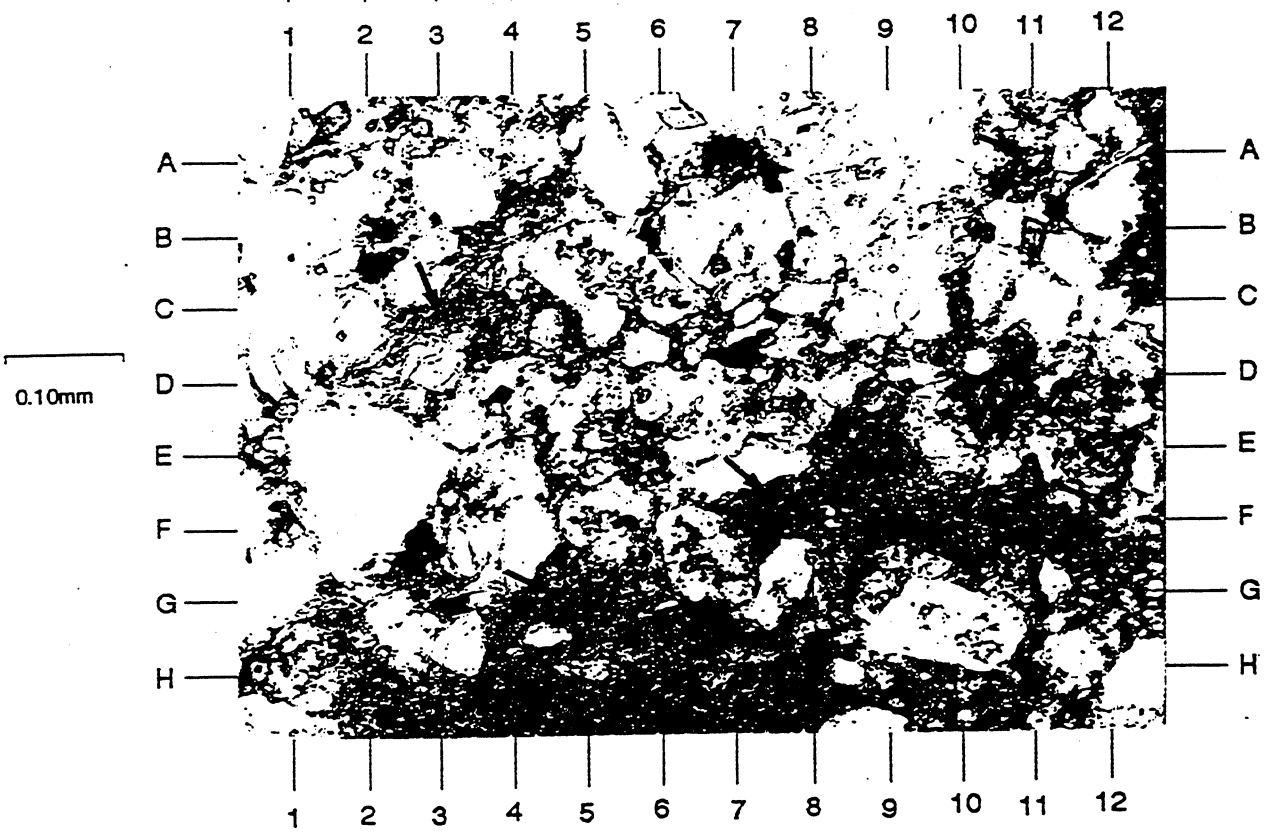
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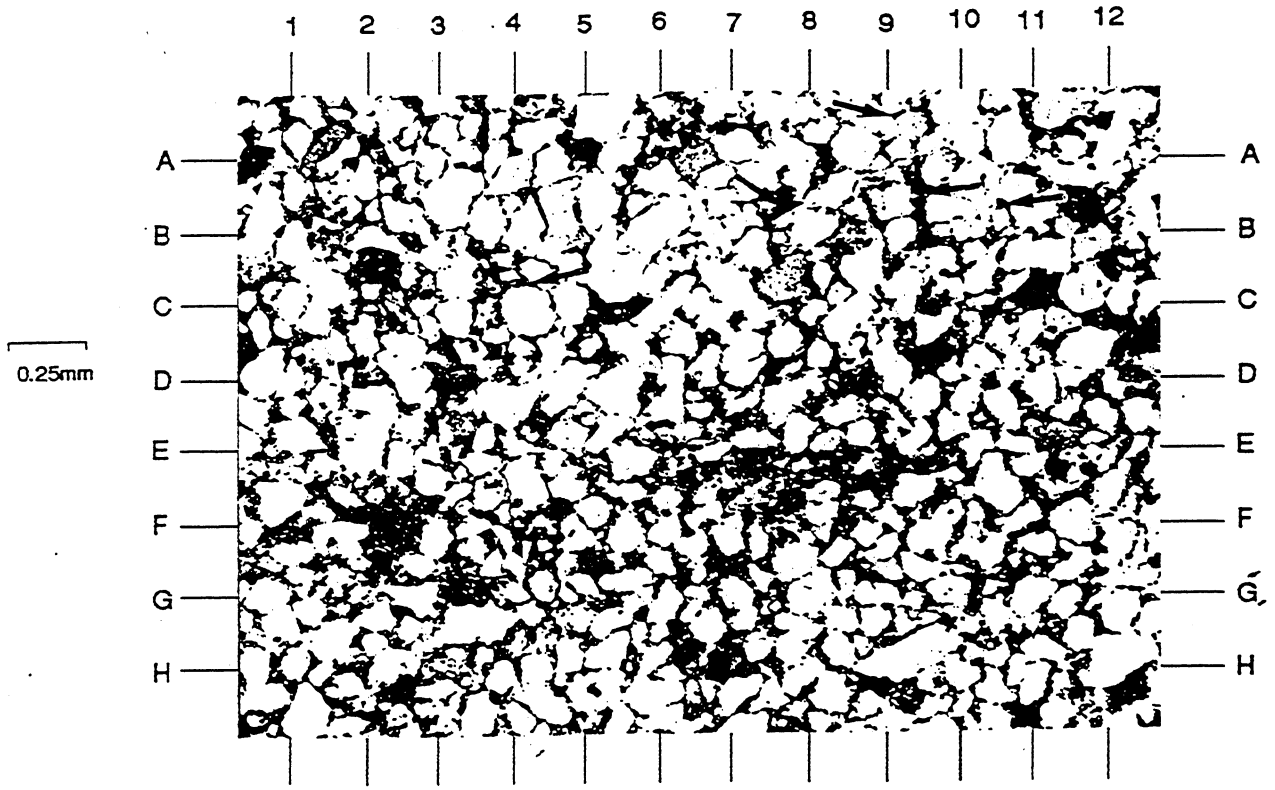
Plate 5A: 8014.4 Feet This low magnification thin section photomicrograph displays a very fine-grained sandstone. Light blue epoxy-filled intergranular pores (black arrows) are difficult to distinguish from abundant dark blue Fe-dolomite (white F's). (40X: Plane polarized light)

Plate 5B: 8014.4 Feet An enlarged view of the area near C10 in Plate 5A is displayed in this high magnification photomicrograph. Intergranular pores (black arrows) are uncommon. Pore-filling agents include reservoir bitumen (white B's), rhombic Fe-dolomite crystals (white arrows), and quartz cement (black q's). (160X: Plane polarized light)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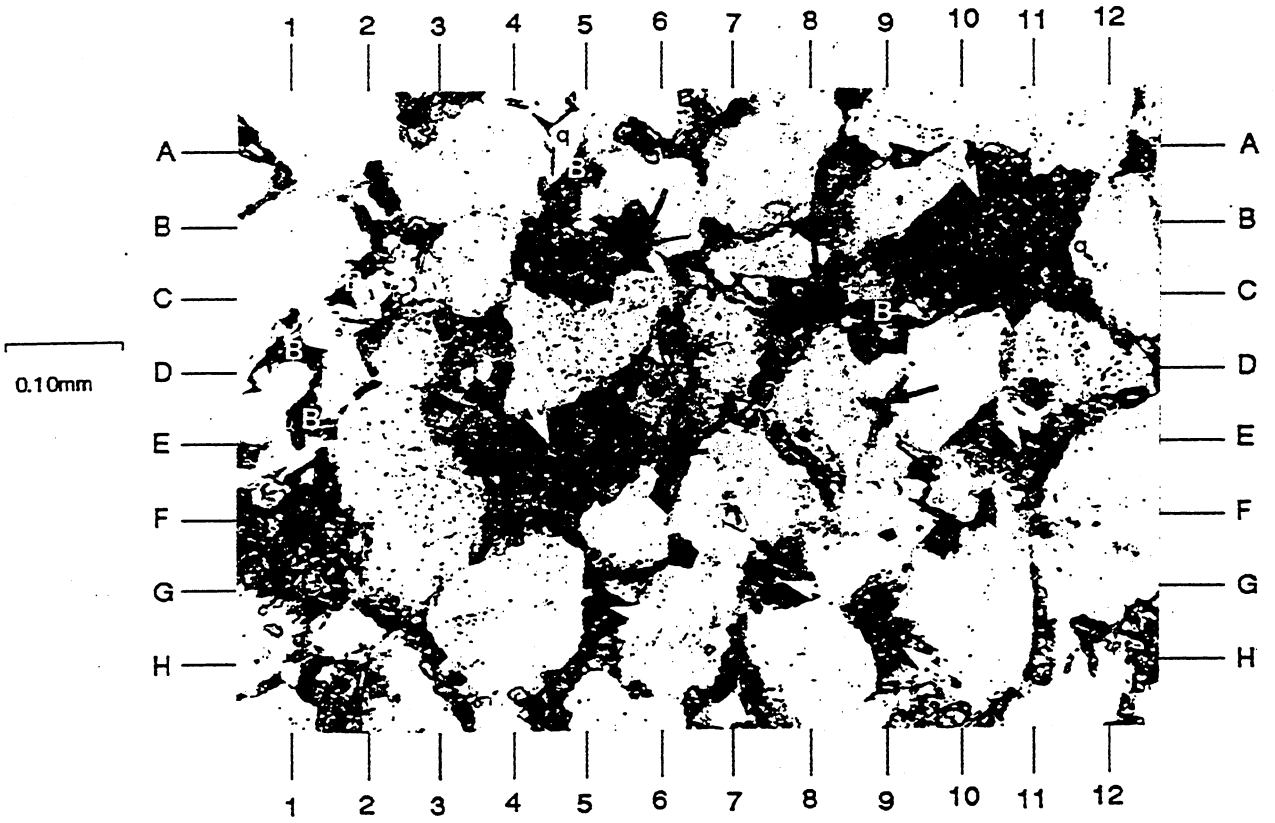
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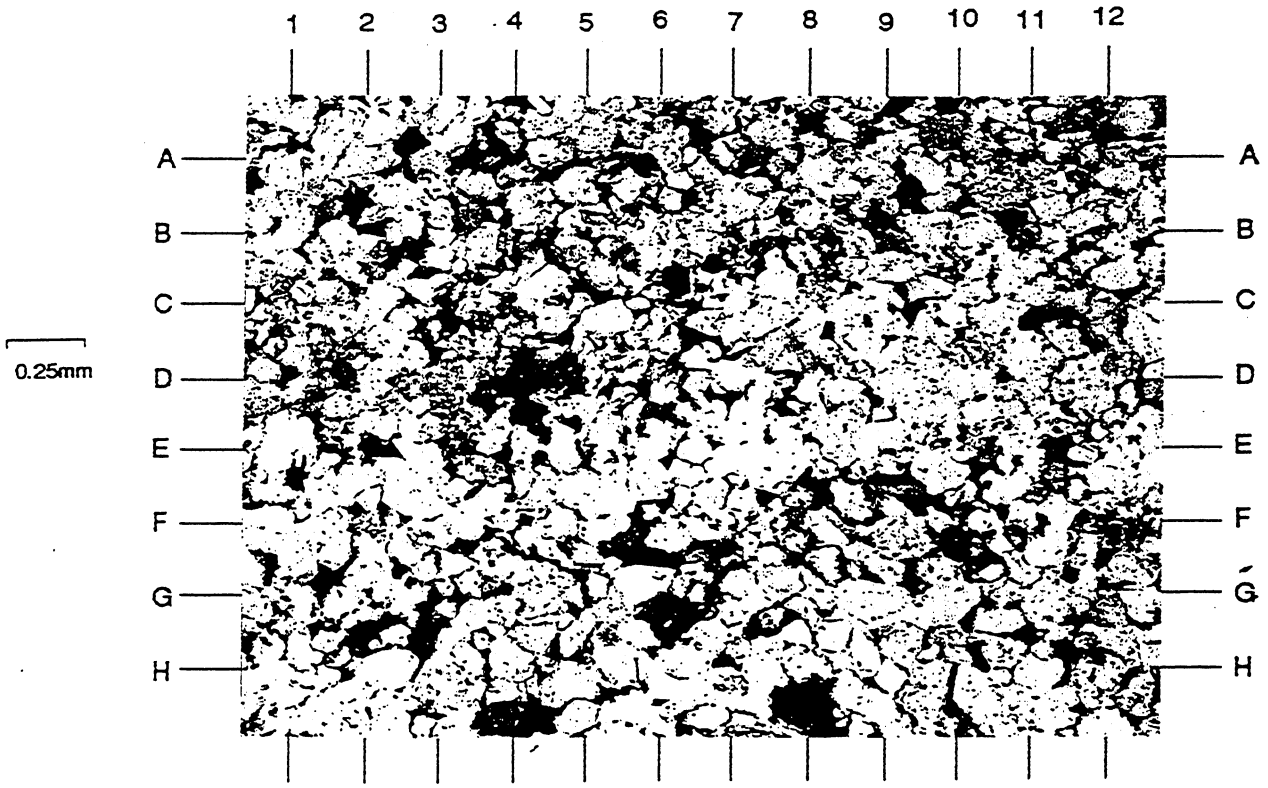
Plate 6A: 8017.3 Feet A faintly laminated fine-grained sandstone is displayed in this low magnification thin section photomicrograph. Visible pores (light blue epoxy) are common and evenly distributed. (40X: Plane polarized light)

Plate 6B: 8017.3 Feet An enlarged view of the area near B8 in Plate 6A is displayed in this high magnification photomicrograph. Intergranular pores (E2, A5, C8.5, F11, G6, F2) are common but reduced in size due to quartz overgrowths (black arrows). Note the secondary grain-moldic dissolution pores near B6 and C11.5. (160X: Plane polarized light)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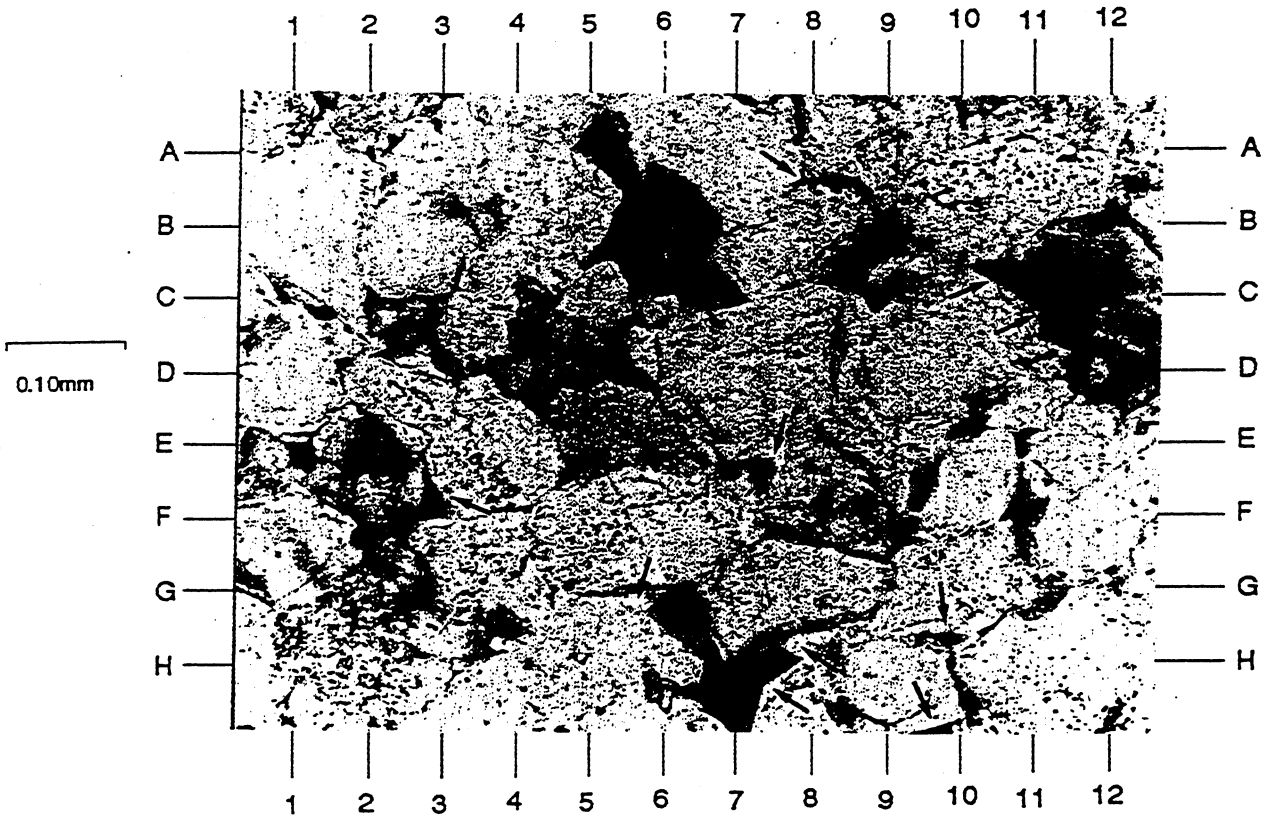
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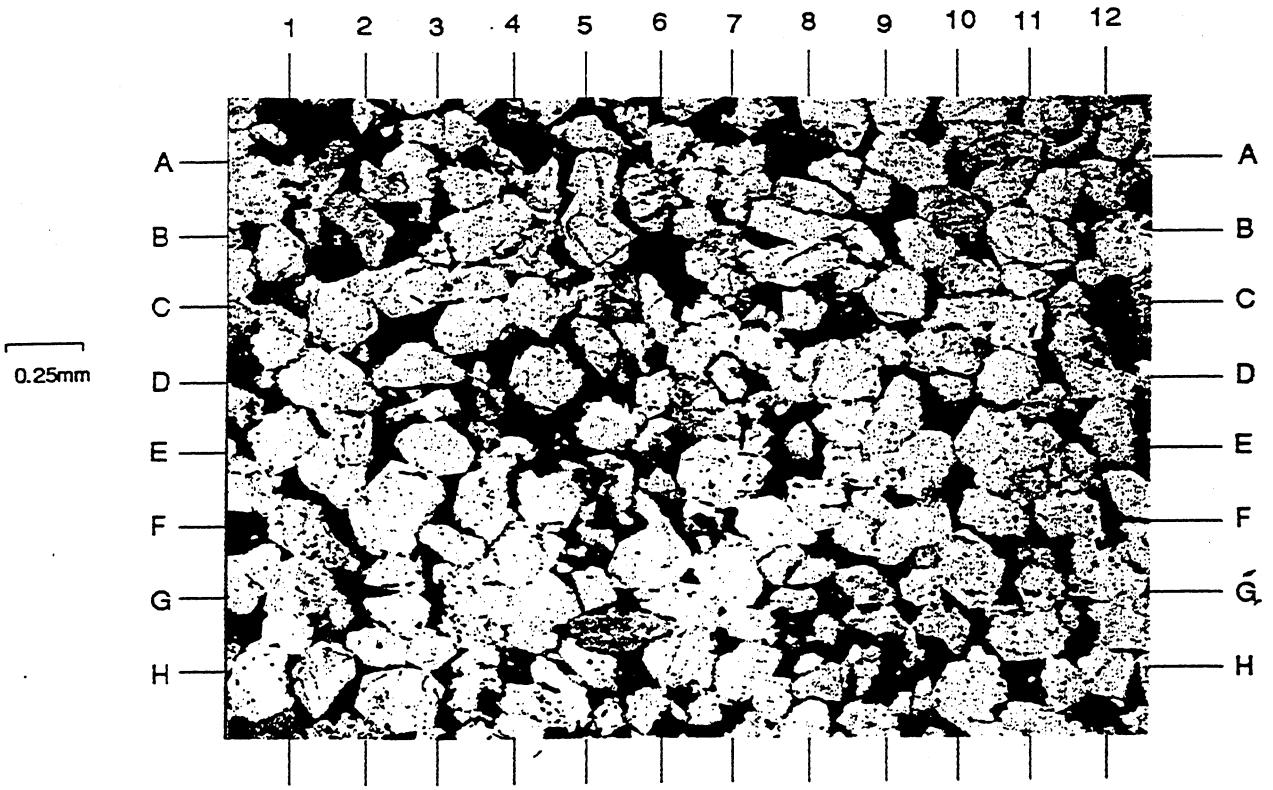
Plate 7A: 8020.8 Feet This low magnification thin section photomicrograph displays a massive, well sorted fine-grained sandstone. Visible pores (light blue epoxy) are common and relatively large in size. (40X: Plane polarized light)

Plate 7B: 8020.8 Feet An enlarged view of the area near D6 in Plate 7A is displayed in this high magnification photomicrograph. Pore-filling cements include quartz overgrowths (black arrows) and much less commonly Fe-dolomite (A9). Visible pores appear well interconnected near C1, H1, and F4. (160X: Plane polarized light)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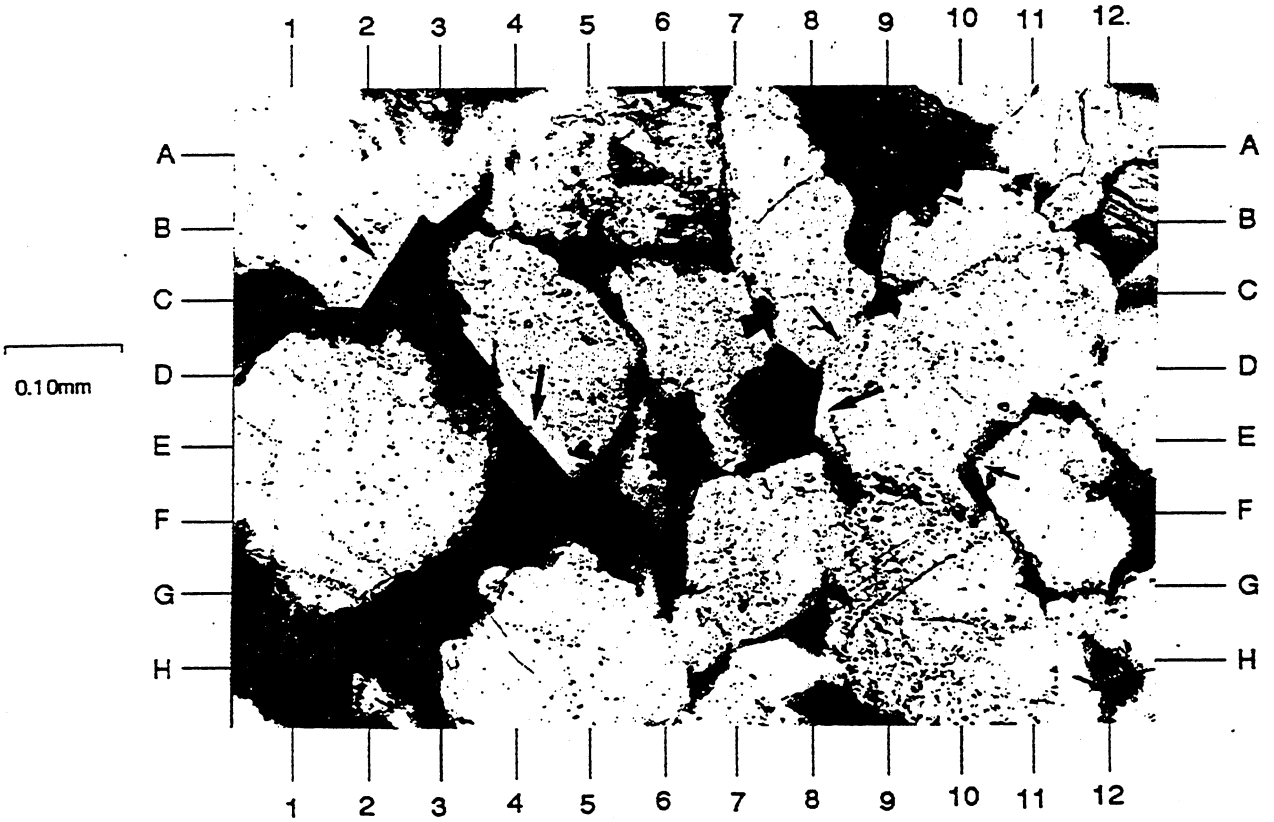
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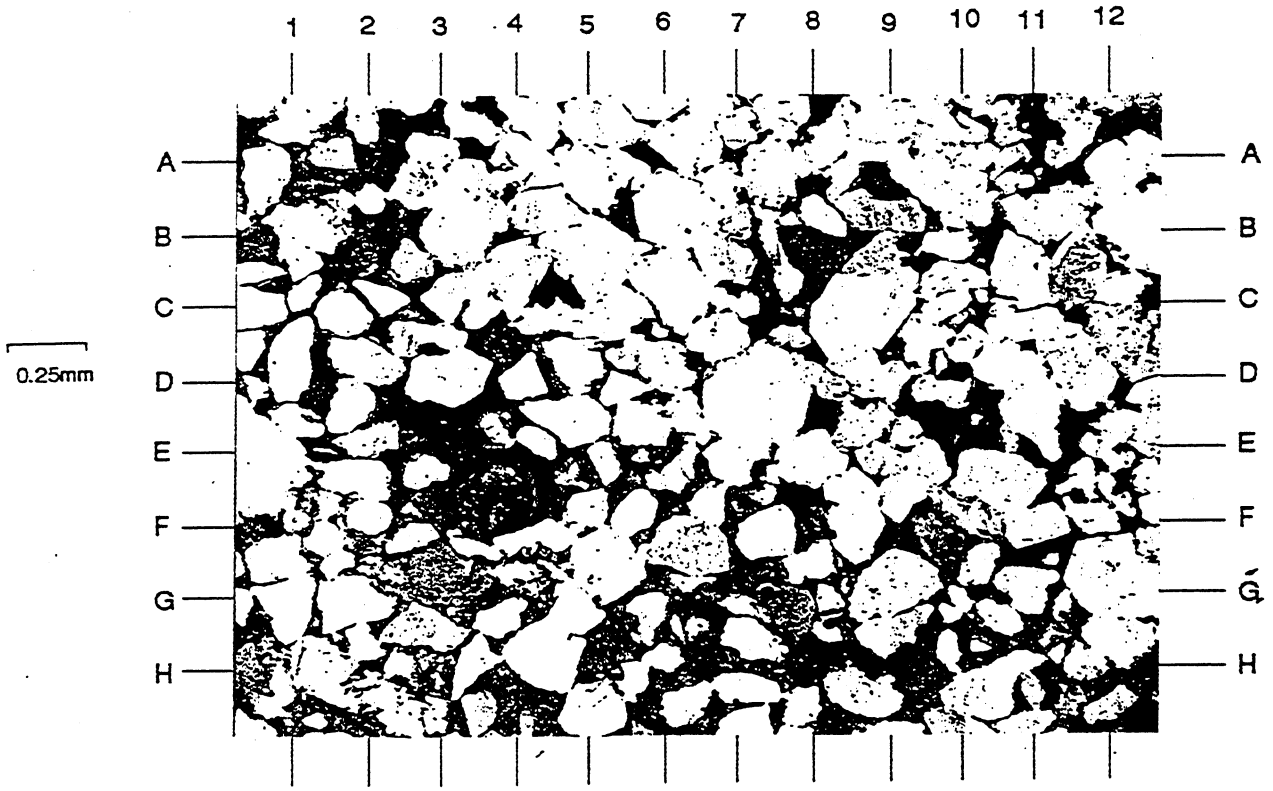
Plate 8A: 8021.3 Feet A massive well sorted fine-grained sandstone is displayed in this thin section photomicrograph. A large portion of the sample is tightly cemented by ferroan-calcite cement (purple stained - A2, E3, E5.5). Visible pores (light blue epoxy) are common within portions of the sample that lack ferroan calcite. (40X: Plane polarized light)

Plate 8B: 8021.3 Feet An enlarged view of the area near E6 in Plate 8A is displayed in this high magnification photomicrograph. This portion of the sample displays well developed quartz overgrowths (black arrows) and intergranular pores (D7, A11, H5). Note the ferroan-calcite cement near A1 and H2.5. (160X: Plane polarized light)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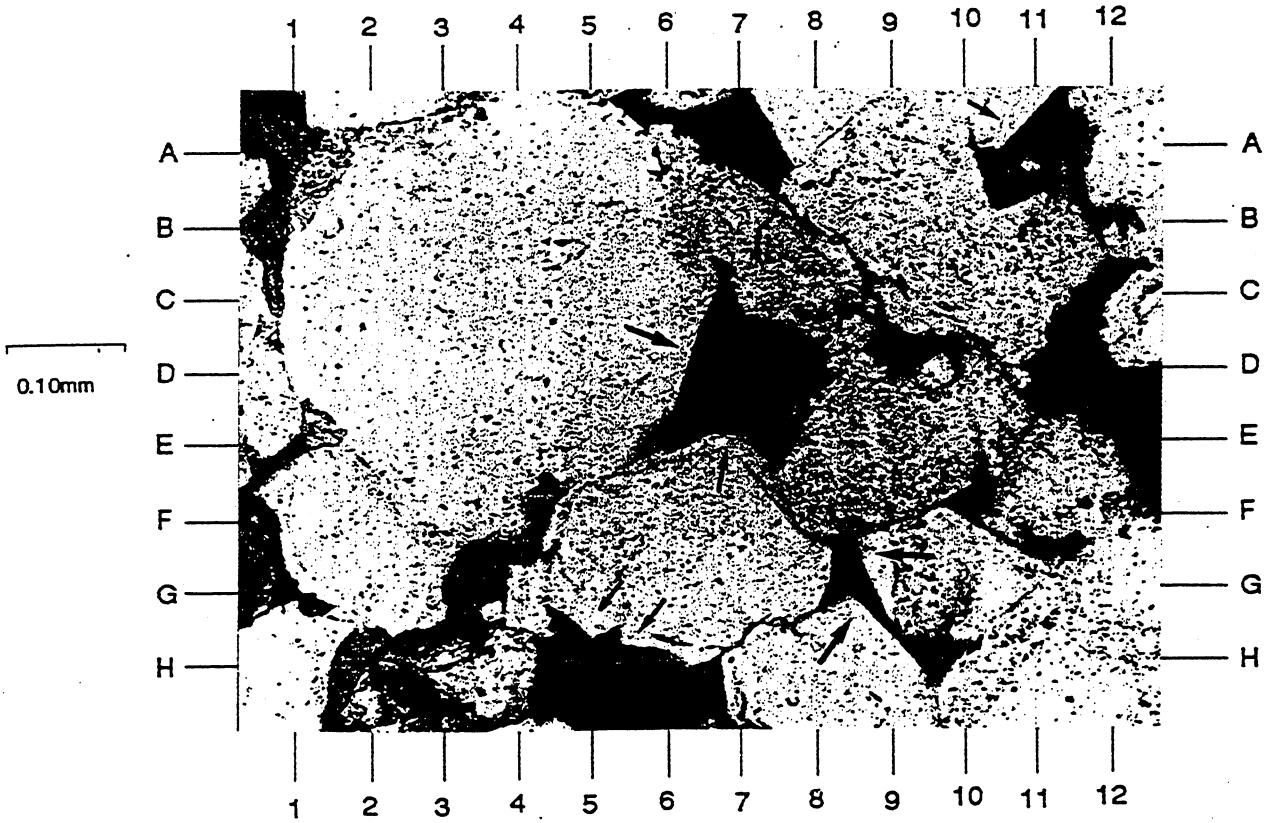
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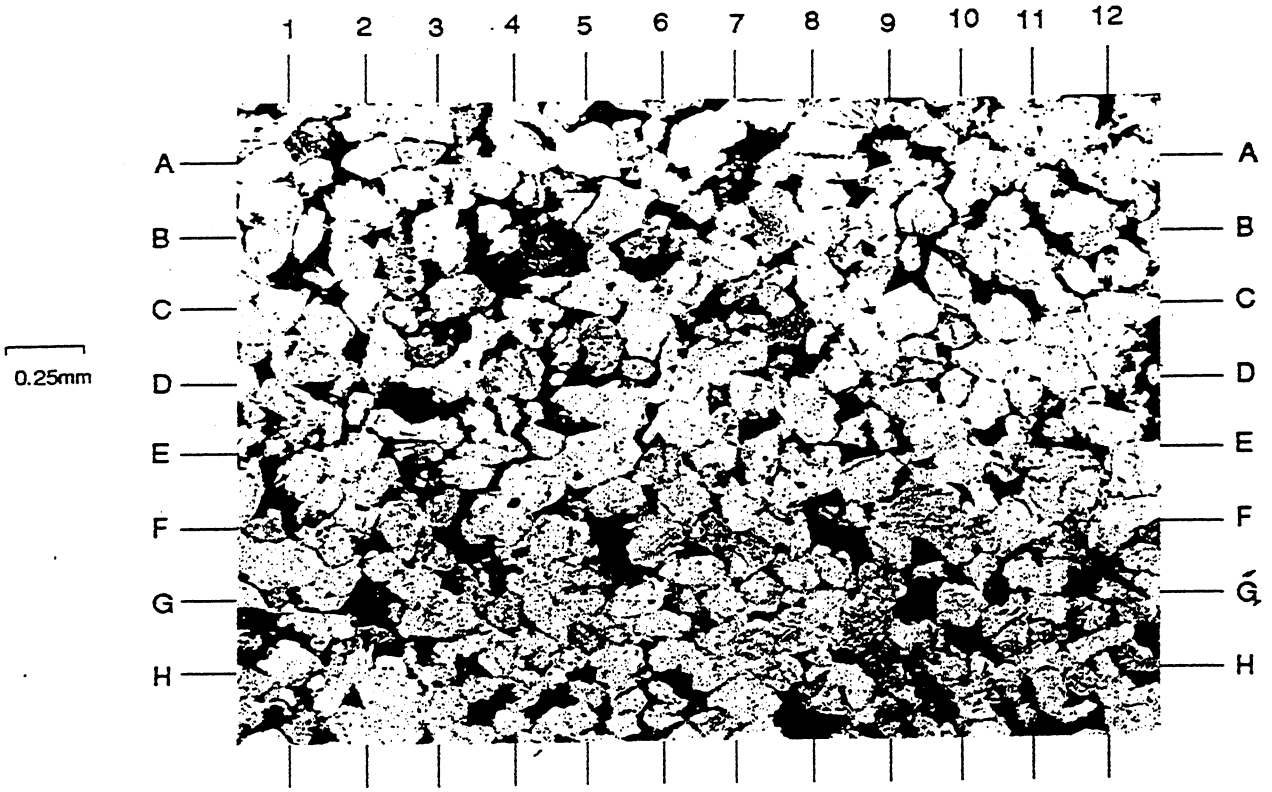
Plate 9A: 8028.4 Feet This low magnification thin section photomicrograph displays a massive well sorted fine-grained sandstone. Visible pores (light blue epoxy) are common and evenly distributed. (40X: Plane polarized light)

Plate 9B: 8028.4 Feet An enlarged view of the area near F7 in Plate 9A is displayed in this high magnification photomicrograph. Visible pores include intergranular pores (B5.5, D7, G4, G11) and grain-moldic dissolution pores (D11). (160X: Plane polarized light)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0.25mm

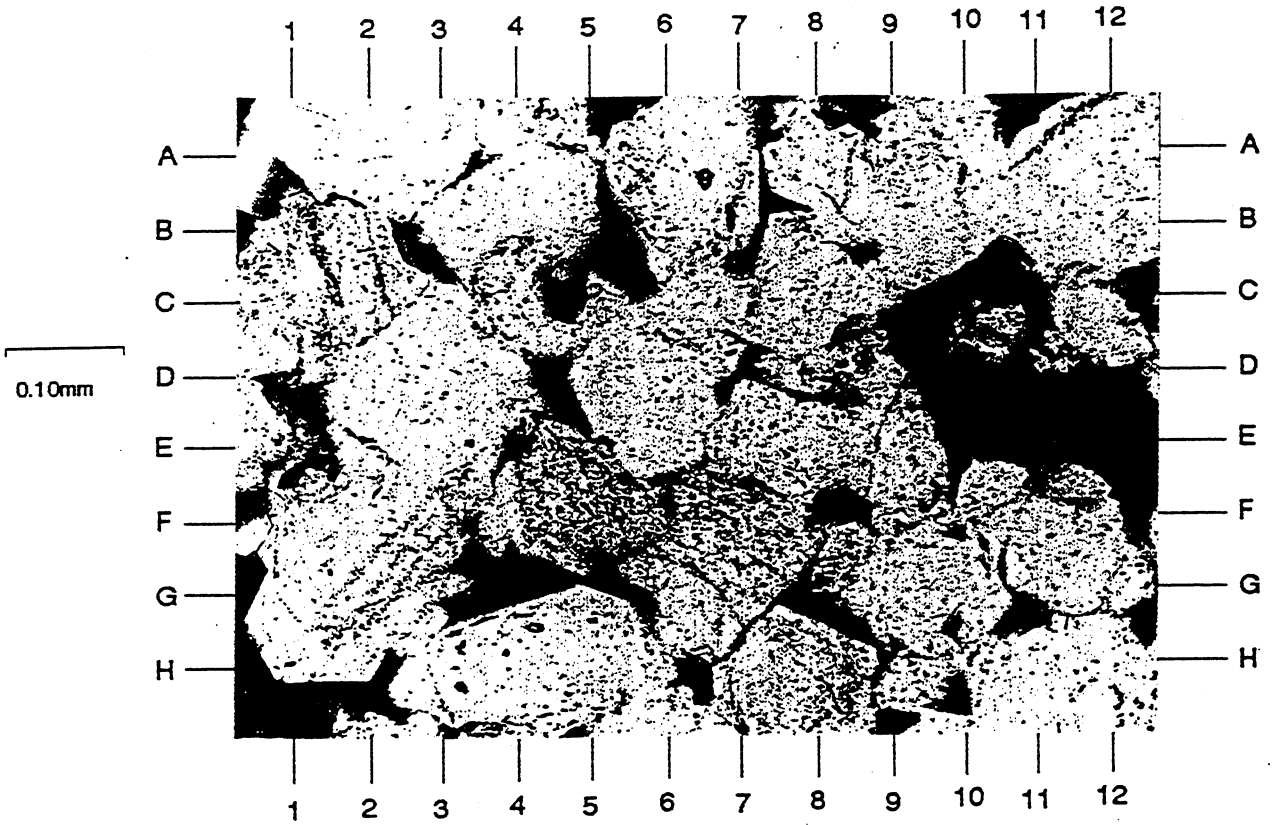
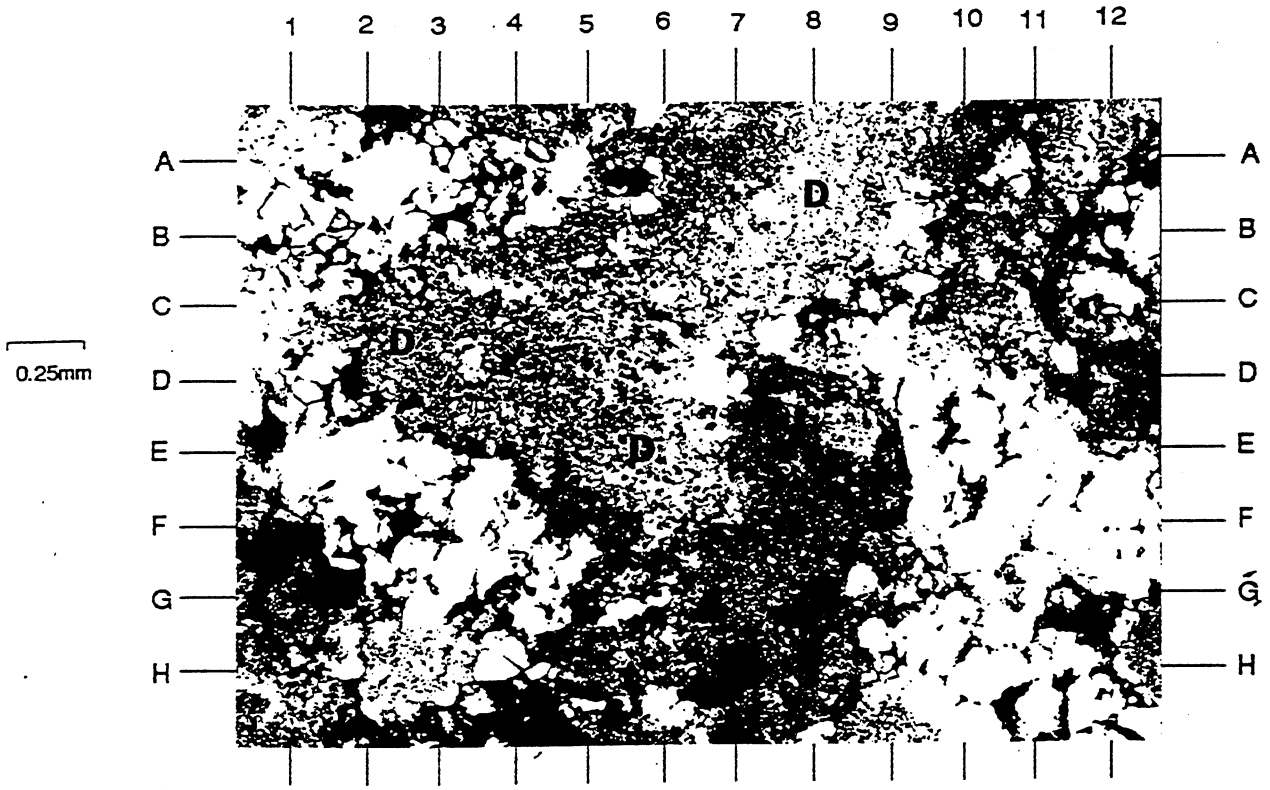

1 2 3 4 5 6 7 8 9 10 11 12
A
B
C
D
E
F
G
H
0.10mm

Plate 10A: 8031.2 Feet A bioturbated, silty shaley very fine-grained sandstone is displayed in this low magnification thin section photomicrograph. Detrital clays (D) are unevenly distributed. (40X: Plane polarized light)

Plate 10B: 8031.2 Feet An enlarged view of the area near D2 in Plate 10A is displayed in this high magnification photomicrograph. Detrital clay (light brown) appears common in the right half of the photomicrograph. Reservoir bitumen (dark brown) commonly occludes intergranular pores. (160X: Plane polarized light)


1 2 3 4 5 6 7 8 9 10 11 12
A B C D E F G H
D
D
D
0.25mm

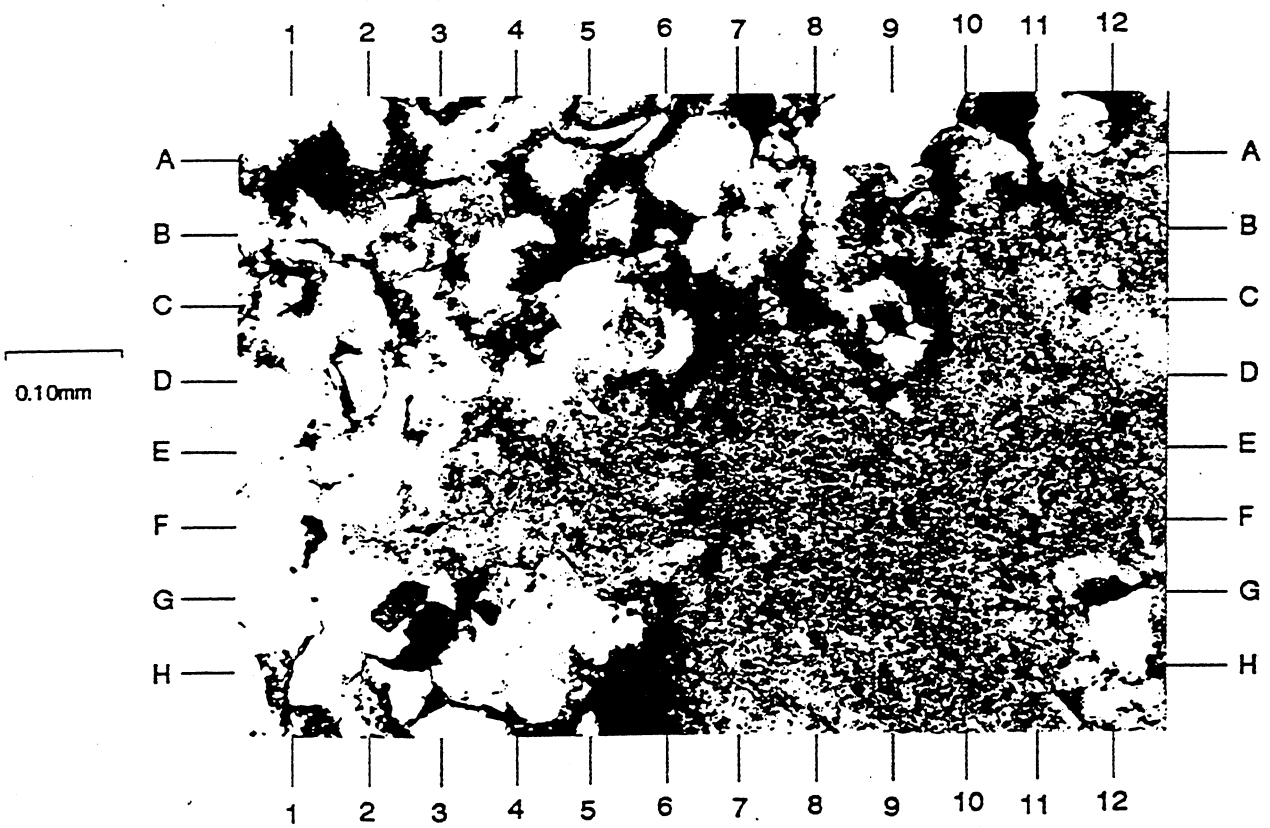
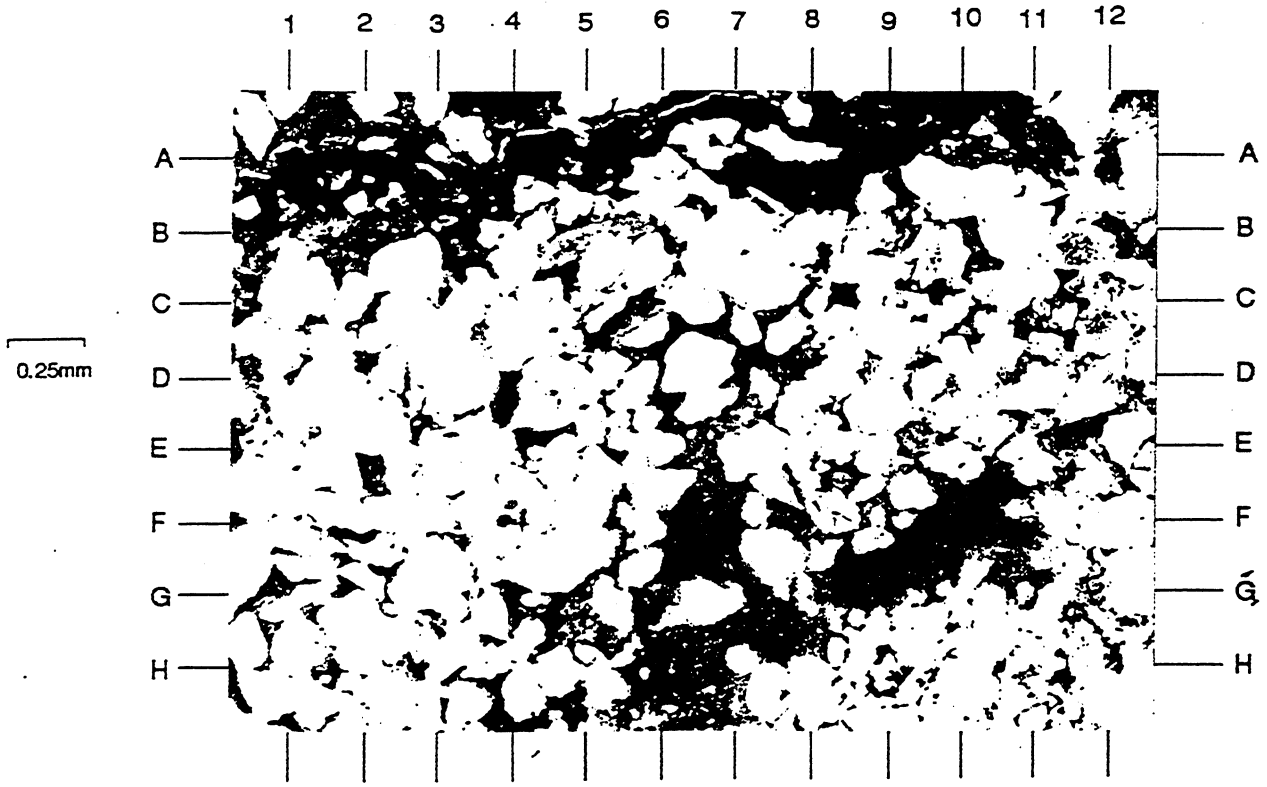

1 2 3 4 5 6 7 8 9 10 11 12
A B C D E F G H
0.10mm

Plate 11A: 8031.4 Feet This low magnification thin section photomicrograph displays a laminated fine-grained sandstone. Note the clay-rich lamination trending from A1-A15. Also note the clay rip-up clasts near F7 and F10. (40X: Plane polarized light)

Plate 11B: 8031.4 Feet An enlarged view of the area near E6.5 in Plate 11A is displayed in this high magnification photomicrograph. Pore-occluding agents include quartz cement (black arrows), ferroan calcite (B1.5, A6), pseudomatrix (D4), and detrital clay (G11). (160X: Plane polarized light)


1 2 3 4 5 6 7 8 9 10 11 12
A
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C
D
E
F
G
H
0.25mm

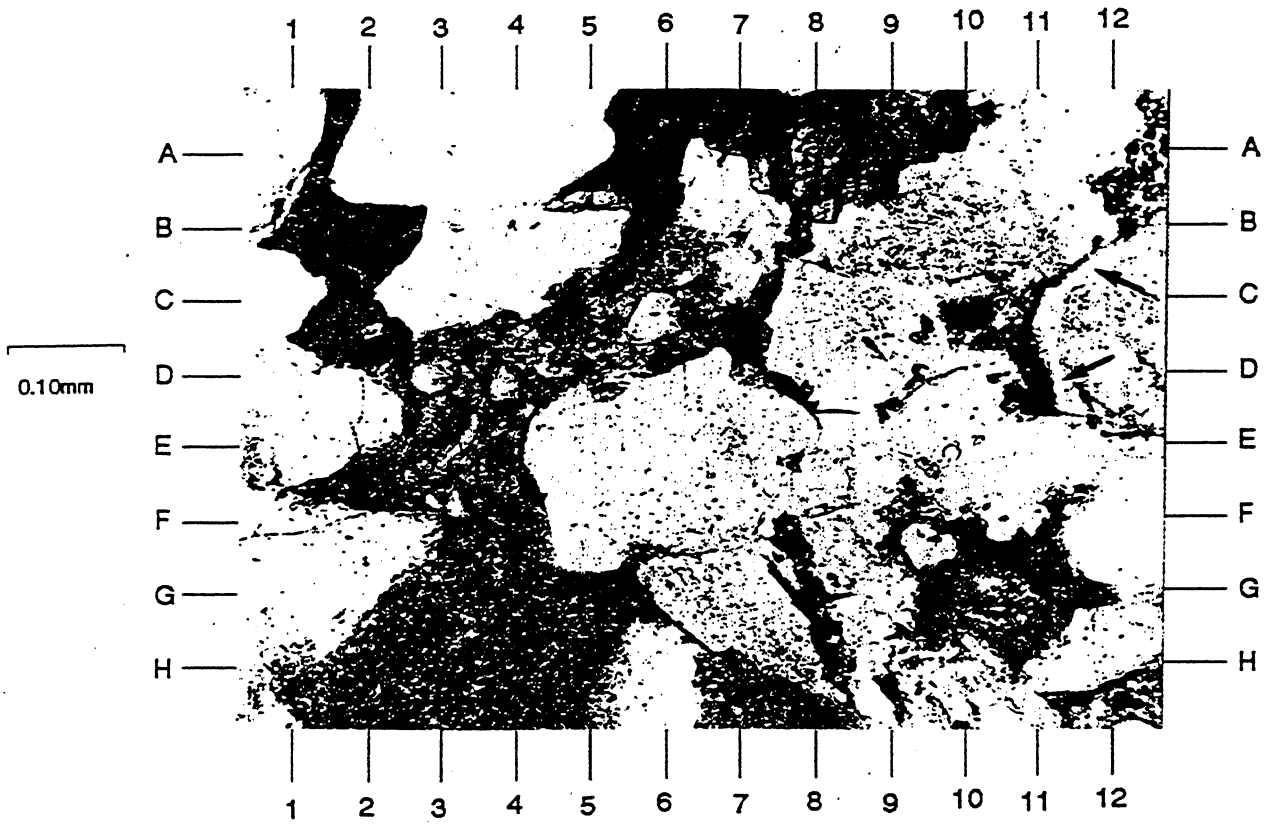
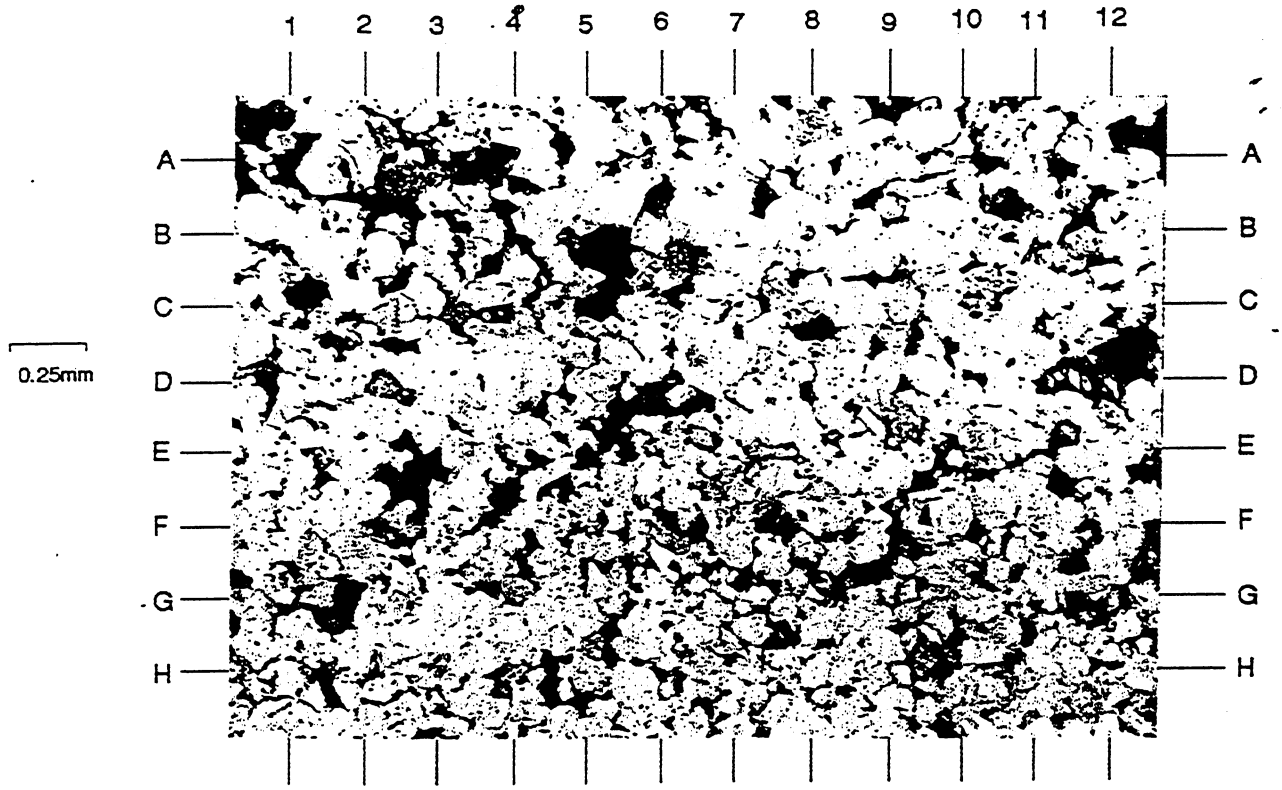
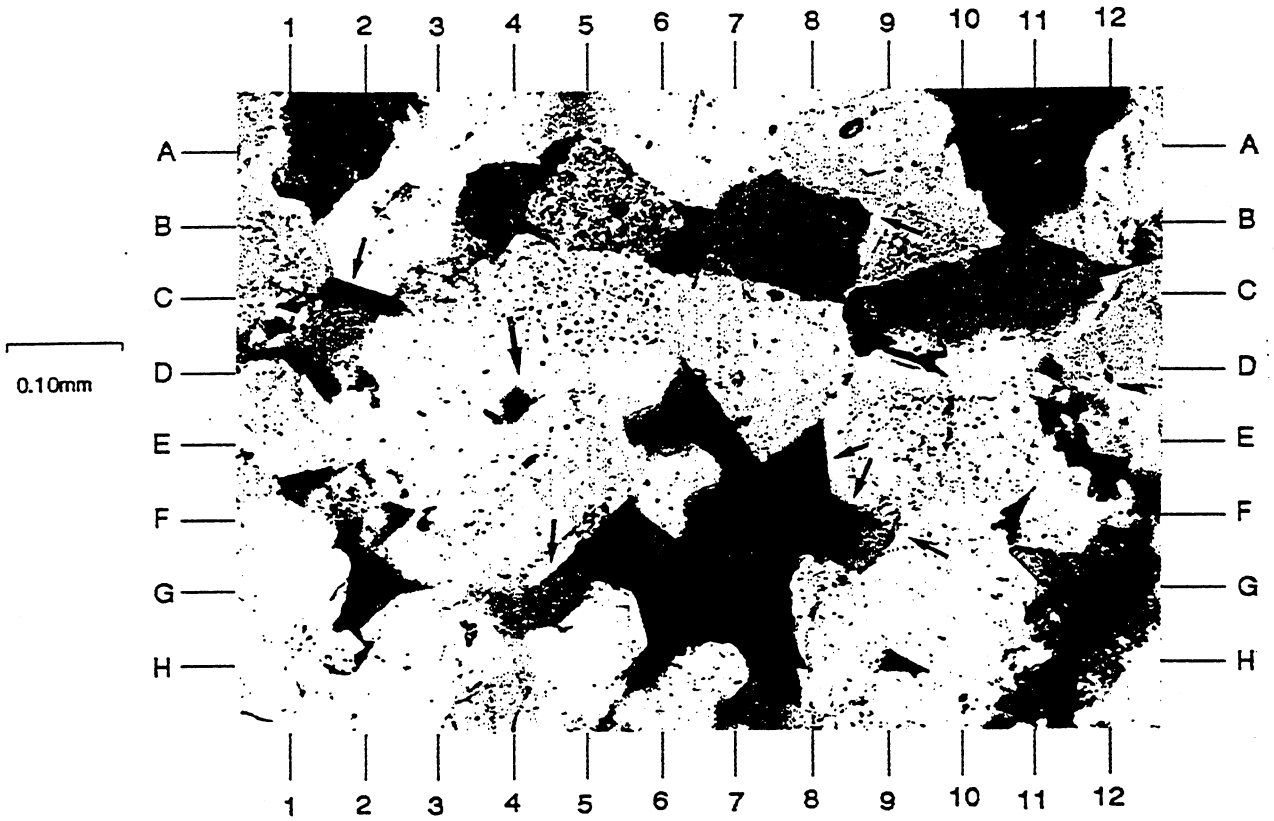
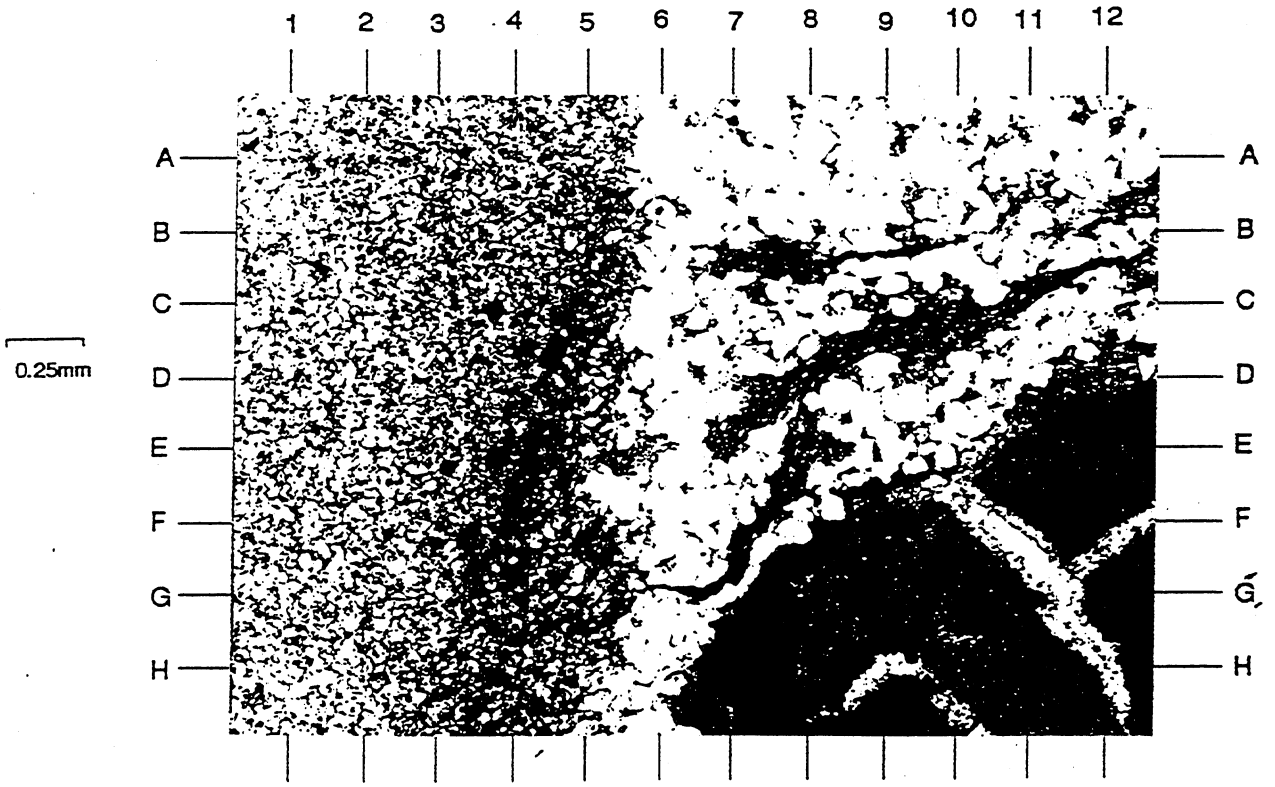

1 2 3 4 5 6 7 8 9 10 11 12
A
B
C
D
E
F
G
H
0.10mm

Plate 12A: 8032.5 Feet A massive well sorted fine-grained sandstone is displayed in this low magnification thin section photomicrograph. Although visible pores (light blue epoxy) are relatively small, they are common and evenly distributed. (40X: Plane polarized light)

Plate 12B: 8032.5 Feet An enlarged view of the area near E3 in Plate 12A is displayed in this high magnification photomicrograph. Visible pores include intergranular pores (C2, F2, A4.5, A10) and grain-moldic dissolution pores (G6.5). Many pores are lined with dark brown reservoir bitumen. Note the abundant quartz overgrowths (black arrows). (160X: Partially cross-polarized light)


1 2 3 4 5 6 7 8 9 10 11 12
A B C D E F G H
0.25mm


1 2 3 4 5 6 7 8 9 10 11 12
A B C D E F G H
0.10mm


1 2 3 4 5 6 7 8 9 10 11 12
A B C D E F G H
0.25mm

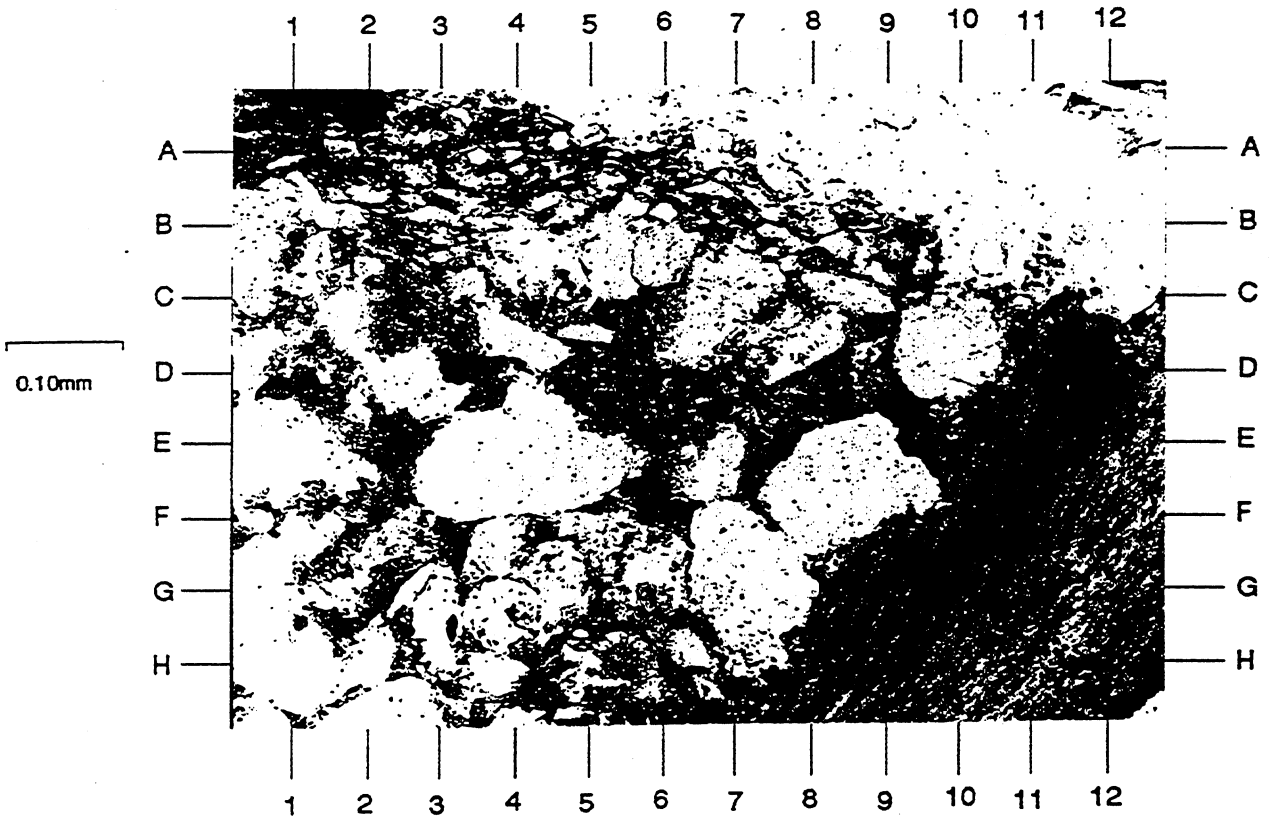
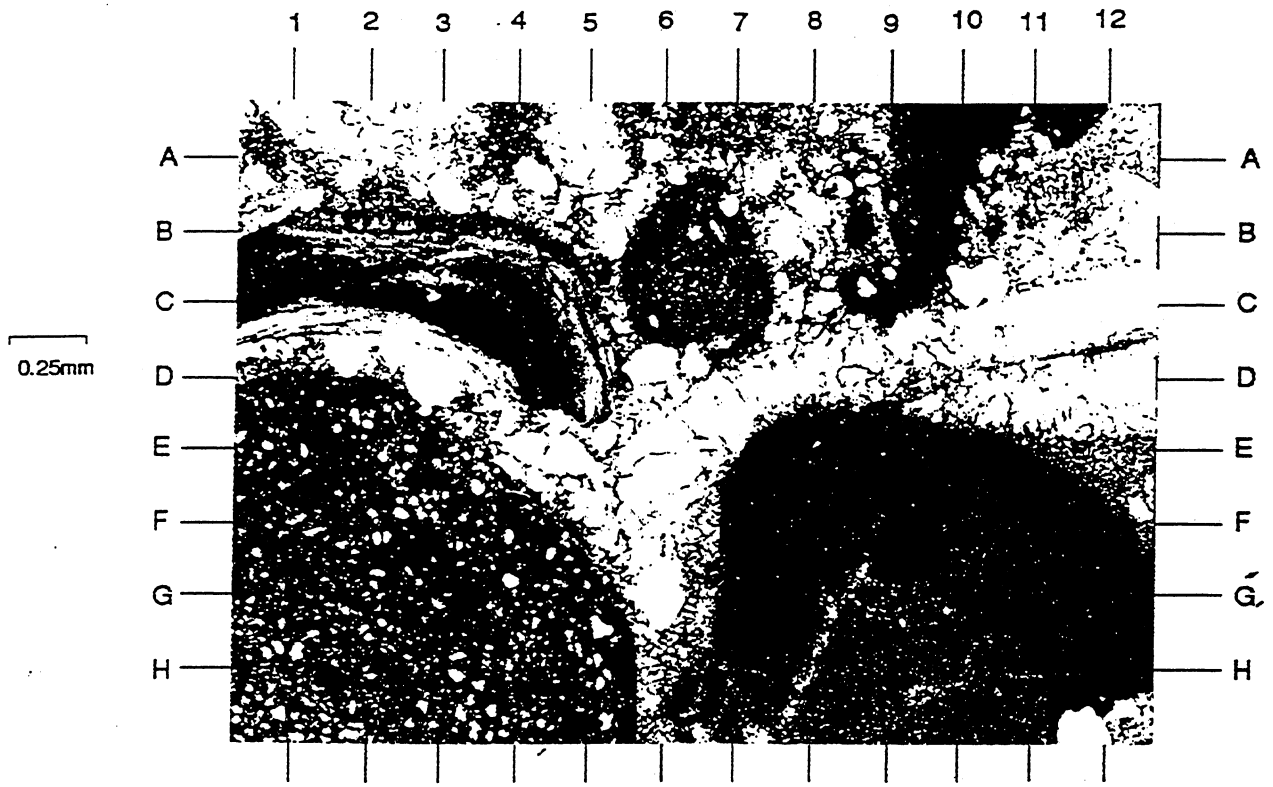

1 2 3 4 5 6 7 8 9 10 11 12
A B C D E F G H
0.10mm

Plate 14A: 8033.9 Feet A sandy limestone conglomerate is displayed in this low magnification thin section photomicrograph. Granule- to pebble-sized grains include limestone clasts (G2, B6.5, G10) and calcareous pelecypod shell fragments (B3, D7-C15). (40X: Plane polarized light)

Plate 14B: 8033.9 Feet An enlarged view of the area near E7 in Plate 14A is displayed in this high magnification photomicrograph. Calcite cement is pervasive between framework grains (C7, H7, E3). (160X: Plane polarized light)


1 2 3 4 5 6 7 8 9 10 11 12
A
B
C
D
E
F
G
H
0.25mm

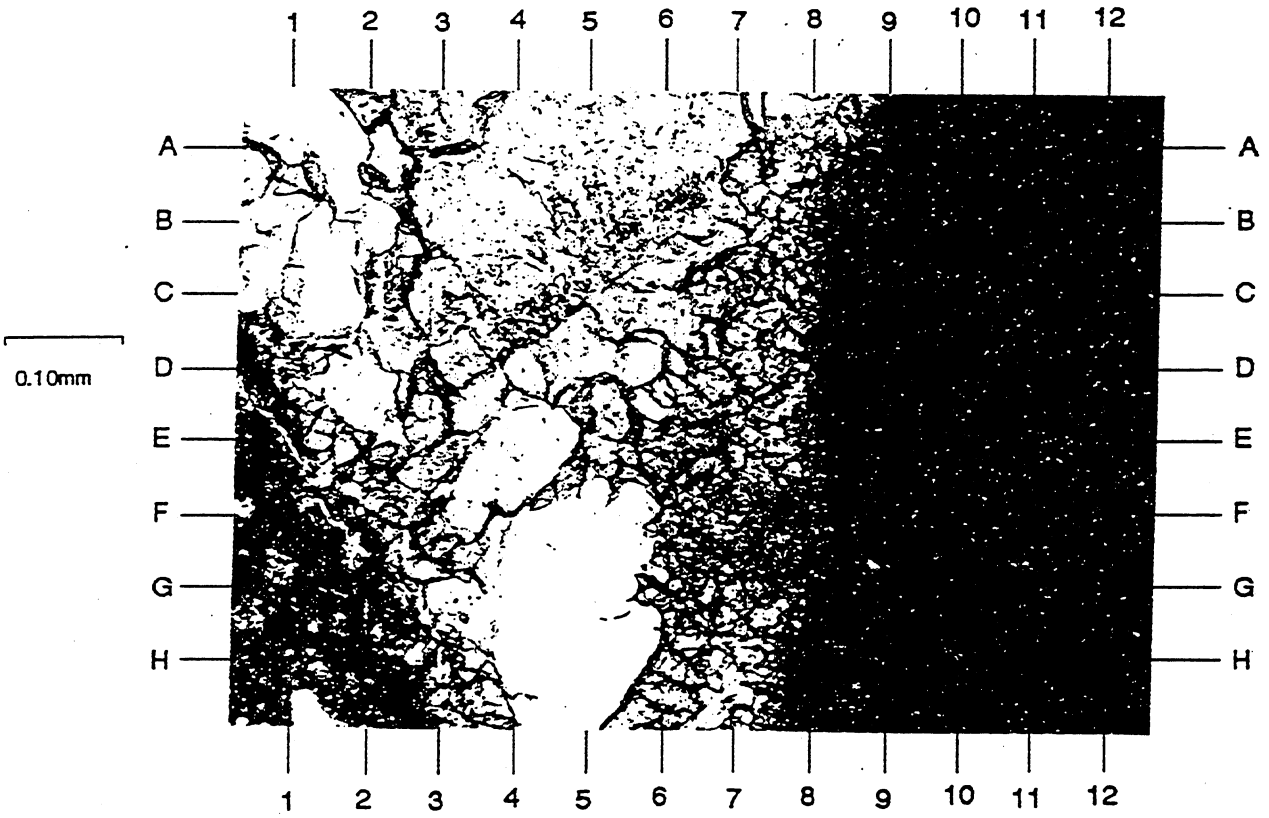
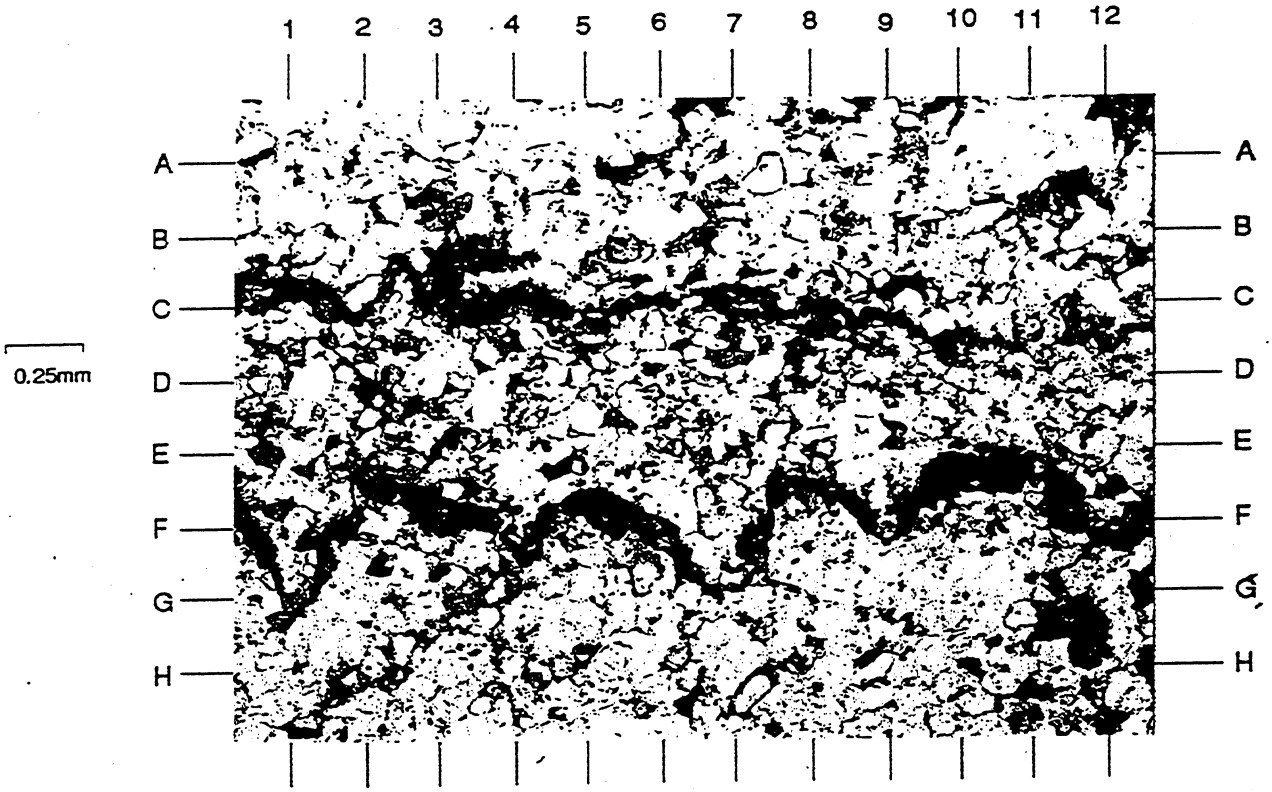
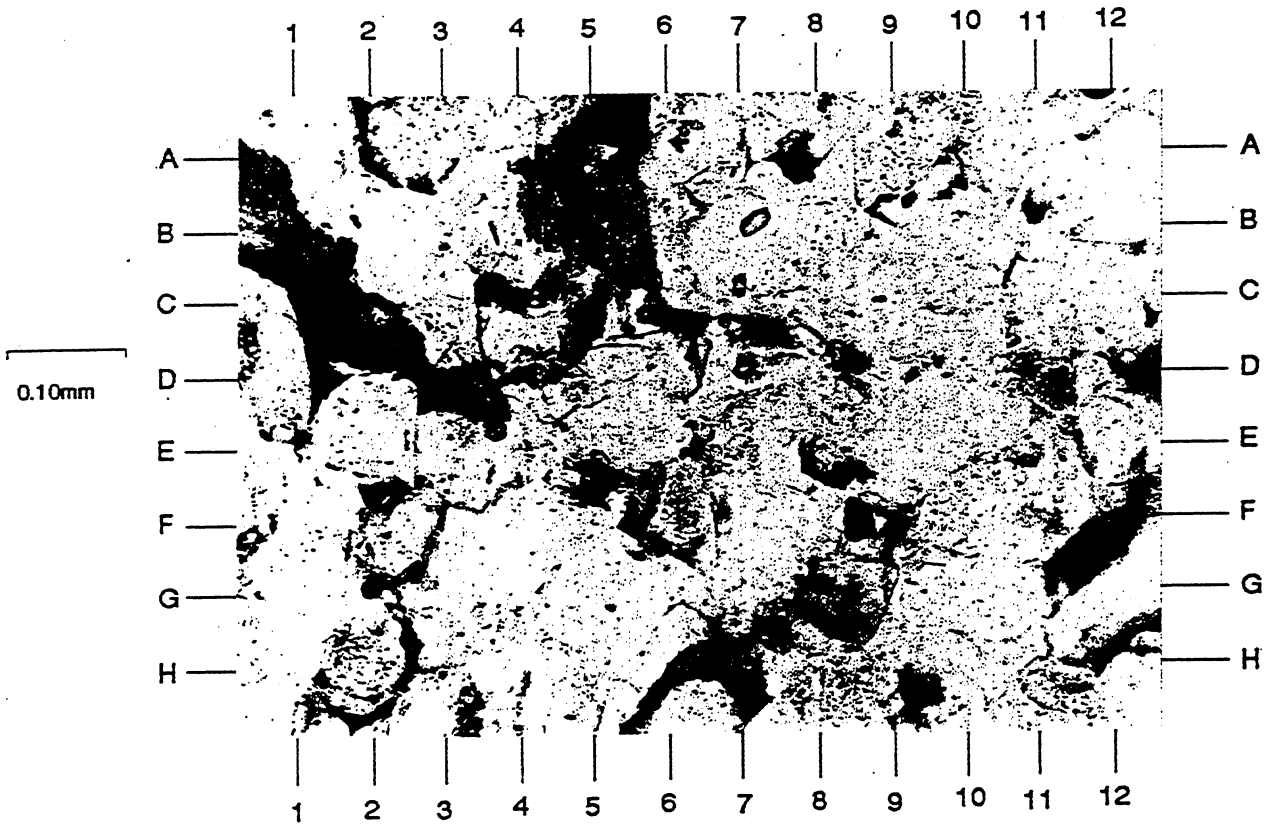

1 2 3 4 5 6 7 8 9 10 11 12
A
B
C
D
E
F
G
H
0.10mm

Plate 15A: 8035.3 Feet This low magnification thin section photomicrograph displays a well sorted very fine-grained sandstone. Note the wavy stylolites trending from C1-C15 and F1-F15. (40X: Plane polarized light)

Plate 15B: 8035.3 Feet An enlarged view of the area near H8 in Plate 15A is displayed in this high magnification photomicrograph. A portion of a stylolite near C1.5 displays detrital clay and reservoir bitumen. Intergranular pores (light blue epoxy) are relatively small and uncommon. (160X: Plane polarized light)


1 2 3 4 5 6 7 8 9 10 11 12
A
B
C
D
E
F
G
H
0.25mm


1 2 3 4 5 6 7 8 9 10 11 12
A
B
C
D
E
F
G
H
0.10mm

Texaco

DATE: October 10, 1991

HORIZONTAL WELLS PLANNED FOR NORTH-EAST TEXAS IN THE NEW HOPE FIELD, OF FRANKLIN COUNTY, TEXAS

Texaco is currently drilling the first horizontal well in north-eastern Texas, and the second well will immediately follow. The two horizontal wells, one producer and one injector, will be completed this year in the New Hope Field which is located in Franklin county, Texas. The wells are the focal point of a waterflood expansion project in the Pittsburg 'C' reservoir.

The first is a horizontal oil production well with a planned horizontal displacement of 2000 feet. The second well will be a water injection well with a 1500 foot displacement planned. The Texas Railroad Commission has reported this to be the first water injection application received for a horizontal well.

By drilling these two horizontal wells, Texaco is attempting to instill new development life into a reservoir which has been producing for over 45 years, and was previously thought to be nearly depleted. Additional applications of horizontal technology in this reservoir are being evaluated, and will proceed pending the degree of success with the current phase of horizontal drilling.

The Texaco New Hope Development Team, a cross-discipline team of engineers, geologists, operations staff, and research scientists, evaluated and is implementing the project. The Team's focus in developing a horizontal waterflood expansion was:

- to apply horizontal wells as a reservoir management tool to significantly increase oil recovery in this mature waterflood.
- to develop means to increase oil production rates and water injection rates in low permeability, sandstone reservoirs.
- to apply horizontal drilling experience Texaco has gained by drilling the Austin Chalk trend, to this hard rock, thin sandstone reservoir located at a depth of 8000'.
- to improve development economics by; increasing oil production and water injection rates; drilling 2 horizontal wells instead of 5 or 6 vertical wells; and reducing the number of wells to be operated in the field.

Through the application of this horizontal drilling project at New Hope, Texaco hopes to better understand and apply this technology in maximizing oil and gas recovery from other sandstone reservoirs and enhanced oil recovery projects. In short, Texaco is striving to use horizontal drilling technology as a tool to improve reservoir management techniques and maximize the value of its assets.

TRK

PORT NECHES FIELD CO_2 MISCIBLE FLOOD

ORANGE COUNTY, TEXAS

CO_2 PROJECT DESIGN

PORT NECHES FIELD CO2 MISCIBLE FLOOD
ORANGE COUNTY, TEXAS

CO2 PROJECT DESIGN

PREPARED BY DARRELL W. DAVIS
NOVEMBER, 1991

HARVEY, LOUISIANA

INTRODUCTION

A CO_2 miscible flood is recommended for the Marginulina sandstone reservoir at the Port Neches Field in Orange County, Texas. Project design indicates that an additional 19% of original oil in place, or 2.2 MMBO, can be recovered over current waterflood operations. This study has concluded that two separate fault blocks exist in this reservoir which are attractive for CO_2 flooding technology. The largest, 240 acre fault block, lies on the W. H. Stark -B-, H. J. Kuhn Tracts 1 and 2, and J. V. Polk -B- leases. It has produced 5.7 MMBO out of 10.0 MMBO, for a recovery of 57% of original oil-in-place (OOIP), and has an average oil saturation of 32%. The other 30 acre fault block lies on the J. V. Polk -B- lease and has recovered 0.6 MMBO out of 1.4 MMBO, for a recovery of 43% OOIP, and has an average oil saturation of 42%. Oil in place figures were determined by volumetric calculations, as well as, material balance analysis using reservoir pressure data.

The Port Neches Field Marginulina reservoir was discovered during August, 1934 by the completion of the J. V. Polk -B- Well No. 2. In January, 1935, the H. J. Kuhn Tract 2 Well No. 6 was completed in this same reservoir, and these two wells produced at high rates with reservoir pressure dropping below the bubble point of 2550 psi early in the life of the reservoir. As a result of this, reservoir pressures dropped rapidly, and by 1965, the bottomhole pressure of the reservoir was only 100 psi. It was at this time, in 1965, that a waterflood was initiated on the W. H. Stark -B- and H. J. Kuhn Tract 1 leases to improve oil recoveries.

Remaining secondary (waterflood) reserves for this large fault block are estimated at approximately 200,000 barrels, indicating that abandonment of the reservoir is eminent, if enhanced oil recovery procedures are not utilized. Daily production from this fault block averages 41 BOPD and 1047 BWPD. A water injection volume of 1300 BWPD is currently being injected into the reservoir.

An isolated fault block exists in this Marginulina reservoir which has been produced by one well, the J. V. Polk -B- Well No. 5. Historical reservoir pressures for fault blocks I, II, IV, and V, as identified in a January, 1954 study, indicate that fault blocks I, II, and IV are communicated and fault block V (Polk -B- No. 5), is separated. A material balance analysis of this well's production and reservoir pressure over time, indicates an original oil-in-place of approximately 1.4 MMBO. With 0.6 MMBO having been produced, 0.8 MMBO remains which can be targeted by CO2 injection. CO2 oil recovery results from this fault block which has had a partial waterdrive and a higher average oil saturation, can be compared to that of a fault block which has had a mature waterflood. Current production from the J. V. Polk -B- No. 5 is 8 BOPD and 59 BWPD.

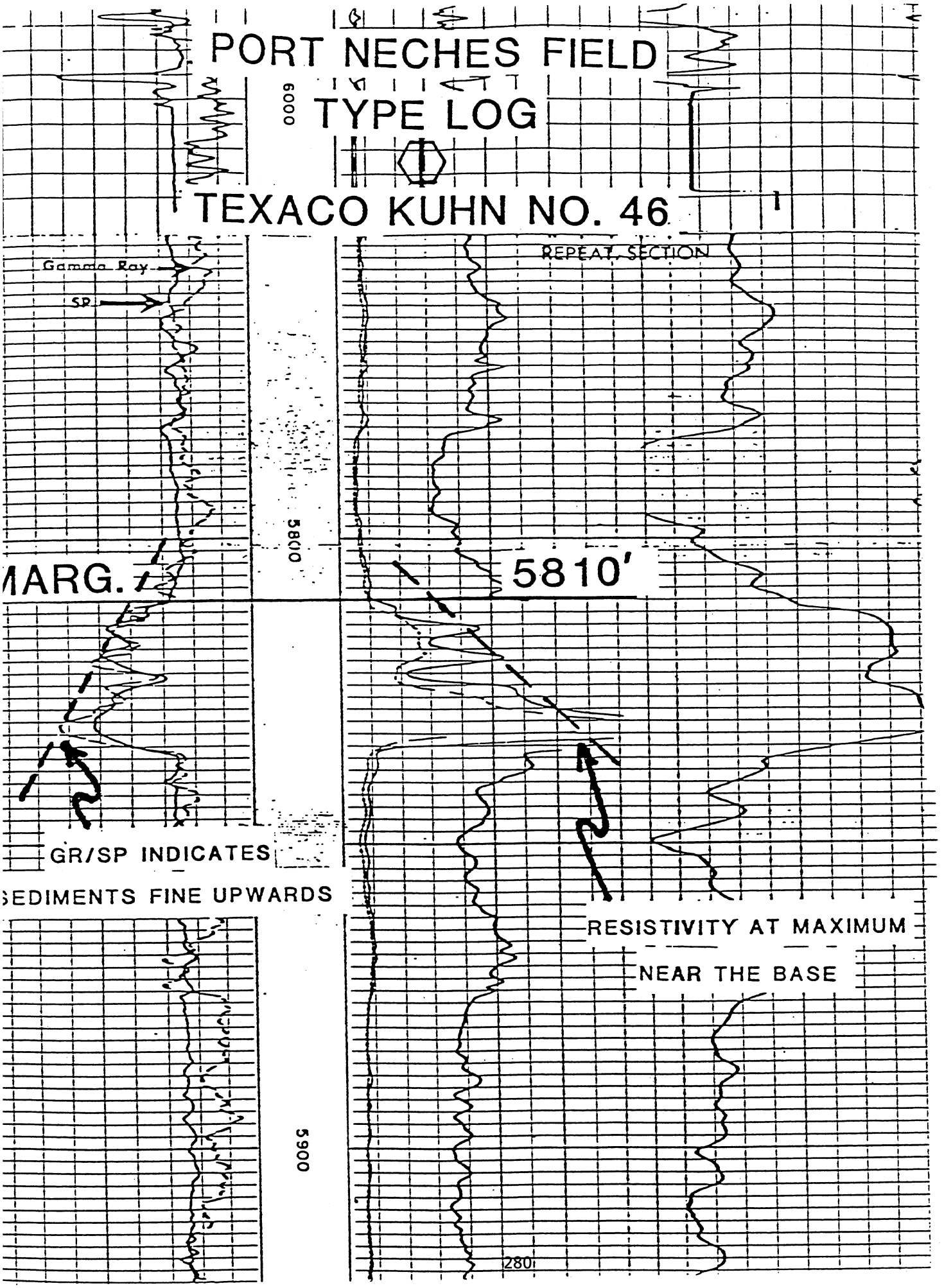
The Port Neches Field is an attractive CO2 candidate due to nearby CO2 sources. One CO2 supplier can deliver 4.3 MMCFPD of CO2 through their existing pipeline, requiring that Texaco lay only 4.5 miles of 4" line. In-house CO2 supplies also exist at Texaco Chemical's ethylene oxide plant 4 miles from the field, however preliminary economics indicate that this source may be cost

prohibitive at this time. Economic comparisons of the two potential sources have been performed utilizing Texaco's modified version of the DOE CO2PM program and Scientific Software Intercomp Incorporated's COMP III compositional model.

The following pages describe the process use in CO2 project design and results obtained.

LOG AND CORE POROSITY / PERMEABILITY

Attached is a type log of the H. J. Kuhn Tr. 1 No. 46. This log indicates the fining upward sequence common to fluvial dominated deltaic reservoirs. Also attached are sidewall core data for the W. H. Stark -B- Well No. 35 indicating the porosity and permeability variations seen in the Marginulina reservoir. An average porosity of 30% and horizontal permeability of 750 md was used in a compositional model for the reservoir. Refinement of this reservoir characterization is being made to account for this fining upward sequence profile. Sensitivities to reservoir heterogeneity will be made to determine its effect upon forecasted production schedules.


PORT NECHES FIELD
TYPE LOG
TEXACO KUHN NO. 46
6000
Gamma Ray
SP
REPEAT SECTION
5800
MARG.
5810'
GR/SP INDICATES
SEDIMENTS FINE UPWARDS
RESISTIVITY AT MAXIMUM
NEAR THE BASE
5900

FINAL REPORT

Sour Lake

CORE LABORATORIES, INC. CORE LAB *Petroleum Reservoir Engineering*

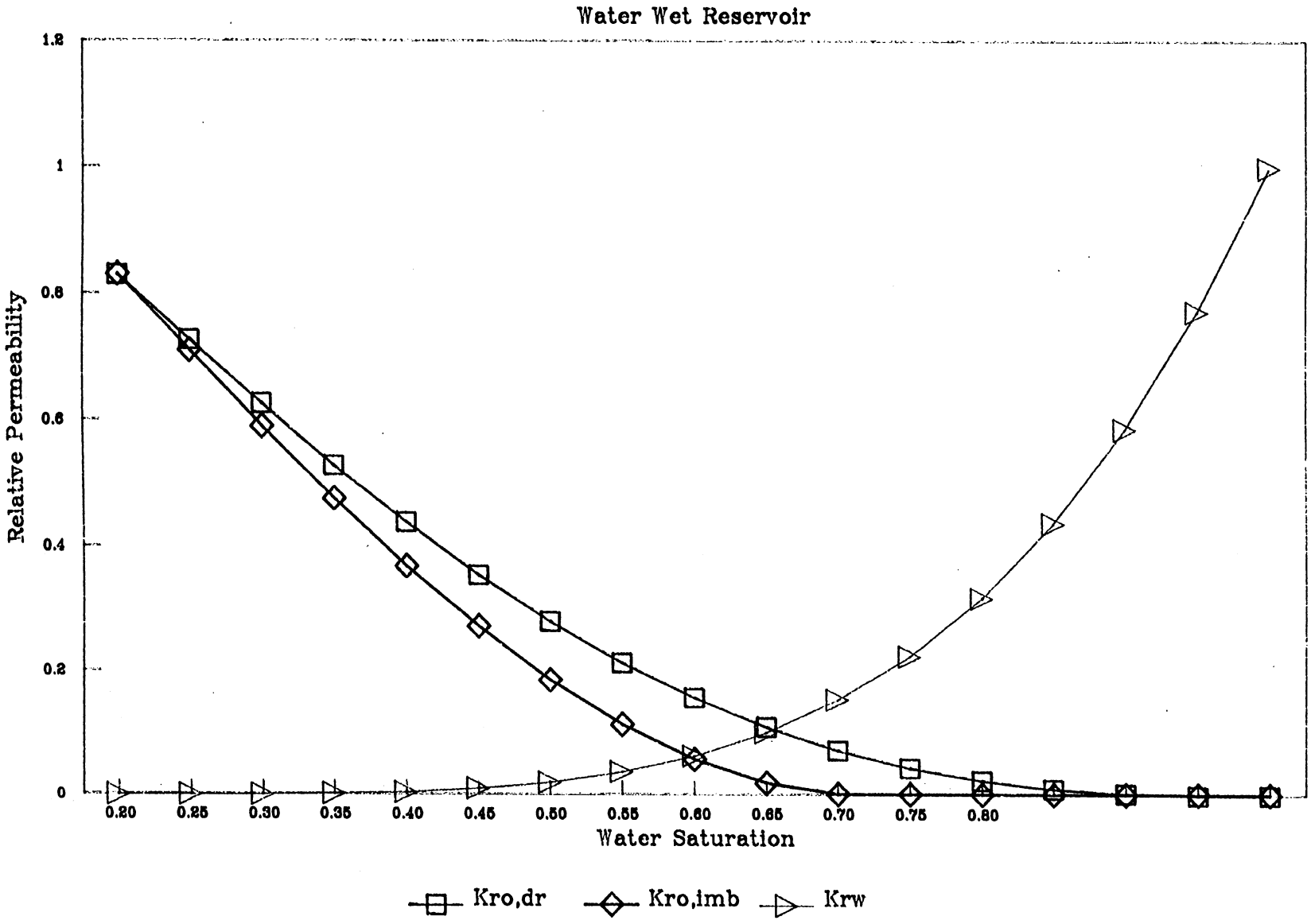
COMPANY	TEXACO INC.	DATE ON 2/15/73	FILE NO. 521-6753
WELL	W. H. STARK "B" NCT-1 NO. 35	DATE OFF 2/15/73	ENGRS. KUHLMAN
FIELD	NORTH PORT NECHES	FORMATION	ELEV.
COUNTY	ORANGE STATE TEXAS	DRLG. FLD.	CORES WELEX
LOCATION		REMARKS	

These analyses, opinions or interpretations are based on observations and material supplied by the client to whom, and for whose exclusive and confidential use, this report is made. The interpretations or opinions expressed represent the best judgment of Core Laboratories, Inc. (all errors and omissions excepted); but Core Laboratories, Inc. and its officers and employees, assume no responsibility and make no warranty or representations as to the productivity, proper operation, or profitableness of any oil, gas or other mineral well or sand in connection with which such report is used or relied upon.

Side Wall Core Analysis Data

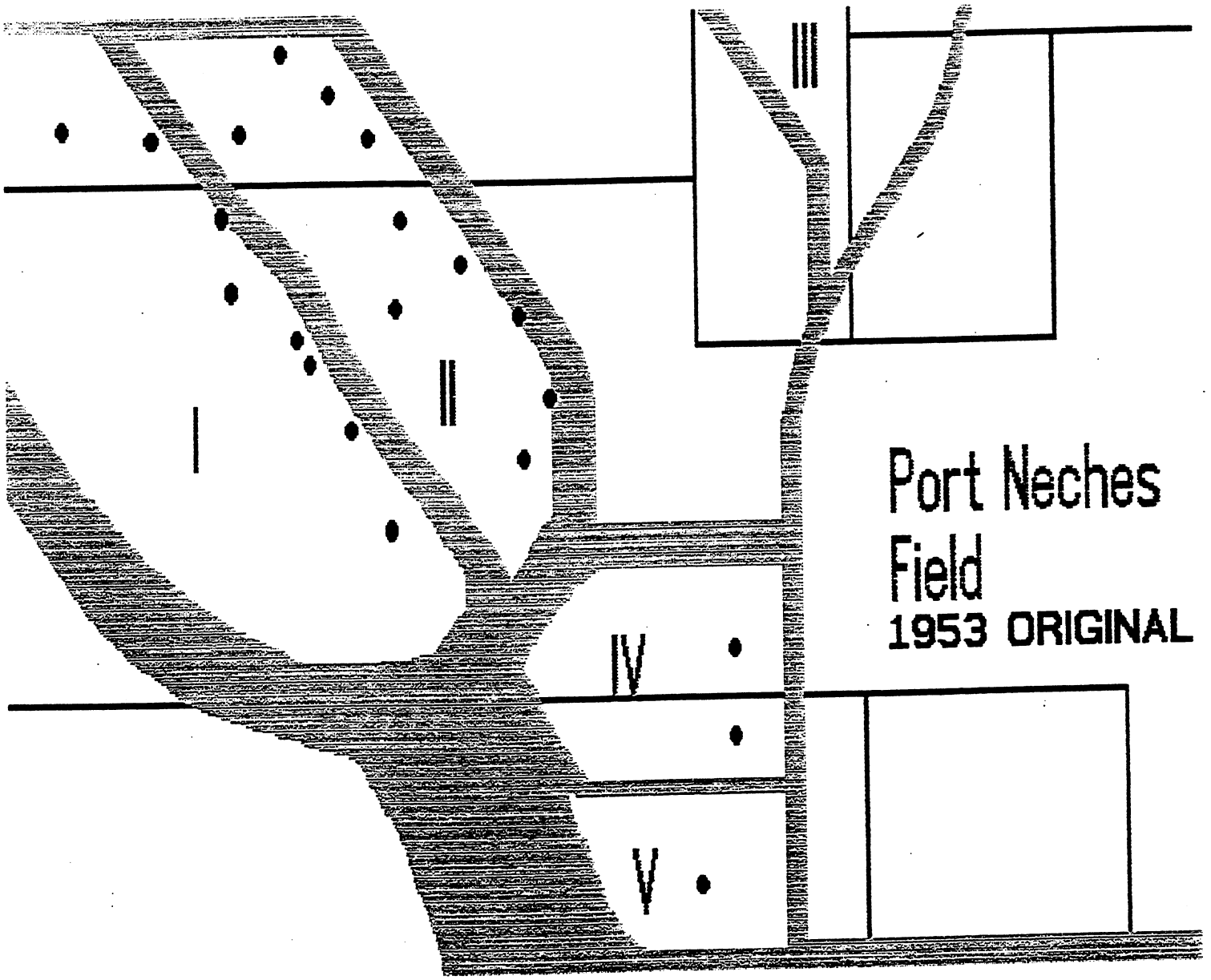
DEPTH, FEET	PERM., Md.	POR., %	% POR. SAT. OIL	% POR. SAT. TOTAL WATER	PROB. PROD.	% OIL VOL.	% GAS VOL	GAS DET	BULK DENS	DESCRIPTION
4647								0		SHALE V SLTY NO ODR NO FLU
4653								0		SHALE V SLTY W/LM & V LMY SD INCLS NO ODR SPTY MIN FLU
4718	3.4	20.3	0.0	75.3	(6)	0.0	5.0	0	2.13	SD VFG V SLTY V LMY W/SILT & SH LAMS NO ODR NO FLU
5598	0.8	20.2	1.0	91.6	(6)	0.2	1.5	0	2.27	LM CHALKY V FOSS NO ODR MIN FLU
5637	0.3	17.7	0.0	91.4	(6)	0.0	1.5	0	2.32	LM CHALKY FOSS NO ODR MIN FLU
5660	2.9	21.8	0.9	93.1	(6)	0.2	1.3	0	2.23	LM CHALKY V FOSS SHY NO ODR MIN FLU
5973	23.	26.8	6.7	65.2	OIL	1.8	7.5	5	2.01	SD VFG SLTY V SHY LAM LMY GOOD ODR LITE YEL STRKS FLU 43° API
5979	34.	27.0	6.3	65.1	OIL	1.7	7.7	3	2.01	SD F-VFG SLTY V SHY LAM SLI LMY GOOD ODR LITE YEL STRKS FLU
5984	560.	28.1	11.7	63.3	OIL	3.3	7.0	6	2.01	SD F-VFG SLI SLTY SLI LMY W/SH STRKS GOOD ODR YEL FLU 43° API
5988	1230.	29.5	14.2	59.7	OIL	4.2	7.7	3	1.96	SD F-VFG CLN W/SH INCLS GOOD ODR YEL FLU
6083	2.1	19.8	0.0	74.7	(6)	0.0	5.0	0	2.21	SD F-VFG V SLTY V SHY LMY NO ODR NO FLU
6100	<0.1	13.4	0.0	70.8		0.0	3.9	0	2.36	SD VFG SLTY V LMY HD NO ODR NO FLU
6172	3.5	22.7	0.0	77.6	(6)	0.0	5.1	0	2.13	SD F-VFG V SLTY V SHY V LMY NO ODR NO FLU
6177	53.	25.3	0.0	88.8	WATER	0.0	2.8	0	2.11	SD F-MG V SLTY SHY LMY NO ODR NO FLU
					(6)	LOW PERMEABILITY				
					(13)	PROBABLY WATER PRODUCTIVE				

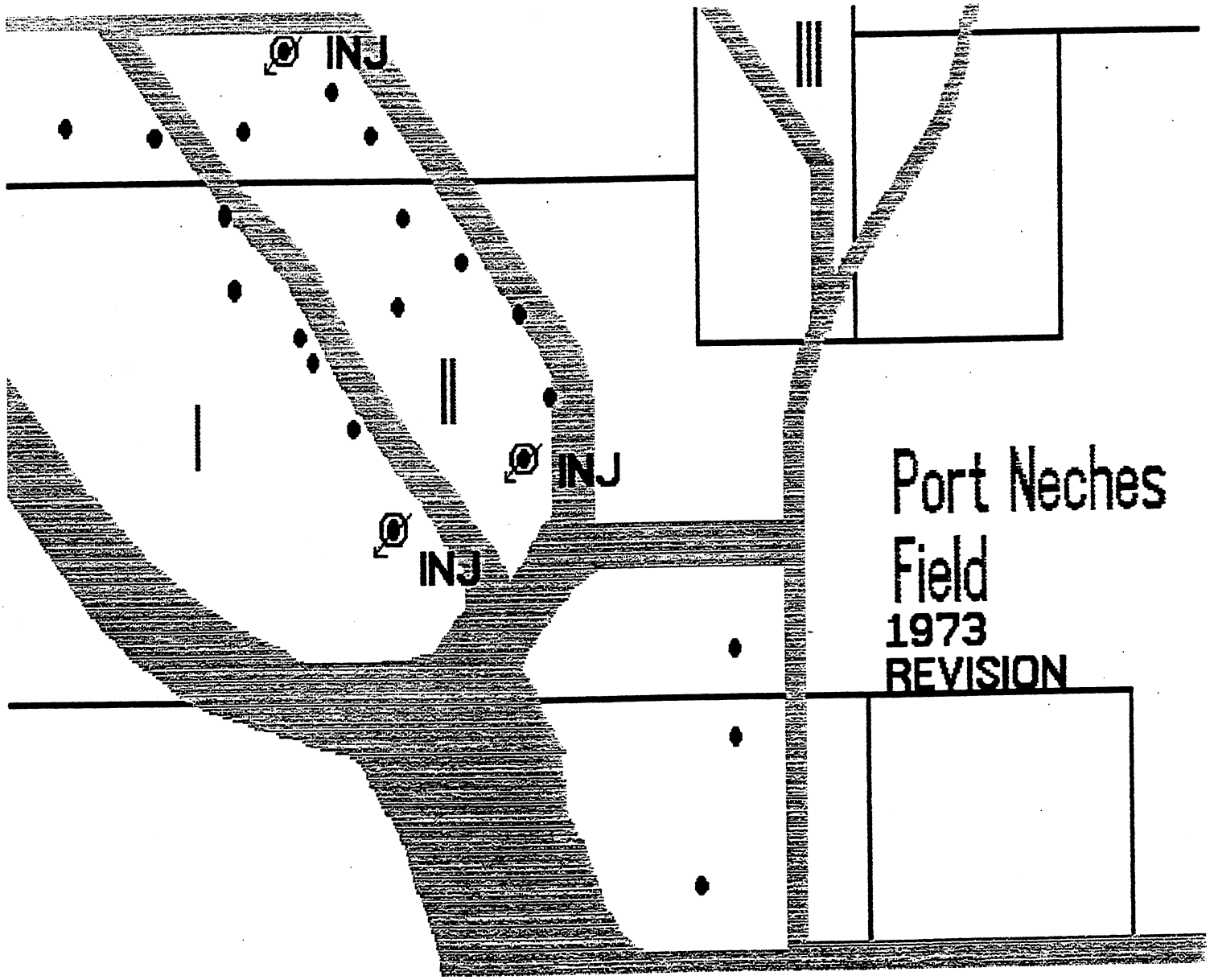
Oil–Water Relative Permeabilities



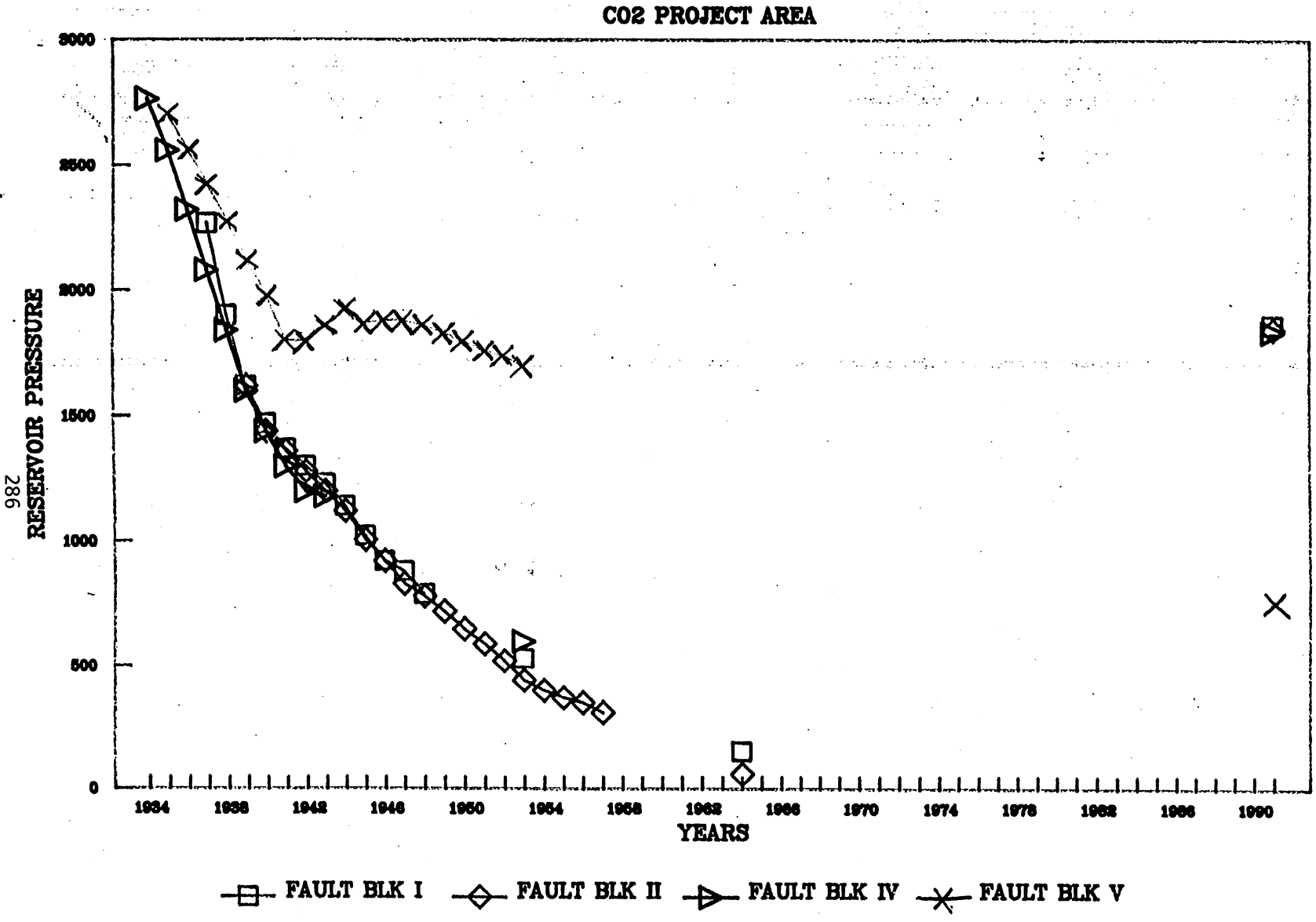
STRUCTURAL MAPPING

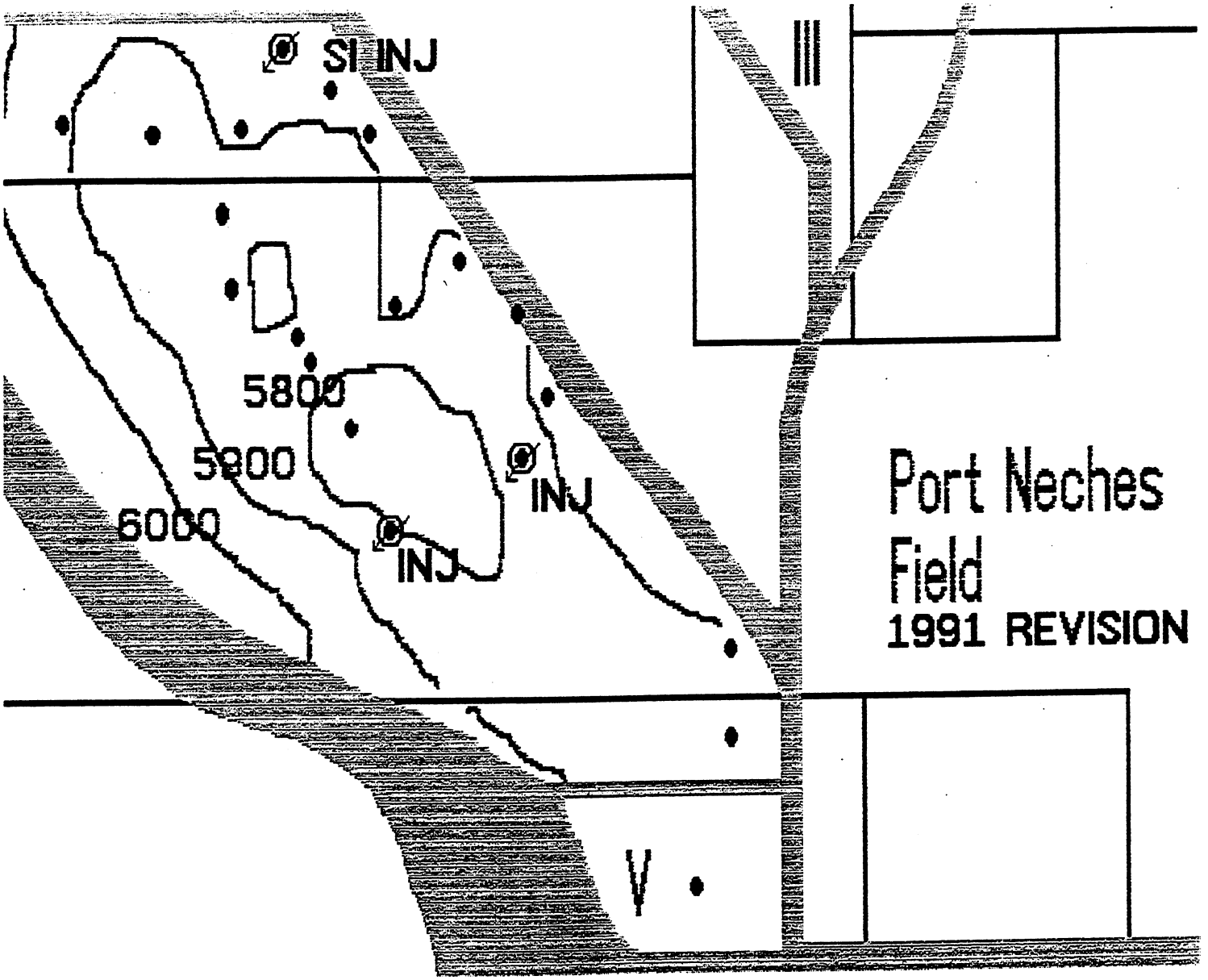
Refinements to the structural mapping of the Marginulina reservoir were made by examining the reservoir pressure history of each fault block identified by previous studies. It became apparent that Fault Blocks I, II, and IV were in communication, while Fault Block V was in a separate block, and acted upon by a partial waterdrive. This information passed on to the geology group resulted in a completely different interpretation of the geological structure. This new data was incorporated in a reservoir model to simulate the primary and secondary production histories. It is probable that 3-D seismic will be run the field during 1992 or 1993 to better define these fault blocks.


I
II
III
IV
V
Port Neches
Field
1953 ORIGINAL


INJ
INJ
INJ
I
II
III
Port Neches
Field
1973
REVISION

PORT NECHES FIELD



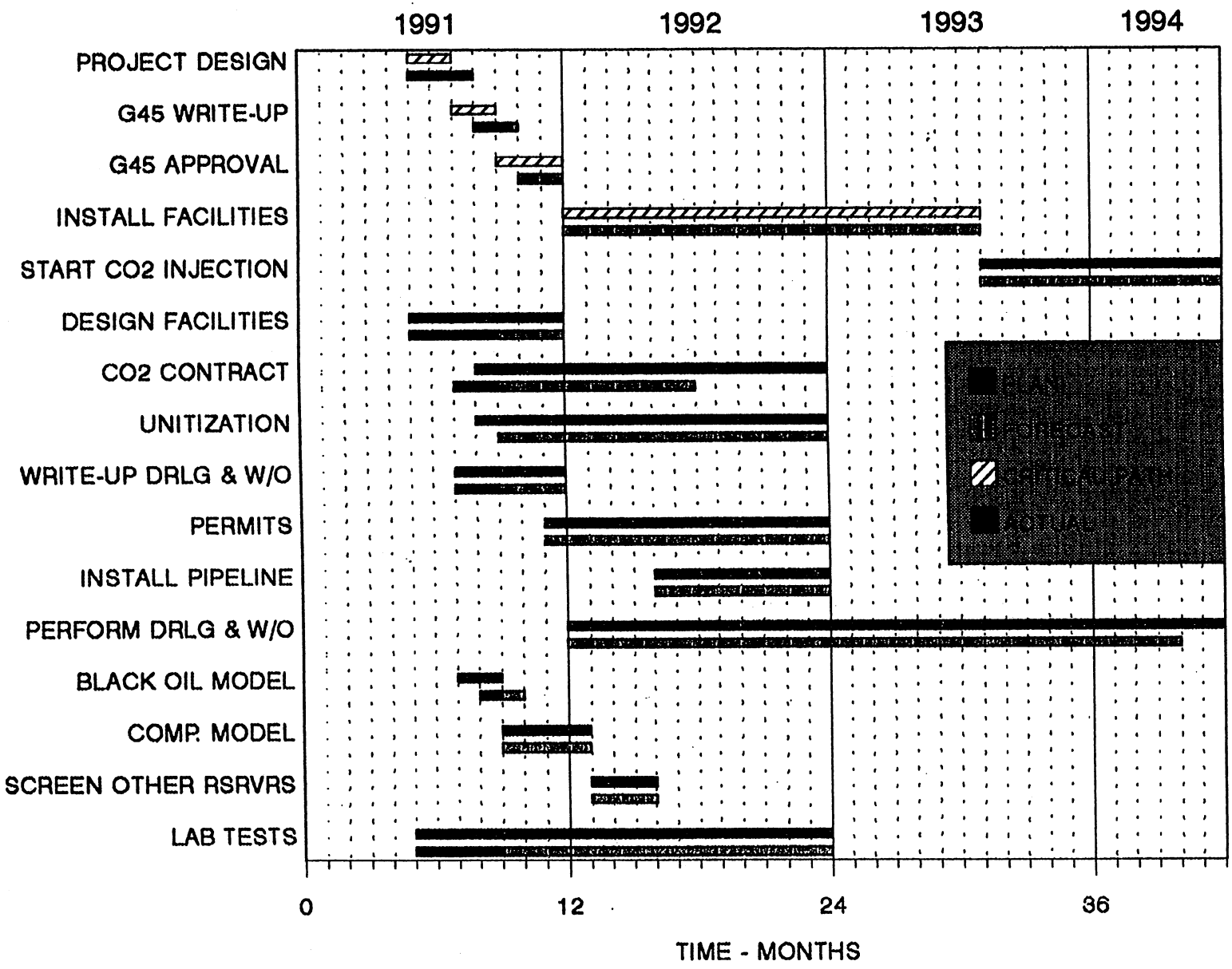

SI INJ
III
5800
5900
6000
INJ
INJ
V
Port Neches
Field
1991 REVISION

PROJECT DESIGN / IMPLEMENTATION

Project design for the Port Neches Field CO2 miscible flood began in March, 1991 with the forming of the CO2 team in Harvey, Louisiana. Attached is a project schedule indicating the requirements of work necessary to meet cycle time goals.

Following the project forecast schedule are calculations showing the required fillup volumes necessary to pressure the reservoir to original pressure. Material balance calculations indicate that the presence of a steady state aquifer reduces this fillup requirement. The influx of water into the closed reservoir allows the reservoir to be pressured much sooner. Please see the attached reservoir pressure history matches.

PORT NECHES


1991
1992
1993
1994
PROJECT DESIGN
G45 WRITE-UP
G45 APPROVAL
INSTALL FACILITIES
START CO2 INJECTION
DESIGN FACILITIES
CO2 CONTRACT
UNITIZATION
WRITE-UP DRLG & W/O
PERMITS
INSTALL PIPELINE
PERFORM DRLG & W/O
BLACK OIL MODEL
COMP. MODEL
SCREEN OTHER RSRVRS
LAB TESTS
PLAN
ACTUAL
0
12
24
36
TIME - MONTHS

PORT NECHES FIELD
MARGINULINA RESERVOIRS

Fault Blocks I, II, IV

$$\text{OOIP} = \frac{(7758)(0.30)(0.80)(30)(240)}{1.33} = \underline{10\ \text{MMSTB}}$$

Oil Recovery = 5.7/10.0 = 57 %

Reservoir Voidage

Cum Oil	5,683,806 BO	X	1.33 =	7,559,462	RB
Cum Wtr	8,980,280 BW	X	1.03 =	9,249,688	RB
Cum Gas	4,434,119 - (410X5684)	X	1.02 =	2,103,679	RB
Total				18,912,829	RB
Cum Inj	8,882,185 BW	X	1.03 =	(9,148,651)	RB
Total				9,764,178	RB

Initial CO2 Requirement (2 MCF CO2 = 1 RB)

(9,764,178 RB)(2 MCF/RB) = 19.5 BCF
(5,700,000 RB)(2 MCF/RB) = (11.4 BCF) (water influx)
8.1 BCF

*******Pressure up with water at 7500 BWPD for 550 days*******

One Pore Volume of CO2

(7758)(0.30)(0.80)(30)(240)(2.0) = 26.8 BCF

Fault Block V

$$\text{OOIP} = \frac{(7758)(0.30)(0.80)(33)(30)}{1.31} = \underline{1.4\ \text{MMSTB}}$$

Oil Recovery = 0.6/1.4 = 43 %

Reservoir Voidage

Cum Oil	614,203 BO	X	1.33 =	816,890	RB
Cum Wtr	718,501 BW	X	1.03 =	740,056	RB
Cum Gas	429,414 - (412X614)	X	1.02 =	179,975	RB
Total				1,736,921	RB

Initial CO2 Requirement (2 MCF CO2 = 1 RB)

(1,736,921 RB)(2 MCF/RB) = 3.5 BCF
(1,250,000 RB)(2 MCF/RB) = (2.5 BCF) (water influx)
1.0 BCF

*******Aquifer feed-in shortens time to pressure up*******
****Pressure rose from 990 psi to 2100 psi in 4 months****
****Approximate fillup time 4 months at 5 MMCFPD****

One Pore Volume of CO2

(7758)(0.30)(0.80)(33)(30)(2.0) = 3.7 BCF

RESERVOIR FLUID PROPERTIES / RESERVE CALCULATION

Attached are the reservoir fluid properties used in the analysis for the Port Neches Field Marginulina reservoir. Reservoir fillup volumes are calculated. The use of Texaco's in-house Oilwat material balance program was very useful in showing that these fillup volumes are reduced by aquifer influx into these sealed reservoirs. The best reservoir pressure history match was obtained for the waterflooded fault block by implementing a steady state aquifer, though it is a very weak aquifer. A completely sealed reservoir, ie no aquifer influx, would not have pressured up as soon as the reservoir actually did, thus indicating that it was affected by water influx.

Port Neches Field

Reservoir and Fluid Properties

Average Porosity (%)	30
Average Permeability (md)	750
Bo (RB/STB)	1.31
Pi (psi)	2700
Ti (deg-F)	165
Pbp (psi)	2550
Oil Viscosity @ 2700 psi (cp)	0.62
Solution GOR (scf/STB)	500
Oil Gravity (deg-API)	38
Wtr Viscosity @ 2700 psi (cp)	0.43
Wtr Compressibility (psi -1)	3.00 X 10 -6
Rock Compressibility (psi -1)	3.00 X 10 -6
MMP (psia)	3310

Oilwat Material Balance Program
Input Parameters

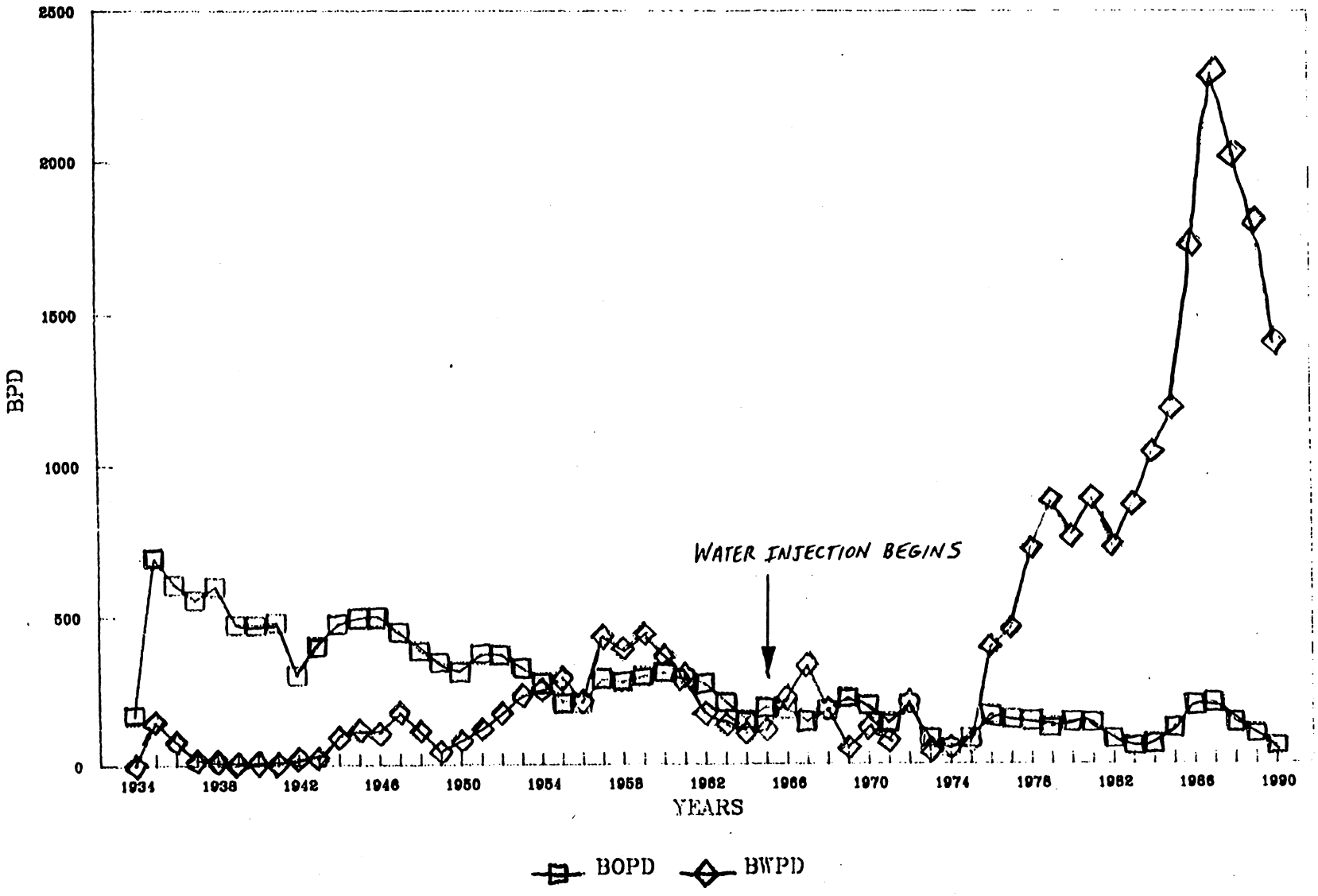
- Production Data
- Injection Data
- Pressure History
- PVT Data
- Gas Cap / Oil Zone Ratio
- Aquifer / Oil Zone Ratio (For Radial Aquifer)
- Shape Of Aquifer

Oilwat Material Balance Program
Output Generated

- Oil-In-Place For Various Aquifer Types
- Aquifer Influx
- Pressure History Prediction

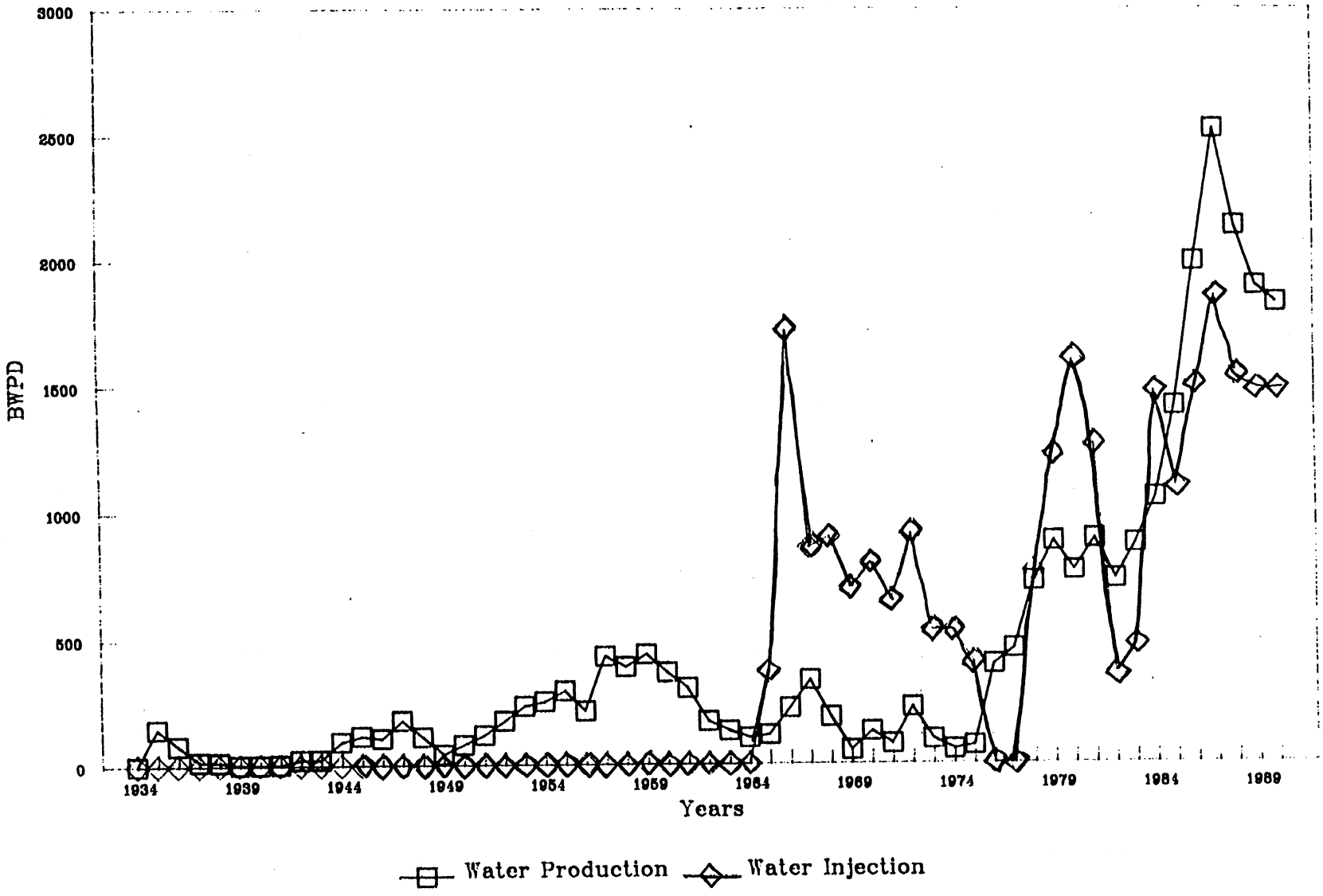
PORT NECHES FIELD

WATERFLOOD PROJECT AREA

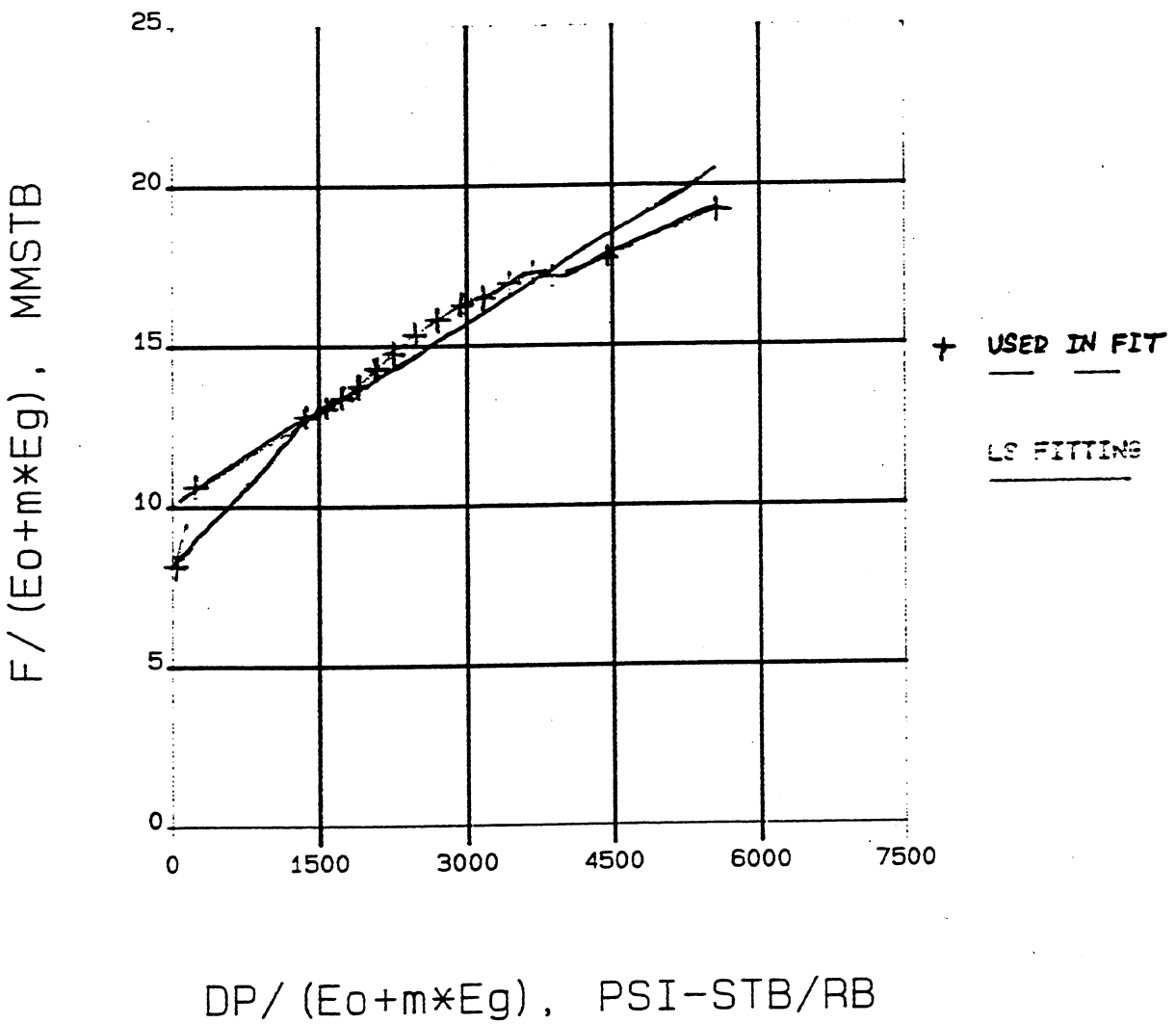


Port Neches Field

Waterflood Project Area



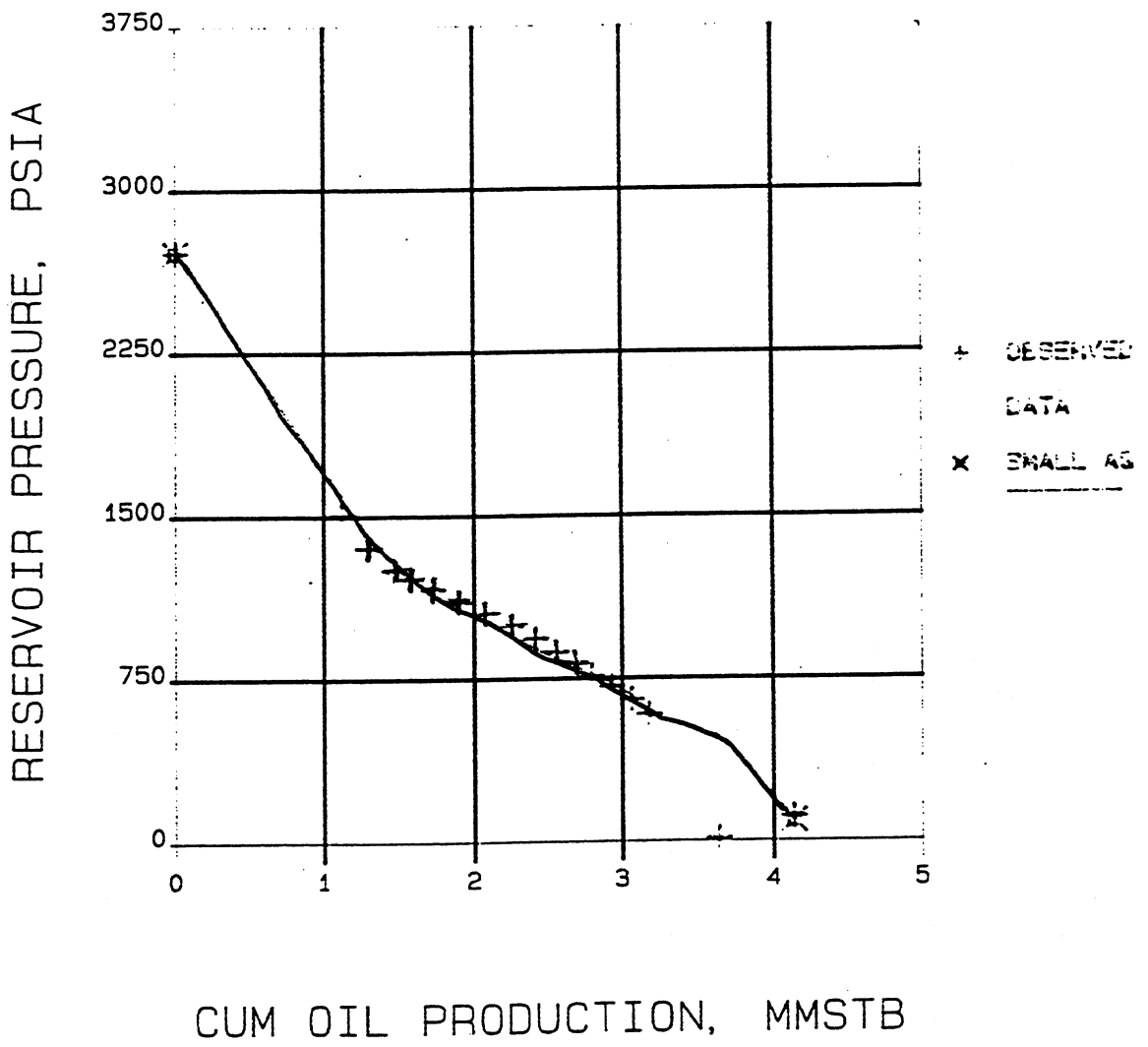
PORT NECHES FIELD - WATERFLOOD AREA
SMALL AQUIFER/UNDERSAT RESERVOIR
OIP = 10.09 MMSTB, S() = 7.49 %



AQ CONST= 1878.16

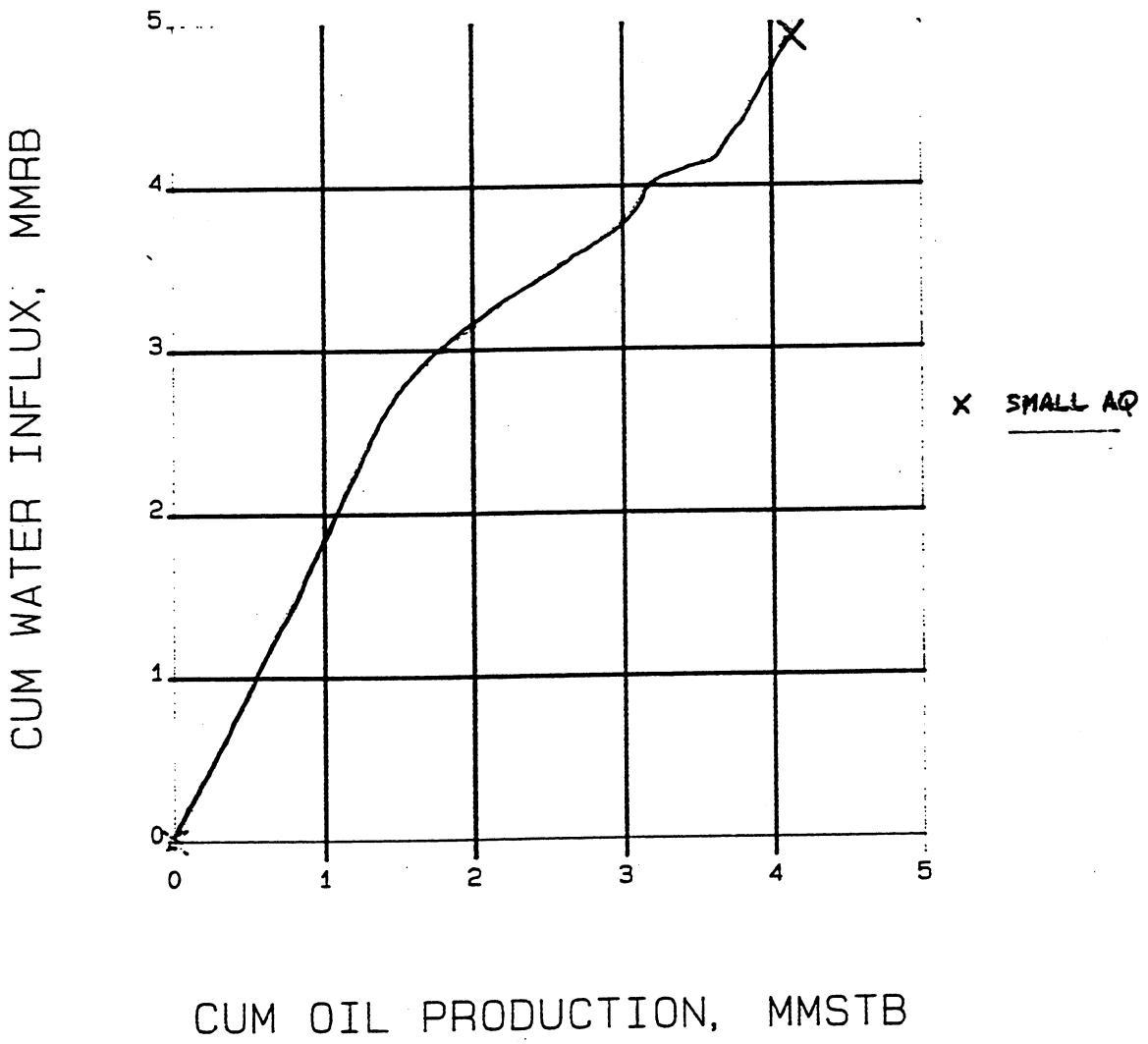
OILWAT 4.14

PORT NECHES FIELD - WATERFLOOD AREA
COMPARISON OF PRESSURE MATCHES



OILWAT 4.14

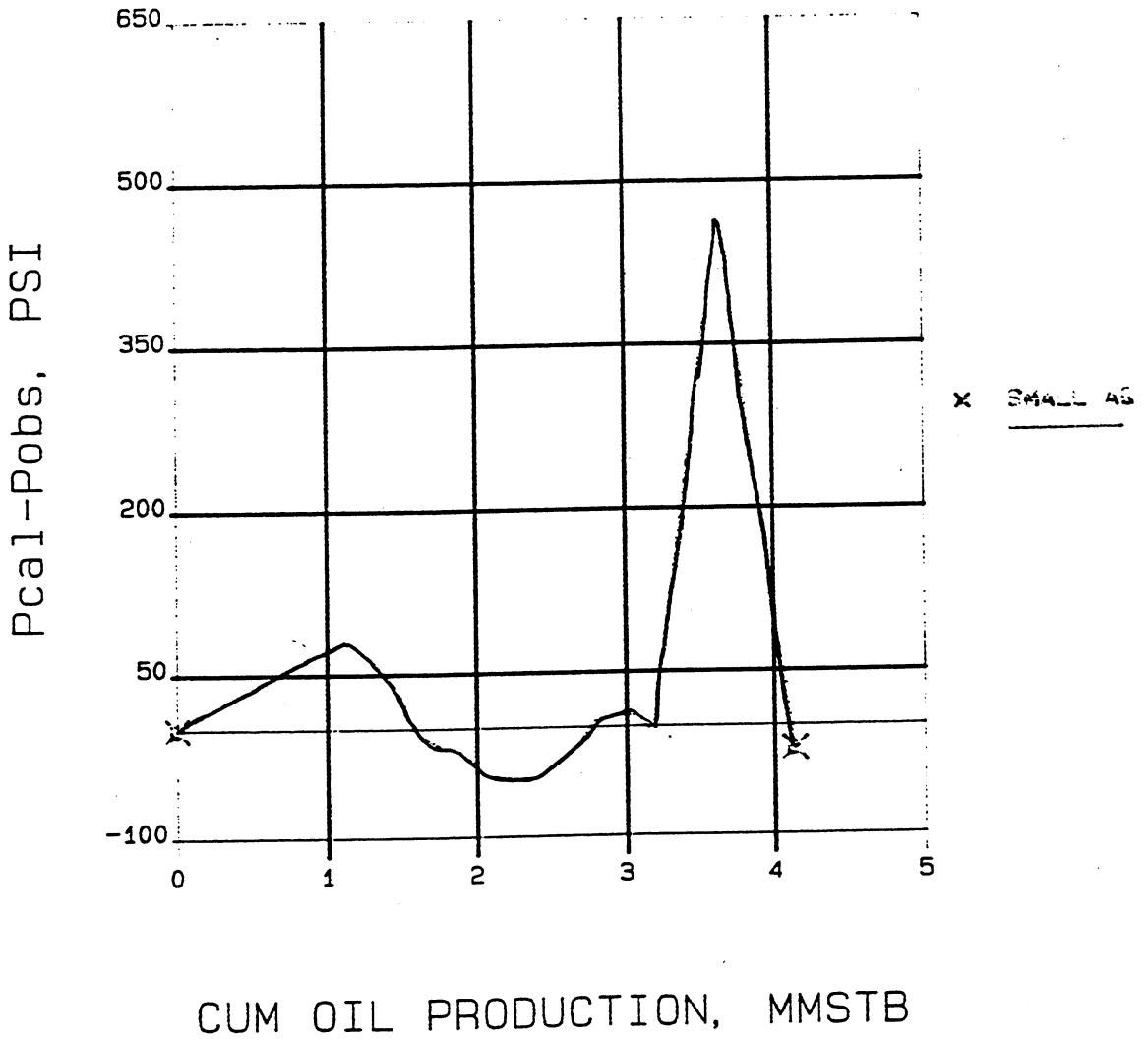
PORT NECHES FIELD - WATERFLOOD AREA
CUM WATER INFLUX vs CUM OIL PRODUCTION



OILWAT 4.14

PORT NECHES FIELD - WATERFLOOD AREA

PRESSURE DIFFERENCE vs CUM OIL PRODUCTION



OILWAT 4.14

AQUIFER TYPE
SMALL AQUIFER ??

AQUIFER CONSTANT = 1878 RB/PSI = (Cw + Cf) Vaq

Cw + Cf = 6 X 10 -6

Vaq = 313 MMRB = 4075 ACRES (33 FT NET HEIGHT)

AQUIFER SIZE / RESERVOIR SIZE = 4075/240 = 17/1

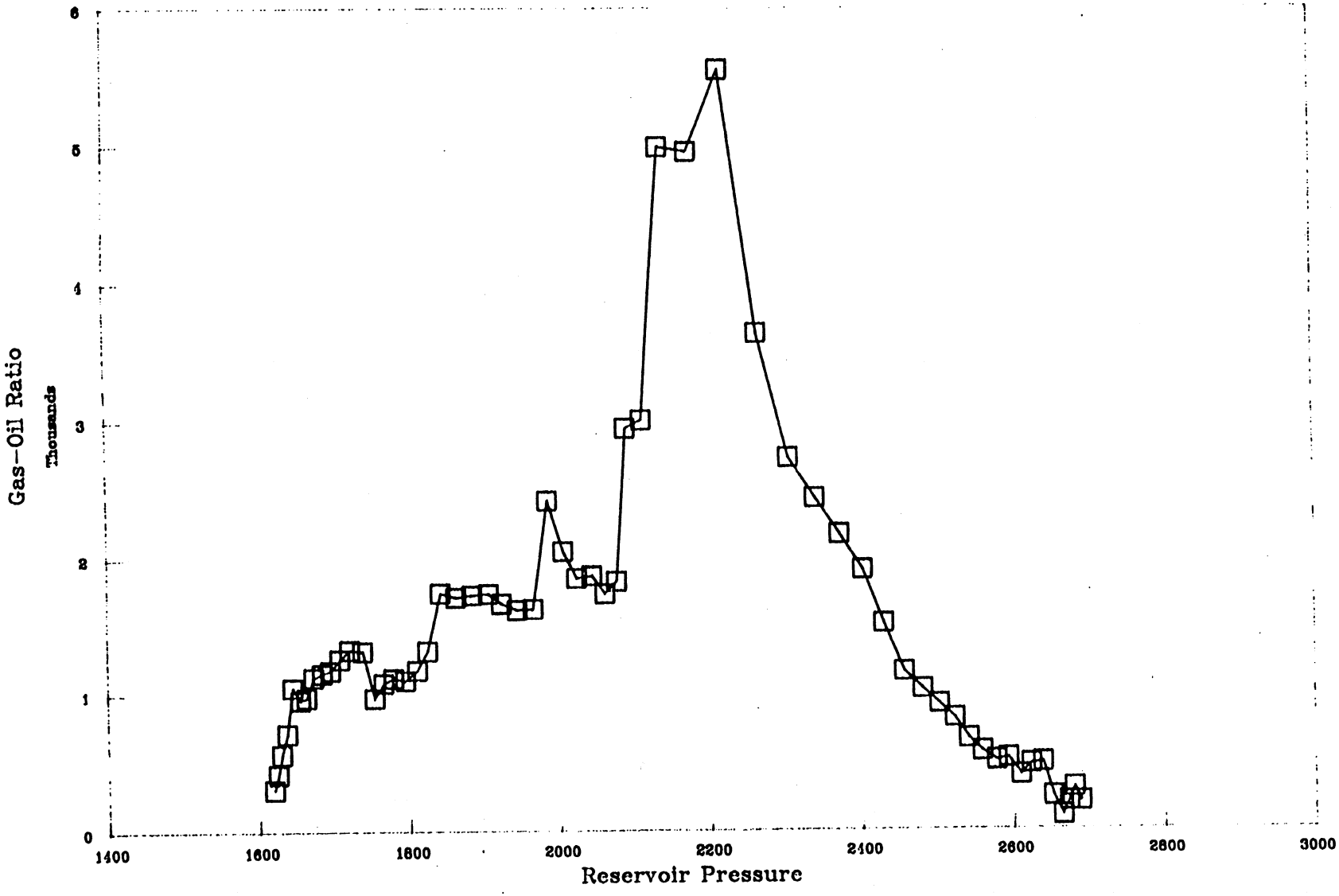
THE DISPLACEMENT OF FLUID DUE STRICTLY TO THE EXPANSION OF WATER AND ROCK ?

FILLUP VOLUME MUST REPLACE ALL OIL, WATER, AND FREE GAS VOIDAGE, LESS WATER INJECTION = 10 MMRB !!

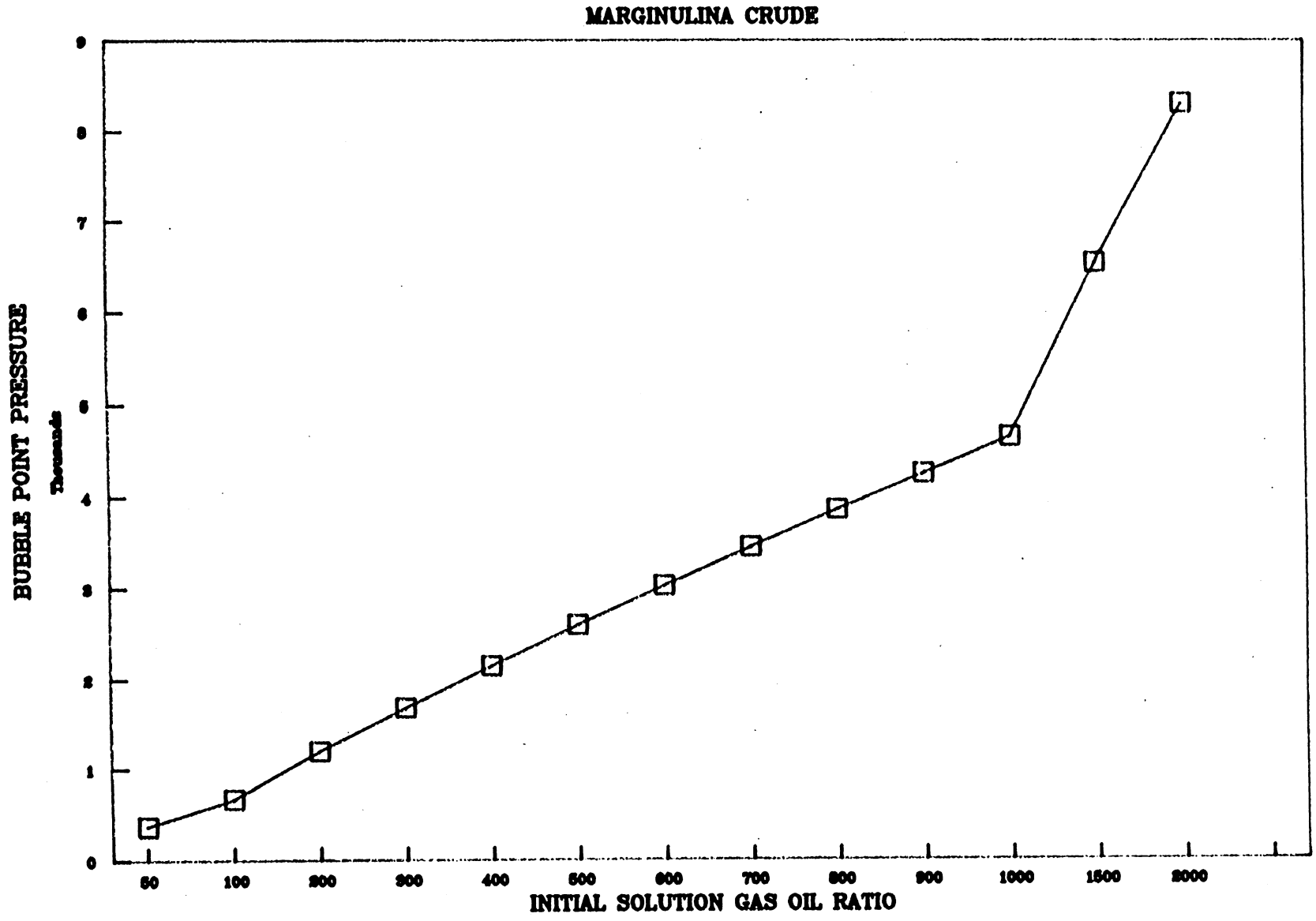
WATER INFLUX DOES NOT ASSIST IN FILLUP REQUIREMENTS.

Port Neches Field

Project Area GOR vs Pressure



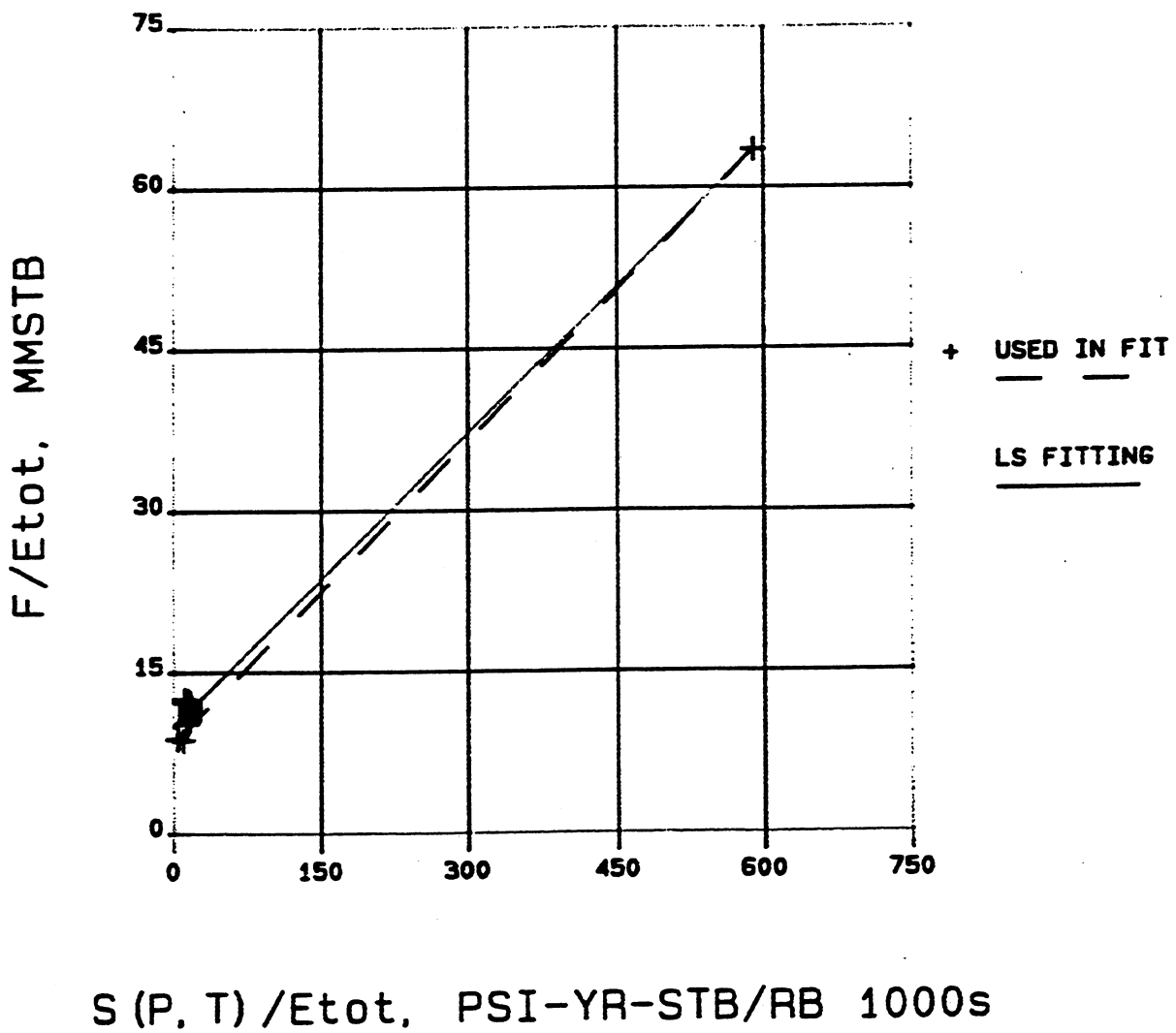
PORT NECHES FIELD



Port Neches Field Waterflood Area
Oilwat OOIP Results

Aquifer Type	Rsi=420 Pbp=2205	Rsi=500 Pbp=2554
No Aquifer	10.87	9.06
Schilthuis SS	13.03	10.06
Hurst SS	12.58	9.73
USS Infinite Linear	10.25	8.03
USS Radial	8.61	8.01

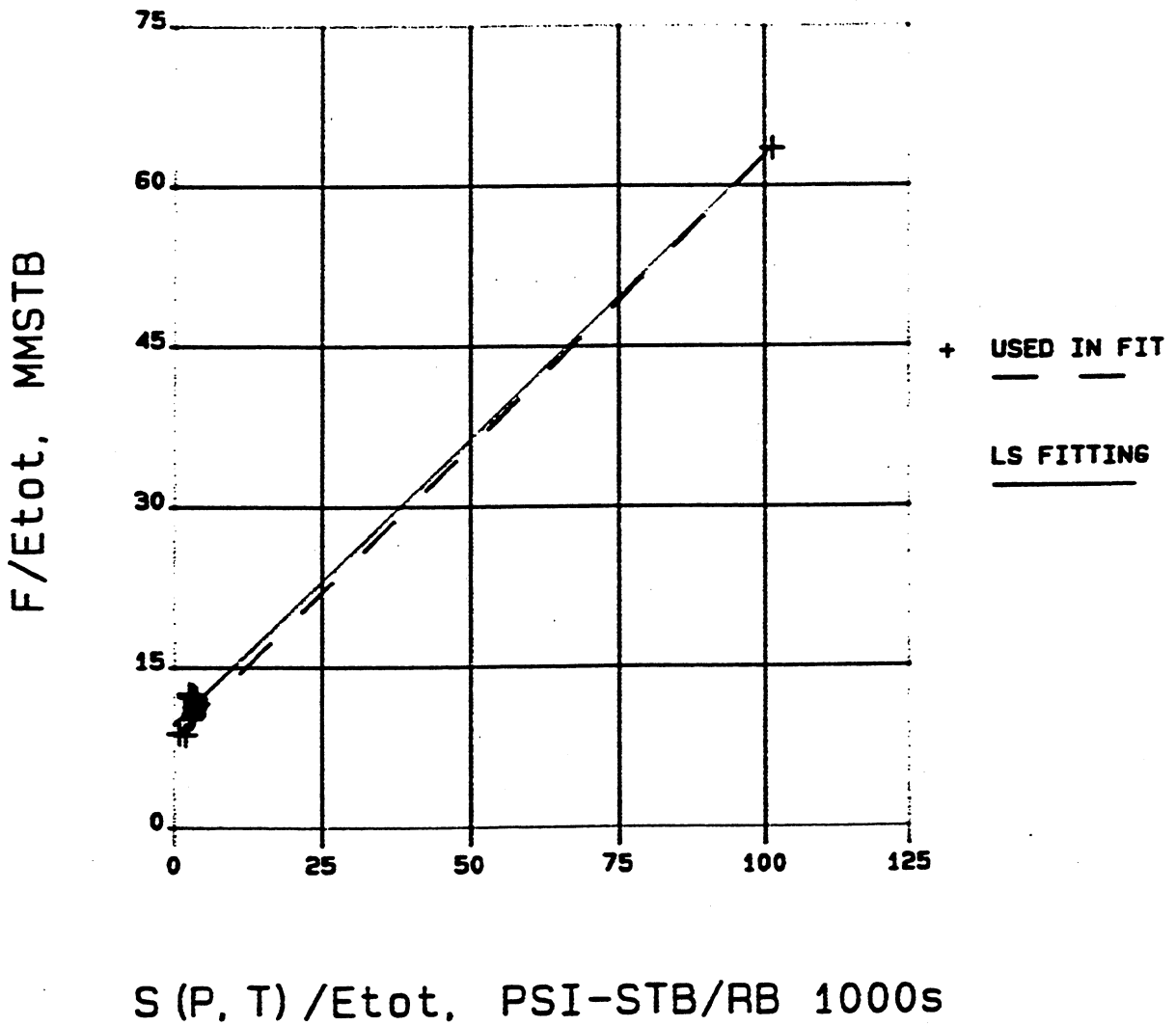
PORT NECHES FIELD - WATERFLOOD AREA
SCHILTHUIS STEADY-STATE AQUIFER
OIP = 10.06 MMSTB, S() = 1.63 %



AQ CONST= 90.69

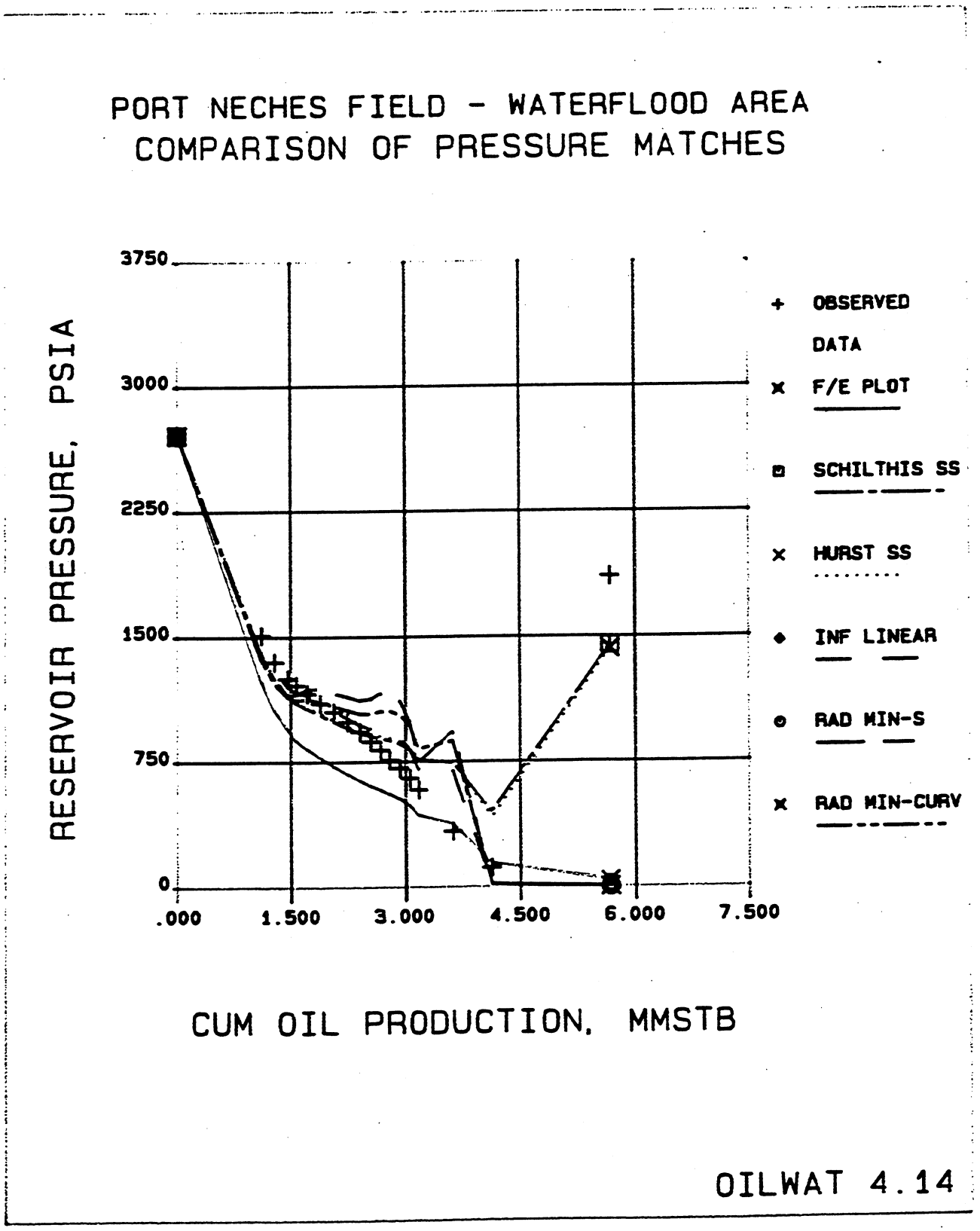
OILWAT 4.14

PORT NECHES FIELD - WATERFLOOD AREA
HURST STEADY-STATE AQUIFER
OIP = 9.73 MMSTB, S() = 1.51 %

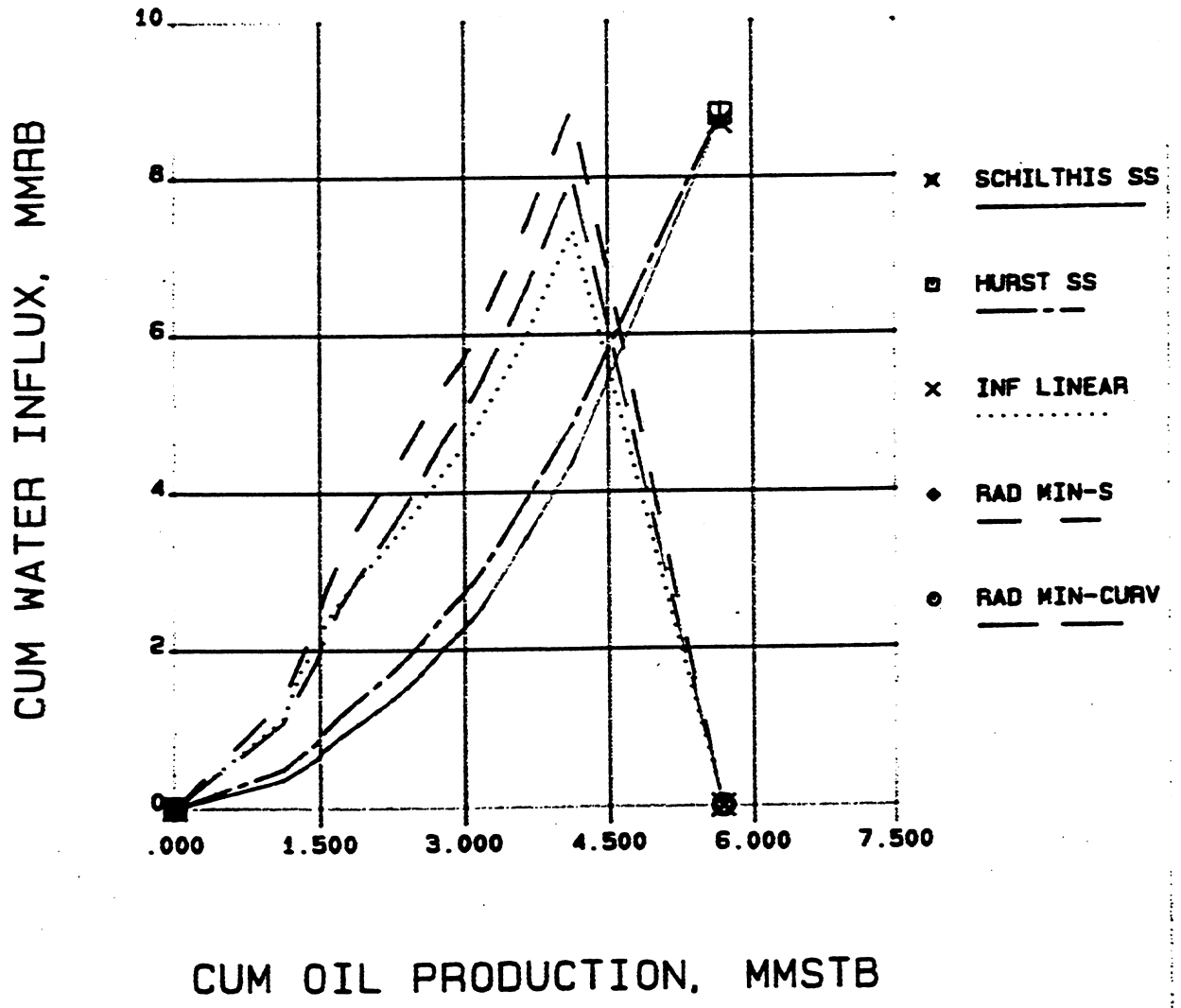


AQ CONST= 531.43

OILWAT 4.14

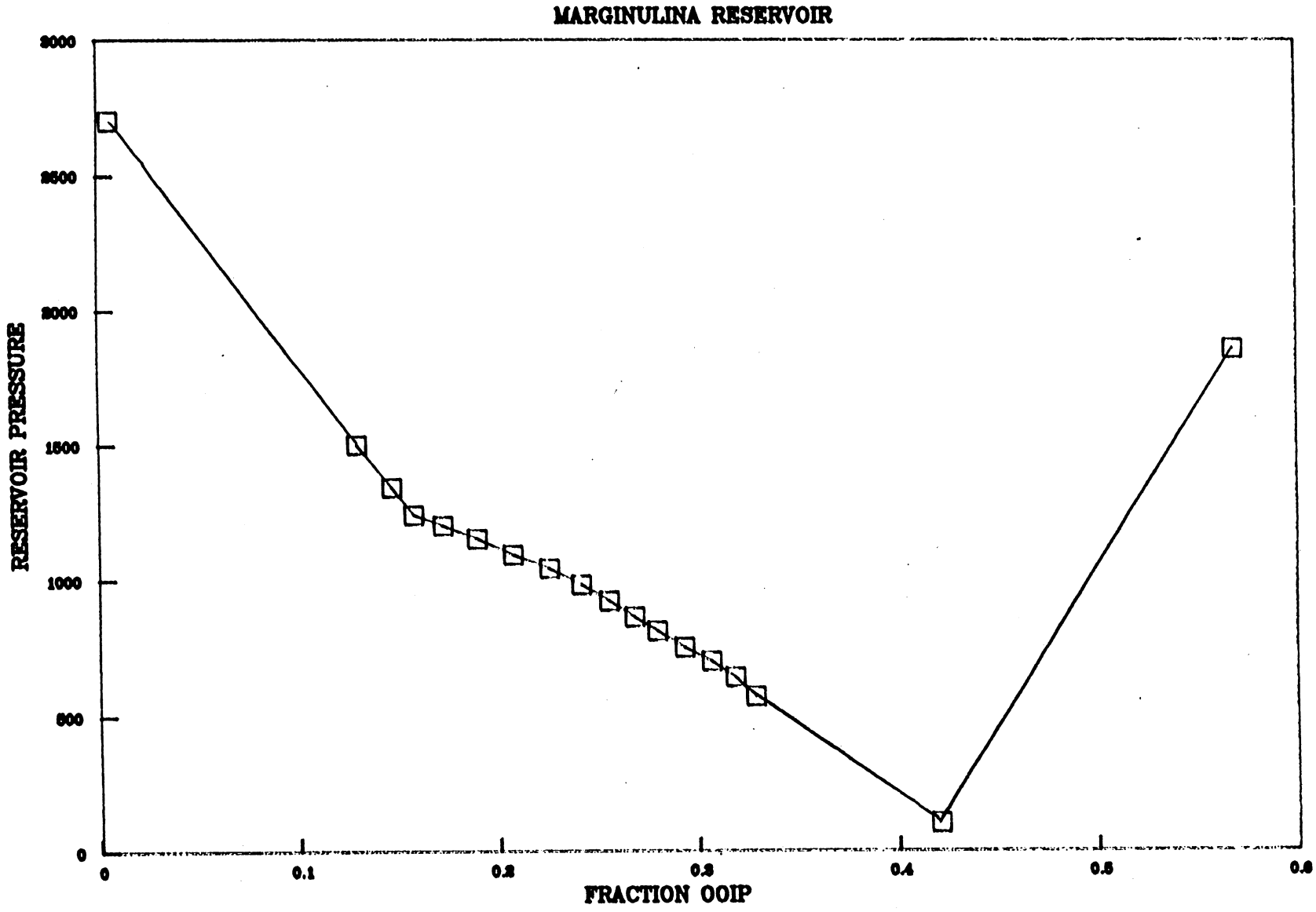

PORT NECHES FIELD - WATERFLOOD AREA
COMPARISON OF PRESSURE MATCHES
RESERVOIR PRESSURE, PSIA
3750
3000
2250
1500
750
0
.000
1.500
3.000
4.500
6.000
7.500
CUM OIL PRODUCTION, MMSTB
OBSERVED DATA
F/E PLOT
SCHILTHIS SS
HURST SS
INF LINEAR
RAD MIN-S
RAD MIN-CURV
OILWAT 4.14

PORT NECHES FIELD - WATERFLOOD AREA
CUM WATER INFLUX vs CUM OIL PRODUCTION



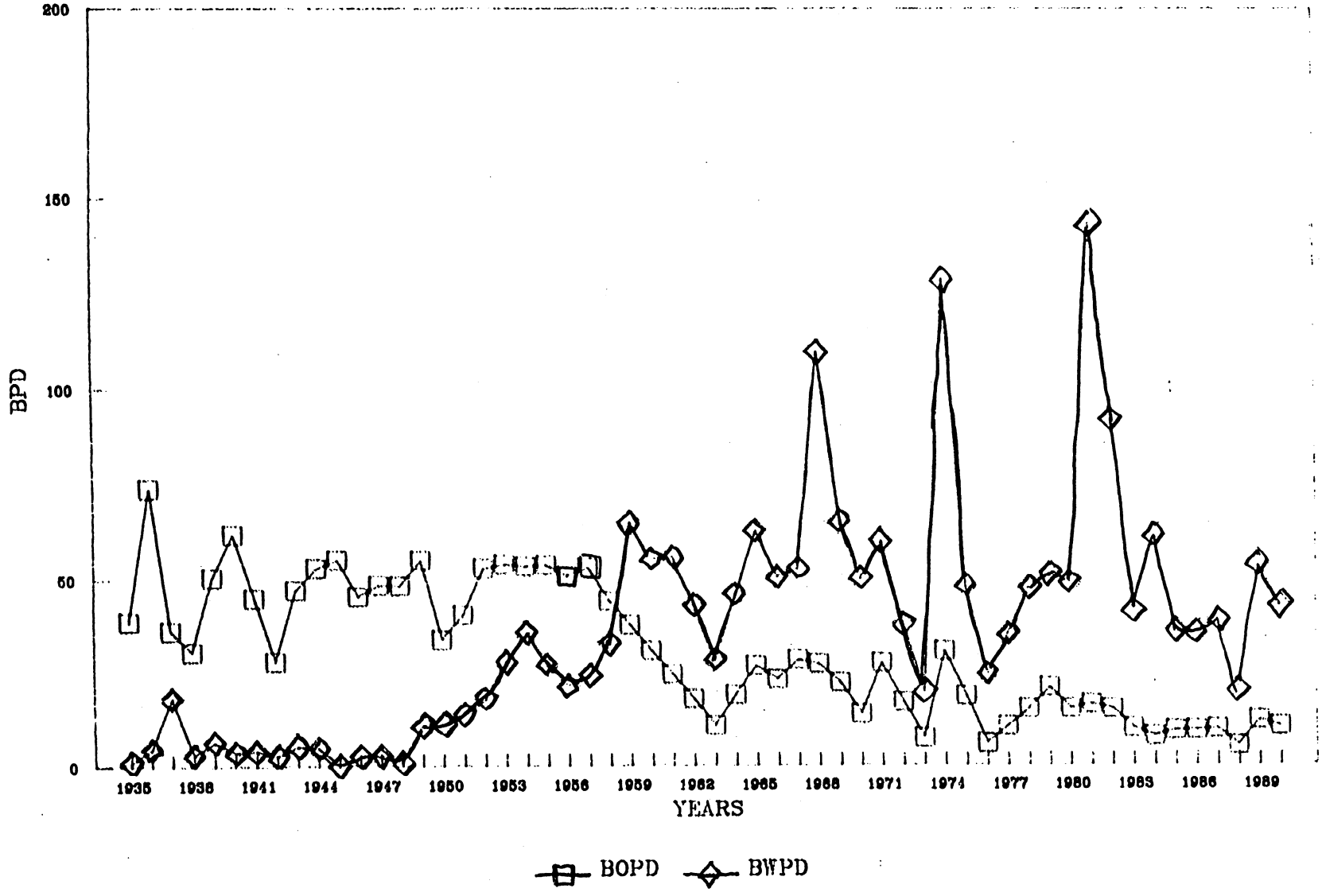
OILWAT 4.14

PORT NECHES FIELD



PORT NECHES FIELD

POLK "B" NO. 5



Port Neches Field Faultblock 5
Oilwat OOIP Results

Aquifer Type	Rsi=420 Pbp=2205	Rsi=500 Pbp=2554
No Aquifer	2.69	1.46
Schilthuis SS	2.08	1.38
Hurst SS	1.05	0.85
USS Infinite Linear	1.69	0.80
USS Radial	3.52	3.12

Oilwat Results
Port Neches Field

1.) Under Primary Depletion From 2700 psi To 100 psi, Large Waterflood Area Acted Like A Small (Pot) Aquifer, With 5 MMSTB Of Water Influx.

2.) Waterflood Pressure Response Data Indicates However, That Reservoir Was Actually Acted Upon By A Steady State Type Aquifer, As Seen By Reduced Fillup Time.

3.) This Same Type Aquifer Influx Into The Small Fault Block, Accounts For The Pressure Buildup In The Reservoir Over An 83 Day Shut-in Period During 1991.

4.) Oil Reserve For Large Waterflood Area = 10.0 MMSTB
Oil Reserve For Small Fault Block = 1.4 MMSTB

Material Balance Evaluation
Conclusions

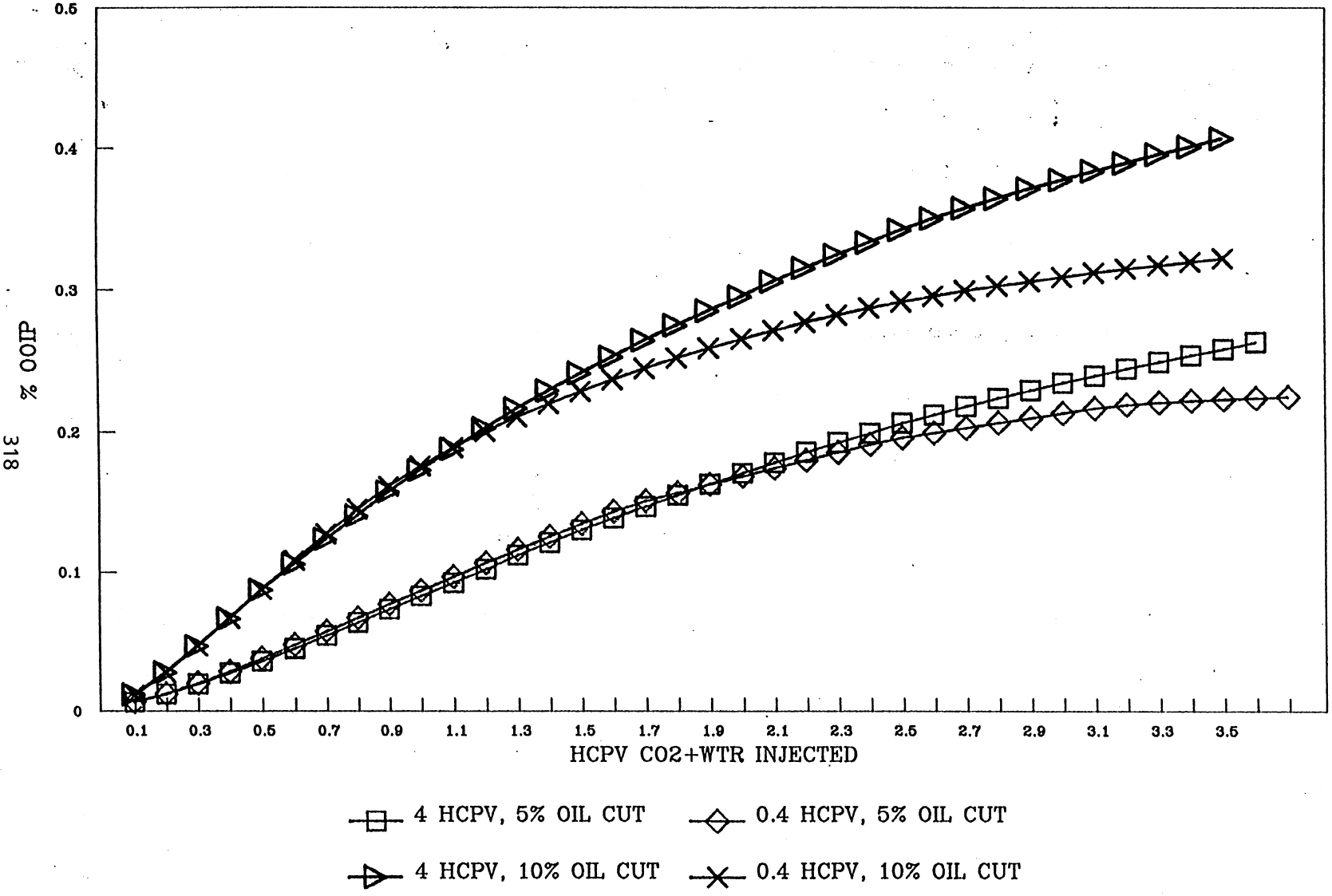
- Bubble Point Pressure And Initial Solution GOR Very Critical In Oil-In-Place Determination
- Various Aquifer Types Can Create Same Pressure History Profile
- Determination Of What Type Aquifer Exists Is Critical To CO2 Project Design
- The Oilwat Material Balance Program Is An Excellent Reservoir Evaluation Tool

RESERVOIR MODELING

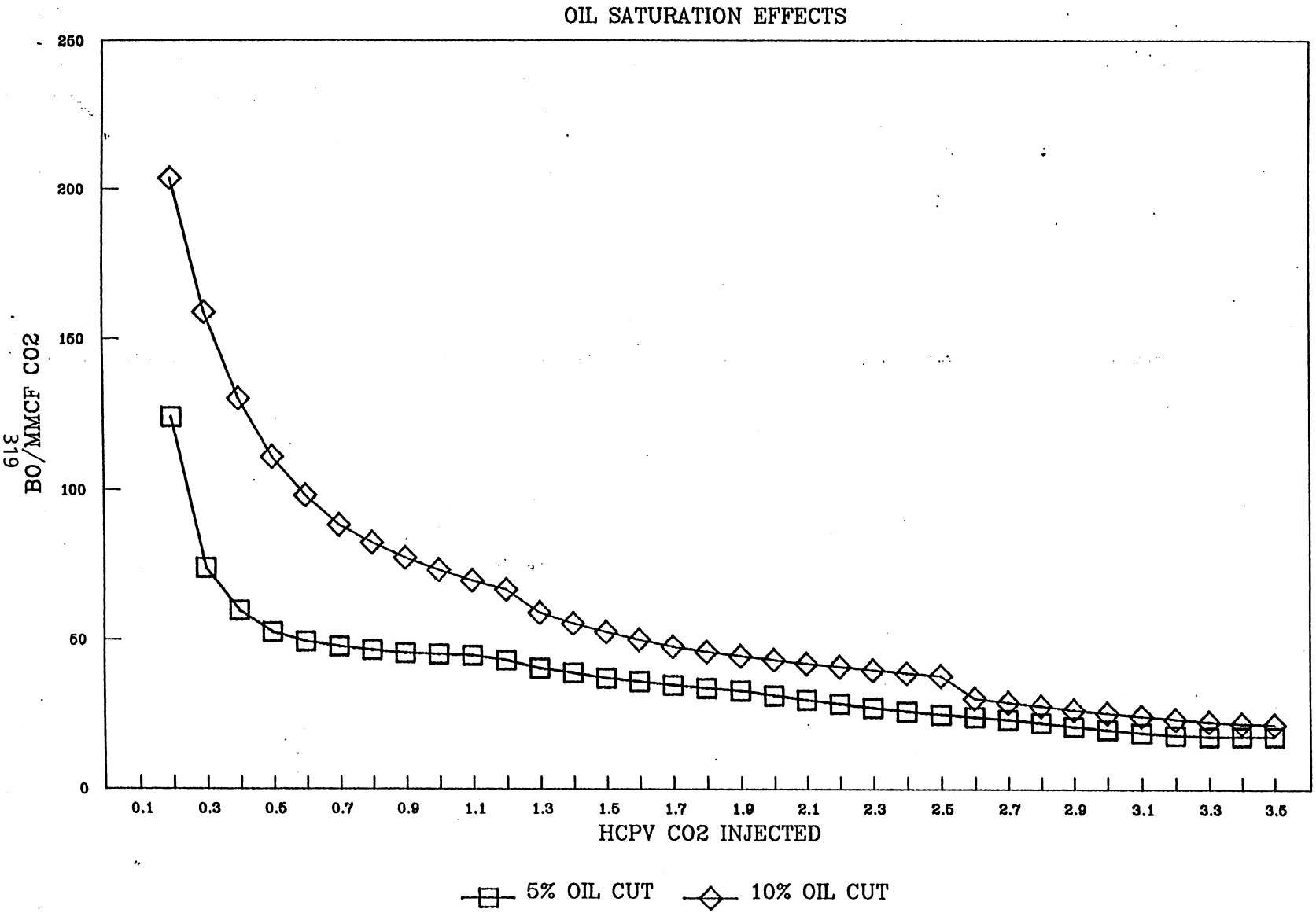
The use of Texaco's modified DOE CO2PM program was utilized initially to determine the oil, water, and gas production forecast for the Marginulina reservoir. This program is for a 5-spot pattern, which does not truly represent the Port Neches reservoir configuration, yet was useful once a dimensionless curve was developed which was independant of reservoir shape. The major adjustment which had to be made, was to the oil yield curve due to earlier CO2 breakthrough that forecast. This was confirmed by a compositional program which was purchased and run in the Harvey office. This compositional model showed that an earlier spike in oil production actually occurs due to compartmentalized high oil saturation regions. It is due to this that further reservoir characterization is now being performed.

CO2PM OIL PREDICTION

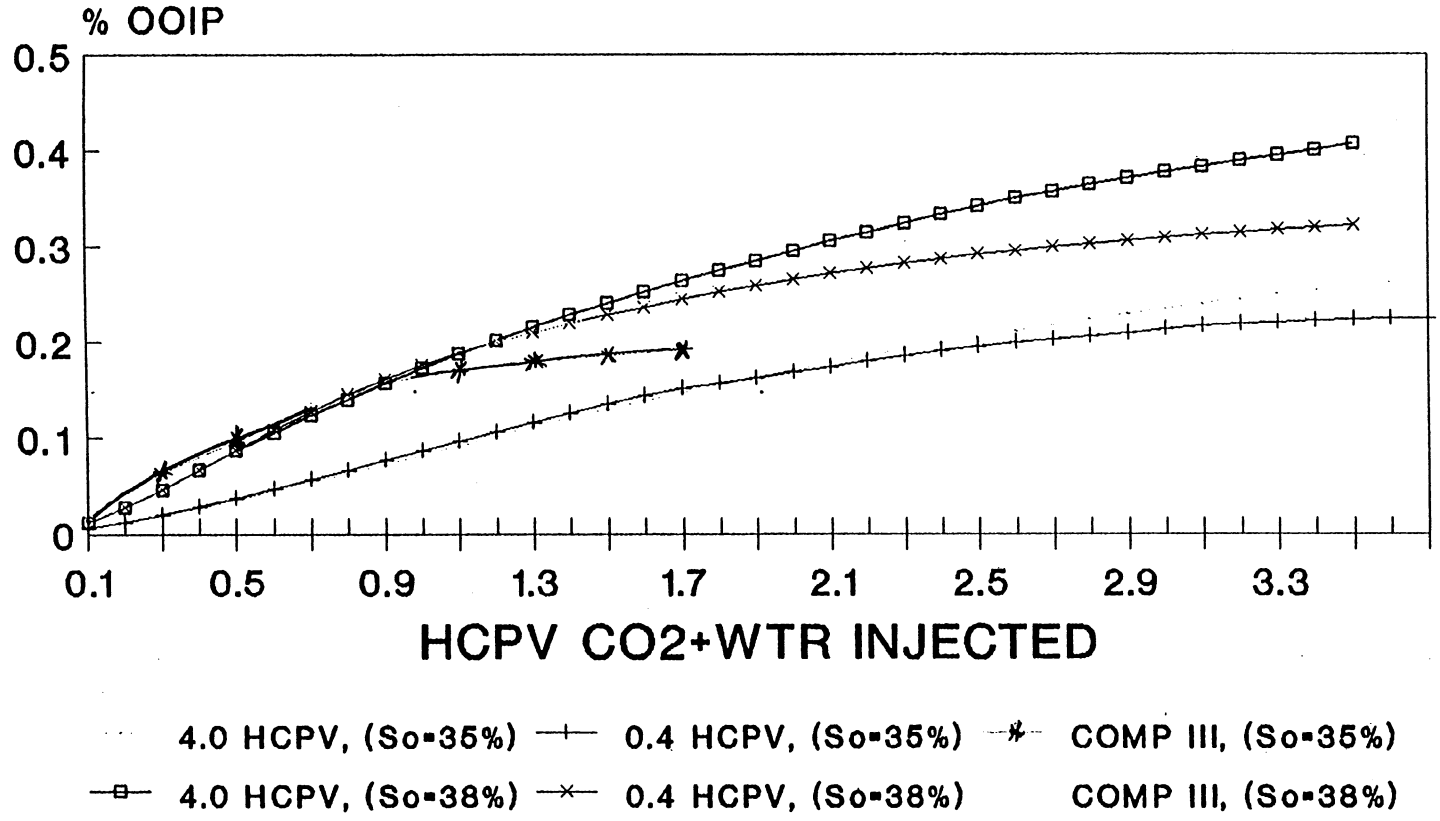
OIL SATURATION EFFECTS

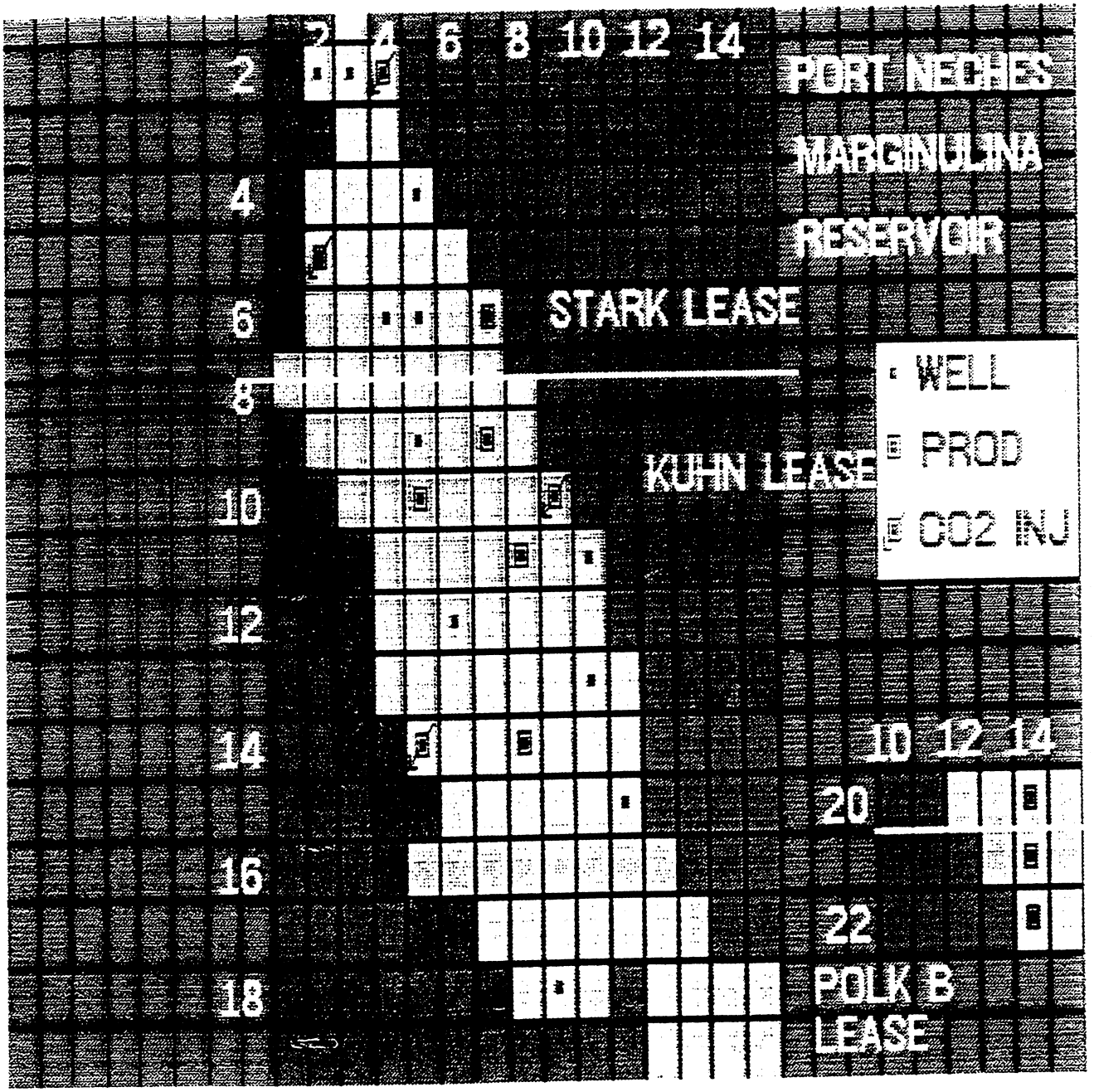


CO2PM OIL YIELD PREDICTIONS



CO2PM OIL PREDICTION
OIL SATURATION EFFECTS




2 4 6 8 10 12 14
2
4
6
8
10
12
14
16
18
PORT NECHES
MARGINULINA
RESERVOIR
STARK LEASE
KUHN LEASE
WELL
PROD
CO2 INJ
10 12 14
20
22
POLK B
LEASE

```
TITLE COMP3 PORT NECHES RESERVOIR SIMULATION  SEPTEMBER, 1991
TITLE 15X22X2 3D RESERVOIR WITH INITIAL WATER/OIL CONTACT AT 6000 FT
TITLE 6 COMPONENTS. CO2 IS 6TH COMPONENT IN MODEL.
TITLE RELATIVE PERMEABILITY COORELATIONS USED FOR ROCK PROPERTIES.
TITLE 0    -11315 DAYS:       DEPLETION  HISTORY MATCH PERIOD
TITLE 11315-21900 DAYS:       WATERFLOOD HISTORY MATCH PERIOD
TITLE 21900-27500 DAYS:       CO2 INJECTION PREDICTION PERIOD.
;
; ** KVTABLE GENERATED USING CCEXP (WE RECOMMEND CVEXP).
;
NX 15  NY 22  NZ 2
PERCOLATION OFF
ARRAYS OFF ; TURN OFF ALL ARRAY OUTPUT IN INITIALIZATION
;
CW .00000301 CR .000006  BWI 1.022   DWB  67.2    VISW .4265   TO 165.
PSTD  14.65
; **NUMBER OF COMPONENTS**  CP1=COMPONENT 6, TRACER USED
NC 6          ; ADD CO2 AS COMPONENT 6
;TRACER 6 2
;EXPANSION
;  GENERATE K-VALUE PRESSURE TABLE USING CONSTANT COMPOSITION EXPANSION
;  KVTABLE (PG 4-42) PEXP TABLE# BUBBLE PT PRESSURE
;DYNAMIC
;PRESSURE
KVTABLE 1
PSWITCH 1 2302.9
OILEXP 1
PEXP 1 2302.9
ZEXP 1 .5  .0299 .07  .2  .2  .0001  ; ADD Z FACTOR FOR CO2 (ADD TO 1.)
;
; EOS PVT DATA
NAME C1 C3 C6 C10  PC1  CP1  ; ADD CO2 NAME AS CP1
PR
PCRIT 667.8 616.3  436.9  304.0   190.5   1070.0   ;ADD CO2 PROPERTIES
TCRIT 343.0  665.7  913.4 1111.8  1297.5  547.8
MW    16.04  44.12  86.18  142.29 225.00  44.01
PCHOR 77  150.3 271 431.0  671.866  79.7
AC   .013  .1524  .3007 .4885  .7000  .225
ZCRIT .29  .277  .264  .257  .23  .2749
OMEGA .45746339  .45723550  .45723550  .45723550  .46393726 .42748
OMEGB .07781338  .07779610  .07779610  .07779610  .07869649 .08190
REFD  .300 .5077 .6163 .61890 .60220670  .777
TBOIL -258.68 -43.73  155.73  345.42  545.2922  -109.2
REFT    60.00  60.00  155.73  345.42  545.2922  68
CRITZ .29    .2770  .2640  .2570  .2447907  .2749
BIN  .00 .00 .0 .0510079  0.0 0.0 0.005 0.0 0.0 0.0
     .00 .00 .00 .00 .00 ;
; USE ANALYTICAL KR, PC OPTION AND VERT. EQ. PC OPTION.
SORG .30  SORW  .30  SGC .05   SOINIT 0.0
SATWO ROCK=1  ZPC
; SW       KRW        KROW
0.20       0.00000    0.83000
0.25       0.00004    0.70363
0.30       0.00049    0.57768
0.35       0.00216    0.45828
0.40       0.00620    0.34883
0.45       0.01405    0.25170
0.50       0.02742    0.16862
0.55       0.04826    0.10084
0.60       0.07875    0.04933
0.65       0.12128    0.01500
0.70       0.17847    0.00000
0.80       0.34825    0.00000
1.00       1.00000    0.00000
```

```
SATGO ROCK=1   ZPC    SGR=0.00
; SLIQ     KROG       KRG        ; SLIQ=SO+SWC
0.20       0.00000    0.83000
0.25       0.00000    0.72302
0.30       0.00000    0.62342
0.40       0.00515    0.40207
0.50       0.02276    0.24053
0.60       0.06536    0.12382
0.70       0.14813    0.05009
0.80       0.28905    0.01265
0.90       0.50868    0.00074
1.00       0.83000    0.00000
;
; READ RESERVOIR GRID-PROPERTY DESCRIPTION DATA.
DX CON 300.0
DY YVAR  6*300.0  2*120.0  14*300.0
; READ GROSS THICKNESS, FT.
DZ VALUE
; LAYER 1 GROSS THICKNESS
;1  2  3  4  5  6  7  8  9 10 11 12 13 14 15
10 10 10 00 00 00 00 00 00 00 00 00 00 00 00
10 10 10 10 00 00 00 00 00 00 00 00 00 00 00
10 10 10 10 00 00 00 00 00 00 00 00 00 00 00
10 10 10 10 10 00 00 00 00 00 00 00 00 00 00
10 10 10 10 10 10 00 00 00 00 00 00 00 00 00
10 10 10 10 10 10 10 00 00 00 00 00 00 00 00
10 10 10 10 10 10 10 00 00 00 00 00 00 00 00
10 10 10 10 10 10 10 10 00 00 00 00 00 00 00
10 10 10 10 10 10 10 10 10 00 00 00 00 00 00
10 10 10 10 10 10 10 10 10 10 00 00 00 00 00
10 10 10 10 10 10 10 10 10 10 10 00 00 00 00
00 10 10 10 10 10 10 10 10 10 10 00 00 00 00
00 00 10 10 10 10 10 10 10 10 00 00 00 00 00
00 00 10 10 10 10 10 10 10 10 10 00 00 00 00
00 00 00 10 10 10 10 10 10 10 10 00 00 00 00
00 00 00 10 10 10 10 10 10 10 10 10 10 00 00
00 00 00 00 10 10 10 10 10 10 10 10 10 00 00
00 00 00 00 00 00 10 10 10 10 10 10 10 10 10
00 00 00 00 00 00 00 00 00 00 00 10 10 10 10
00 00 00 00 00 00 00 00 00 00 00 00 10 10 10
00 00 00 00 00 00 00 00 00 00 00 00 00 10 10
; LAYER 2 GROSS THICKNESS
;1  2  3  4  5  6  7  8  9 10 11 12 13 14 15
23 23 23 00 00 00 00 00 00 00 00 00 00 00 00
23 17 17 17 00 00 00 00 00 00 00 00 00 00 00
23 23 23 23 00 00 00 00 00 00 00 00 00 00 00
23 23 23 23 22 00 00 00 00 00 00 00 00 00 00
23 18 23 23 23 23 00 00 00 00 00 00 00 00 00
23 23 23 13 16 23 26 00 00 00 00 00 00 00 00
23 23 23 23 23 23 23 00 00 00 00 00 00 00 00
23 23 23 23 23 23 23 23 00 00 00 00 00 00 00
23 23 23 23 16 23 22 23 00 00 00 00 00 00 00
23 10 23 23 14 23 23 23 20 00 00 00 00 00 00
23 23 23 23 23 23 23 28 23 10 00 00 00 00 00
00 23 23 23 23 15 23 23 23 23 00 00 00 00 00
00 00 23 23 23 23 23 23 23 23 00 00 00 00 00
00 00 23 23 23 23 23 24 23 23 23 00 00 00 00
00 00 00 23 20 23 23 23 23 23 10 00 00 00 00
00 00 00 23 23 23 23 23 23 23 23 23 00 00 00
00 00 00 00 23 23 23 23 23 23 23 23 23 00 00
00 00 00 00 00 00 23 23 14 23 23 23 23 23 23
00 00 00 00 00 00 00 00 00 00 00 23 23 23 23
00 00 00 00 00 00 00 00 00 00 00 18 23 20 23
00 00 00 00 00 00 00 00 00 00 00 00 23 23 23
00 00 00 00 00 00 00 00 00 00 00 00 00 23 23
```

```
; NO NET THICKNESS FULL ARRAY, 15X22X2 VALUES
; READ DEPTH TO TOP OF SAND, FT., 15X22 VALUES.
HTOP LAYER
6100 6000 5970 9999 9999 9999 9999 9999 9999 9999
9999 9999 9999 9999 9999
; J=2
6000 5971 5950 5945 9999 9999 9999 9999 9999 9999
9999 9999 9999 9999 9999
6025 6000 5975 5950 9999 9999 9999 9999 9999 9999
9999 9999 9999 9999 9999
; J=4
6025 5975 5900 5900 5950 9999 9999 9999 9999 9999
9999 9999 9999 9999 9999
6000 5950 5875 5875 5925 5950 9999 9999 9999 9999
9999 9999 9999 9999 9999
; J=6
6000 5900 5850 5840 5930 5900 5898 9999 9999 9999
9999 9999 9999 9999 9999
5975 5900 5850 5835 5875 5860 5875 9999 9999 9999
9999 9999 9999 9999 9999
; J=8
5990 5900 5840 5835 5850 5850 5900 5925 9999 9999
9999 9999 9999 9999 9999
6000 5950 5890 5850 5828 5835 5902 5950 9999 9999
9999 9999 9999 9999 9999
; J=10
6050 6000 5950 5890 5837 5800 5850 5925 5900 9999
9999 9999 9999 9999 9999
6100 6050 6000 5900 5825 5790 5850 5920 5900 5880
9999 9999 9999 9999 9999
; J=12
9999 6100 6000 5925 5850 5790 5825 5850 5875 5870
9999 9999 9999 9999 9999
9999 9999 6050 5950 5900 5850 5825 5800 5800 5800
5850 9999 9999 9999 9999
; J=14
9999 9999 6050 6000 5975 5900 5825 5750 5750 5800
5900 9999 9999 9999 9999
9999 9999 9999 6075 6000 5925 5840 5780 5740 5790
5875 9999 9999 9999 9999
; J=16
9999 9999 9999 6050 5950 5875 5840 5775 5775 5850
5850 5850 9999 9999 9999
9999 9999 9999 9999 6100 6000 5950 5890 5840 5790
5825 5850 5850 9999 9999
; J=18
9999 9999 9999 9999 9999 9999 6000 5950 5925 5900
5850 5850 5850 5850 5850
9999 9999 9999 9999 9999 9999 9999 9999 9999 9999
9999 5900 5900 5880 5950
; J=20
9999 9999 9999 9999 9999 9999 9999 9999 9999 9999
9999 5933 5900 5898 5900
9999 9999 9999 9999 9999 9999 9999 9999 9999 9999
9999 9999 5900 5868 5880
; J=22
9999 9999 9999 9999 9999 9999 9999 9999 9999 9999
9999 9999 9999 5900 5900
;
; READ POROSITY FULL ARRAY, 15X22X3 VALUES.
PHI VALUE ;  LAYER1 AND LAYER2
; J=1
15*.3 ;.30 .30 .30 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00
15*.3 ;.30 .30 .30 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00
; J=2
15*.3;.30 .30 .30 .30 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00
```

```
15*.3;.30 .30 .30 .30 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00
; J=3
15*.3;.30 .30 .30 .30 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00
15*.3;.30 .30 .30  30 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00
; J=4
15*.3;.30 .30 .30 .30 .30 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00
15*.3;.30 .30 .30 .30 .30 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00
; J=5
15*.3;.30 .30 .30 .30 .30 .30 .00 .00 .00 .00 .00 .00 .00 .00 .00
15*.3;.30 .30 .30 .30 .30 .30 .00 .00 .00 .00 .00 .00 .00 .00 .00
; J=6
15*.3;.30 .30 .30 .30 .30 .30 .30 .00 .00 .00 .00 .00 .00 .00 .00
15*.3;.30 .30 .30 .30 .30 .30 .30 .00 .00 .00 .00 .00 .00 .00 .00
; J=7
15*.3;.30 .30 .30 .30 .30 .30 .30 .00 .00 .00 .00 .00 .00 .00 .00
15*.3;.30 .30 .30 .30 .30 .30 .30 .00 .00 .00 .00 .00 .00 .00 .00
; J=8
15*.3;.30 .30 .30 .30 .30 .30 .30 .30 .00 .00 .00 .00 .00 .00 .00
15*.3;.30 .30 .30 .30 .30 .30 .30 .30 .00 .00 .00 .00 .00 .00 .00
; J=9
15*.3;.30 .30 .30 .30 .30 .30 .30 .30 .00 .00 .00 .00 .00 .00 .00
15*.3;.30 .30 .30 .30 .30 .30 .30 .30 .00 .00 .00 .00 .00 .00 .00
; J=10
15*.3;.30 .30 .30 .30 .30 .30 .30 .30 .30 .00 .00 .00 .00 .00 .00
15*.3;.30 .30 .30 .30 .30 .30 .30 .30 .30 .00 .00 .00 .00 .00 .00
; J=11
15*.3;.30 .30 .30 .30 .30 .30 .30 .30 .30 .30 .00 .00 .00 .00 .00
15*.3;.30 .30 .30 .30 .30 .30 .30 .30 .30 .30 .00 .00 .00 .00 .00
; J=12
15*.3;.00 .30 .30 .30 .30 .30 .30 .30 .30 .30 .00 .00 .00 .00 .00
15*.3;.00 .30 .30 .30 .30 .30 .30 .30 .30 .30 .00 .00 .00 .00 .00
; J=13
15*.3;.00 .00 .30 .30 .30 .30 .30 .30 .30 .30 .00 .00 .00 .00 .00
15*.3;.00 .00 .30 .30 .30 .30 .30 .30 .30 .30 .00 .00 .00 .00 .00
; J=14
15*.3;.00 .00 .30 .30 .30 .30 .30 .30 .30 .30 .30 .00 .00 .00 .00
15*.3;.00 .00 .30 .30 .30 .30 .30 .30 .30 .30 .30 .00 .00 .00 .00
; J=15
15*.3;.00 .00 .00 .30 .30 .30 .30 .30 .30 .30 .30 .00 .00 .00 .00
15*.3;.00 .00 .00 .30 .30 .30 .30 .30 .30 .30 .30 .00 .00 .00 .00
; J=16
15*.3;.00 .00 .00 .30 .30 .30 .30 .30 .30 .30 .30 .30 .00 .00 .00
15*.3;.00 .00 .00 .30 .30 .30 .30 .30 .30 .30 .30 .30 .00 .00 .00
; J=17
15*.3;.00 .00 .00 .00 .30 .30 .30 .30 .30 .30 .30 .30 .30 .00 .00
15*.3;.00 .00 .00 .00 .30 .30 .30 .30 .30 .30 .30 .30 .30 .00 .00
; J=18
15*.3;.00 .00 .00 .00 .00 .00 .30 .30 .30 .30 .30 .30 .30 .30 .30
15*.3;.00 .00 .00 .00 .00 .00 .30 .30 .30 .30 .30 .30 .30 .30 .30
; J=19
15*.3;.00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .30 .30 .30 .30
15*.3;.00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .30 .30 .30 .30
; J=20
15*.3;.00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .30 .30 .30 .30
15*.3;.00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .30 .30 .30 .30
; J=21
15*.3;.00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .30 .30 .30
15*.3;.00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .30 .30 .30
; J=22
15*.3;.00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .30 .30
15*.3;.00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .00 .30 .30
;
; READ KX, KY, KZ ARRAY VALUES (MD)
KX CON 750
KY CON 750
KZ CON 375
```

```
;
;POTAQ  ;  POT  AQUIFER  (RB/PSI)
;AQCOEF CON 0
;MOD 1 1  1 22  1 2  = 100
;
SSAQ  ; STEADY-STATE AQUIFER  (RB/PSI-DAY)
AQCOEF CON 0
MOD 1 1  1 22  1 2 = 0.01125
; IF GOC EXISTS, HINIT=GOC AND PINIT=PSAT
EQUIL  OIL
HINIT 5800.  PINIT 2714.65  PSAT 2300  WOC 6000.  GOC 5700.
;ZTRACER 1 0
Z .5 .0299 .07 .2 .2 .0001
;SWINIT = 0.68
RUN
; END OF INITIAL DATA
; A17OUT 3 AND A17FREQ ARE EXPLAINED IN APPENDIX B
A17OUT   3
A17FREQ  1
;
; START OF RECURRENT DATA
WELL 1  I 14  J 20  PERF 1  1  2  GC 1   ; K6 - prod
WELL 2  I  5  J  9  PERF 2  1  2  GC 1   ; K13
WELL 3  I  7  J  9  PERF 3  1  2  GC 1   ; K14 - prod
WELL 4  I 10  J 11  PERF 4  1  2  GC 1   ; K15
WELL 5  I  9  J 10  PERF 5  1  2  GC 1   ; K15R - inj
WELL 6  I 10  J 13  PERF 6  1  2  GC 1   ; K16
WELL 7  I  9  J 18  PERF 7  1  2  GC 1   ; K17
WELL 8  I  5  J 10  PERF 8  1  2  GC 1   ; K33 - prod
WELL 9  I  8  J 11  PERF 9  1  2  GC 1   ; K36 - prod
WELL 10 I  8  J 14  PERF 10 1  2  GC 1   ; K38 - prod
WELL 11 I 11  J 15  PERF 11 1  2  GC 1   ; K42
WELL 12 I  6  J 12  PERF 12 1  2  GC 1   ; K46
WELL 13 I  6  J 12  PERF 13 1  2  GC 1   ; K53
WELL 14 I  5  J 14  PERF 14 1  2  GC 1   ; K54 - inj
WELL 15 I  7  J 17  PERF 15 1  2  GC 1   ; K55
WELL 16 I  2  J  5  PERF 16 1  2  GC 1   ; S6
WELL 17 I  5  J  6  PERF 17 1  2  GC 1   ; S7
WELL 18 I  7  J  6  PERF 18 1  2  GC 1   ; S8 - prod
WELL 19 I  5  J  4  PERF 19 1  2  GC 1   ; S9
WELL 20 I  4  J  2  PERF 20 1  2  GC 1   ; S10 - inj
WELL 21 I  3  J  2  PERF 21 1  2  GC 1   ; S26
WELL 22 I  4  J  6  PERF 22 1  2  GC 1   ; S29
WELL 23 I  2  J  2  PERF 23 1  2  GC 1   ; S35
WELL 24 I  2  J  5  PERF 24 1  2  GC 1   ; S50 - inj
WELL 25 I 14  J 21  PERF 25 1  2  GC 1   ; P2 - prod
WELL 26 I 14  J 22  PERF 26 1  2  GC 1   ; P50 - prod
;
BHP 1  30
BHP 2  30
BHP 3  30
BHP 4  30
BHP 5  30
BHP 6  30
BHP 7  30
BHP 8  30
BHP 9  30
BHP 10 30
BHP 11 30
BHP 12 30
BHP 13 30
BHP 14 30
BHP 15 30
BHP 16 30
BHP 17 30
BHP 18 30
```

during CO2 flooding

```
BHP 19 30
BHP 20 30
BHP 21 30
BHP 22 30
BHP 23 30
BHP 24 30
BHP 25 30
BHP 26 30
;
; KH (PG 5-22)
KH 1     7500     15000
KH 2     7500     12000
KH 3     7500     16500
KH 4     7500      7500
KH 5     7500     15000
KH 6     7500     17250
KH 7     7500     10500
KH 8     7500     10500
KH 9     7500     21000
KH 10    7500     18000
KH 11    7500      7500
KH 12    7500     11250
KH 13    7500     11250
KH 14    7500     17250
KH 15    7500     17250
KH 16    7500     13500
KH 17    7500     12000
KH 18    7500     19500
KH 19    7500     16500
KH 20    7500     12750
KH 21    7500     12750
KH 22    7500      9750
KH 23    7500     12750
KH 24    7500     13500
KH 25    7500     17250
KH 26    7500     17250
;
; START PRIMARY PRODUCTION
;
PROD 1   STBOIL      NAME   K6
PROD 2   STBOIL      NAME   K13
PROD 3   STBOIL      NAME   K14
PROD 4   STBOIL      NAME   K15
PROD 5   STBOIL      NAME   K15R
PROD 6   STBOIL      NAME   K16
PROD 7   STBOIL      NAME   K17
PROD 8   STBOIL      NAME   K33
PROD 9   STBOIL      NAME   K36
PROD 10  STBOIL      NAME   K38
PROD 11  STBOIL      NAME   K42
PROD 12  STBOIL      NAME   K46
PROD 13  STBOIL      NAME   K53
PROD 14  STBOIL      NAME   K54
PROD 15  STBOIL      NAME   K55
PROD 16  STBOIL      NAME   S6
PROD 17  STBOIL      NAME   S7
PROD 18  STBOIL      NAME   S8
PROD 19  STBOIL      NAME   S9
PROD 20  STBOIL      NAME   S10
PROD 21  STBOIL      NAME   S26
PROD 22  STBOIL      NAME   S29
PROD 23  STBOIL      NAME   S35
PROD 24  STBOIL      NAME   S50
PROD 25  STBOIL      NAME   P2
PROD 26  STBOIL      NAME   P50
;
```

```
; Q  WELL TARGET RATES
Q 1 245   Q 16 26   Q 25 253
;ENDJOB
TIME 1825 ; 1934 THRU 1938 (DATA ABOVE)
Q 1 89  Q 2 20  Q 3 44  Q 4 8  Q 6 1  Q 7 48  Q 16 32
Q 17 40 Q 18 40 Q 19 17 Q 20 44 Q 25 39
TIME 3650 ; 1939 THRU 1943 (DATA ABOVE)
Q 1 51  Q 2 0   Q 3 62  Q 4 7  Q 6 0  Q 7 44  Q 16 34
Q 17 40 Q 18 84 Q 19 38 Q 20 55 Q 25 43
TIME 5475 ; 1944 THRU 1948 (DATA ABOVE)
Q 1 33  Q 3 80  Q 4 0   Q 7 0  Q 16 0 Q 17 37 Q 18 85
Q 19 31 Q 20 40 Q 25 38
TIME 7300 ; 1949 THRU 1953 (DATA ABOVE)
Q 1 20  Q 3 48  Q 17 38 Q 18 29 Q 19 36 Q 20 28 Q 25 50
; RESTART 2
TIME 9125 ; 1954 THRU 1958 (DATA ABOVE)
Q 1 8   Q 3 52  Q 8 26  Q 9 5   Q 17 32 Q 18 35 Q 19 49
Q 20 45 Q 22 2 Q 25 25
; RESTART 2
TIME 10950; 1959 THRU 1963 (DATA ABOVE)
; WATERFLOOD STARTS DURING 1965 ( BHP = 80-100 PSI)
INJ  7  STBW        NAME   K17   BHP  7  4000
INJ  20 STBW        NAME   S10   BHP 20  4000
Q 7 296  Q 20 471
Q 1 0   Q 3 37  Q 6 14  Q 8 29  Q 9  27 Q 11 19 Q 17 0
Q 18 30 Q 19 24 Q 22 25 Q 25 9
TIME 12775; 1964 THRU 1968 (DATA ABOVE)
Q 7 342  Q 20 371
Q 3 15  Q 6 0   Q 8 83  Q 9 16 Q 11 13  Q 12 18 Q 18 31
Q 19 0  Q 22 64 Q 25 7
TIME 14600; 1969 THRU 1973 (DATA ABOVE)
INJ  11 STBW        NAME   K42   BHP  11  4000
Q 7 70  Q 20  37  Q 11  228
Q 1 17  Q 3 0   Q 5 16  Q 6 10 Q 8 53   Q 9 0
Q 12 0  Q 13 13 Q 18 9  Q 22 0 Q 25 0
TIME 16425; 1974 THRU 1978 (DATA ABOVE)
Q 7 162 Q 20 0    Q 11  815
Q 1 14  Q 5 11  Q 6 6   Q 8 26 Q 13 7   Q 18 45
TIME 18250; 1979 THRU 1983 (DATA ABOVE)
Q 7 491 Q 11 994
Q 1 21  Q 5 26  Q 6 2   Q 8 35 Q 10 17  Q 13 23 Q 18 38
TIME 20075; 1984 THRU 1988 (DATA ABOVE)
Q 7 500 Q 11 1000
Q 1 10  Q 5 15  Q 6 0   Q 8 15 Q 10 15  Q 13 0 Q 18 15
RESTART 2
TIME 21170; 1989 THRU 1991 (DATA ABOVE)
BHP 7 3600  BHP 11 3600
Q 7 5000  Q 11 5000
Q 1 0  Q 5 0  Q 6 0  Q 8 0  Q 10 0  Q 18 0
TIME 21535 ; INJECT 10000 BWPD DURING 1992
Q 7 5000  Q 11 5000
TIME 21900 ; INJECT 10000 BWPD DURING 1993
Q 7 5000  Q 11 5000
TIME 22265 ; INJECT 20000 BWPD DURING 1994
; PRINT END-OF-RUN WELL SUMMARIES FOR ALL WELLS.
; SUMMARY 1 26
; START CO2 GAS INJECTION
;
; ACTIVATE EOS USAGE FOR GAS INJECTION GLOBALLY
OVER KVTYPE   1 15 1 22 1 2  = 0
;
; TURN OFF RESTART WRITE, OUTPUT PRINT.
;RESTART 0  TFREQ -1  WFREQ -1  AFREQ -1
PROD 1  RBTOTAL     NAME   K6     GC 1     BHP 1 3400
PROD 2  RBTOTAL     NAME   K13    GC 1     BHP 2 3400
PROD 3  RBTOTAL     NAME   K14    GC 1     BHP 3 3400
```

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PROD 4   RBTOTAL      NAME   K15     GC 1     BHP 4 3400
INJ  5   MCFGAS       NAME   K15R    GC 1     BHP 5 4000
PROD 6   RBTOTAL      NAME   K16     GC 1     BHP 6 3400
PROD 7   RBTOTAL      NAME   K17     GC 1     BHP 7 3400
PROD 8   RBTOTAL      NAME   K33     GC 1     BHP 8 3400
PROD 9   RBTOTAL      NAME   K36     GC 1     BHP 9 3400
PROD 10  RBTOTAL      NAME   K38     GC 1     BHP 10 3400
PROD 11  RBTOTAL      NAME   K42     GC 1     BHP 11 3400
PROD 12  RBTOTAL      NAME   K46     GC 1     BHP 12 3400
PROD 13  RBTOTAL      NAME   K53     GC 1     BHP 13 3400
INJ  14  MCFGAS       NAME   K54     GC 1     BHP 14 4000
PROD 15  RBTOTAL      NAME   K55     GC 1     BHP 15 3400
PROD 16  RBTOTAL      NAME   S6      GC 1     BHP 16 3400
PROD 17  RBTOTAL      NAME   S7      GC 1     BHP 17 3400
PROD 18  RBTOTAL      NAME   S8      GC 1     BHP 18 3400
PROD 19  RBTOTAL      NAME   S9      GC 1     BHP 19 3400
INJ  20  MCFGAS       NAME   S10     GC 1     BHP 20 4000
PROD 21  RBTOTAL      NAME   S26     GC 1     BHP 21 3400
PROD 22  RBTOTAL      NAME   S29     GC 1     BHP 22 3400
PROD 23  RBTOTAL      NAME   S35     GC 1     BHP 23 3400
INJ  24  MCFGAS       NAME   S50     GC 1     BHP 24 4000
PROD 25  RBTOTAL      NAME   P2      GC 1     BHP 25 3400
PROD 26  RBTOTAL      NAME   P50     GC 1     BHP 26 3400
;
Q 3 9000 Q 8  9000 Q 9  9000 Q 13 9000 Q 18 9000 Q 17 9000
Q 19 9000
; Q 5 1100 Q 14 1100 Q 20 1100 Q 24 1000
ITARG 1 RES G 15000
MAKEUP 1 4300
GCMF 1  0 0 0 0 0 1
;
INJMF 5      5*0.0 1.0; INJECTION OF ALL CO2 (1ST 5 COMPONENTS =0)
INJMF 14     5*0.0 1.0  ; 6TH COMPONENT = 100%
INJMF 20     5*0.0 1.0
INJMF 24     5*0.0 1.0
;
TIME 22995
Q 1 1000 Q 25 1000 Q 26 1000 Q 3 1000 Q 8 1000 Q 9 1000 Q 10 1000
Q 18 1000
; Q 5 3000 Q 14 3000
TIME 23360
Q 1 1000 Q 25 1000 Q 26 1000 Q 3 1000 Q 8 1000 Q 9 1000 Q 10 1000
Q 18 1000
; Q 5 4000 Q 14 4000
TIME 23725
DTMIN 10. ; FROM RUN EXPERIENCE
Q 1 1000 Q 25 1000 Q 26 1000 Q 3 1000 Q 8 1000 Q 9 1000 Q 10 1000
Q 18 1000
; Q 5 5000 Q 14 5000
DTAUTO 5.
A17FREQ  1
;
TIME 30000
;ARRAYS ON EOS
; END OF EXTENDED HISTORY MATCH PERIOD
ENDJOB
```

OIL PRODUCTION HISTORY FIGURES

Attached are production histories for both the large waterflood fault block and the small weak aquifer fault block.

WATERFLOOD PRODUCTION HISTORY

		BO	BW	MCF	CUM OIL	CUM WTR	CUM GAS	BOPD	BWPD	MCFPD	YEAR	PRESSURE	GOR
TOTALS	1934	61183	0	12099	61183	0	12099	168	0	33	0	2700	198
	1935	253076	53216	163536	314259	53216	175635	693	146	448	1		646
	1936	221123	28852	678100	535382	82068	853735	606	79	1858	2		3067
	1937	202410	6027	354977	737792	88095	1208712	555	17	973	3		1754
	1938	218372	5394	228018	956164	93489	1436730	598	15	625	4		1044
	1939	171452	1492	318061	1127616	94981	1754791	470	4	871	5		1855
	1940	170771	1680	355377	1298387	96661	2110168	468	5	974	6	1500	2081
	1941	173791	2106	235447	1472178	98767	2345615	476	6	645	7	1340	1355
	1942	109325	8063	139002	1581503	106830	2484617	300	22	381	8	1240	1271
	1943	144967	8191	89924	1726470	115021	2574541	397	22	246	9	1200	620
	1944	172423	34256	88616	1898893	149277	2663157	472	94	243	10	1150	514
	1945	179092	42690	93779	2077985	191967	2756936	491	117	257	11	1090	524
	1946	180667	38370	81596	2258652	230337	2838532	495	105	224	12	1040	452
	1947	161951	64153	70787	2420603	294490	2909319	444	176	194	13	980	437
	1948	138900	40429	56536	2559503	334919	2965855	381	111	155	14	920	407
	1949	124774	15495	46568	2684277	350414	3012423	342	42	128	15	860	373
	1950	114291	28854	48081	2798568	379268	3060504	313	79	132	16	810	421
	1951	134405	43098	60695	2932973	422366	3121199	368	118	166	17	750	452
	1952	134075	63366	87284	3067048	485732	3208483	367	174	239	18	700	651
	1953	117814	84891	144601	3184862	570623	3353084	323	233	396	19	640	1227
	1954	100739	91141	89542	3285601	661764	3442626	276	250	245	20	570	889
	1955	76804	106126	71122	3362405	767890	3513748	210	291	195	21		926
	1956	74366	77332	42176	3436771	845222	3555924	204	212	116	22		567
	1957	103867	156039	55536	3540638	1001261	3611460	285	428	152	23		535
	1958	100311	140039	81781	3640949	1141300	3693241	275	384	224	24		815
	1959	107226	158509	81042	3748175	1299809	3774283	294	434	222	25		756
	1960	111465	132054	85817	3859640	1431863	3860100	305	362	235	26		770
	1961	103925	108957	79631	3963565	1540820	3939731	285	299	218	27		766
	1962	97990	61519	90588	4061555	1602339	4030319	268	169	248	28		924
	1963	78801	47674	62160	4140356	1650013	4092479	216	131	170	29		789
	1964	65693	37487	34803	4206049	1687500	4127282	180	103	95	30	100	530
	1965	78623	41792	33048	4284672	1729292	4160330	215	114	91	31		420
	1966	72982	80261	47932	4357654	1809553	4208262	200	220	131	32		657
	1967	58376	120070	8382	4416030	1929623	4216644	160	329	23	33		144
	1968	75023	67051	5507	4491053	1996674	4222151	206	184	15	34		73
	1969	93524	19153	6225	4584577	2015827	4228376	256	52	17	35		67
	1970	93204	45959	9298	4677781	2061786	4237674	255	126	25	36		100
	1971	75381	28041	7143	4753162	2089827	4244817	207	77	20	37		95
	1972	105422	81077	14268	4858584	2170904	4259085	289	222	39	38		135
	1973	55684	34268	373	4914268	2205172	4259458	153	94	1	39		7
	1974	18738	19903	13742	4933006	2225075	4273200	51	55	38	40		733
	1975	30927	25353	4216	4963933	2250428	4277416	85	69	12	41		136
	1976	60074	141788	25948	5024007	2392216	4303364	165	388	71	42		432
	1977	54231	164719	18182	5078238	2556935	4321546	149	451	50	43		335
	1978	51311	261282	7299	5129549	2818217	4328845	141	716	20	44		142
	1979	44533	319060	4348	5174082	3137277	4333193	122	874	12	45		98
	1980	50950	276335	10836	5225032	3413612	4344029	140	757	30	46		213
	1981	49865	322190	3382	5274897	3735802	4347411	137	883	9	47		68
	1982	30150	263290	4365	5305047	3999092	4351776	83	721	12	48		145
	1983	21081	315407	5973	5326128	4314499	4357749	58	864	16	49		283
	1984	25871	380754	7760	5351999	4695253	4365509	71	1043	21	50		300
	1985	61019	513216	19064	5413018	5208469	4384573	167	1406	52	51		312
	1986	77508	724858	18289	5490526	5933327	4402862	212	1986	50	52		236
	1987	78335	918902	8216	5568861	6852229	4411078	215	2518	23	53		105

1988	52017	775872	5959	5620878	7628101	4417037	143	2126	16	54	115
1989	34652	688327	7285	5655530	8316428	4424322	95	1886	20	55	210
1990	28276	663852	9797	5683806	8980280	4434119	77	1819	27	56	346

FAULT BLOCK V PRODUCTION HISTORY

		BO	BW	MCF	CUM OIL	CUM WTR	CUM GAS	So	WTR CUT	BHP	Uo	Kw/Ko	BOPD	BWPD	MCFPD	YEAR	PRESSURE	GOR
POLK B5	1935	14064	287	5933	14064	287	5933	0.792	0.02	2700	0.62	0.013	39	1	16	0	2700	422
	1936	26953	1612	21381	41017	1899	27314	0.777	0.06	2640	0.62	0.039	74	4	59	1	2640	666
	1937	13152	6545	5731	54169	8444	33045	0.769	0.33	2480	0.63	0.322	36	18	16	2	2480	610
	1938	11081	1003	5918	65250	9447	38963	0.763	0.08	2340	0.66	0.056	30	3	16	3	2340	597
	1939	18332	2260	23215	83582	11707	62178	0.752	0.11	2200	0.68	0.074	50	6	64	4	2200	744
	1940	22547	1275	23829	106129	12982	86007	0.740	0.05	2050	0.71	0.032	62	3	65	5	2050	810
	1941	16304	1417	24874	122433	14399	110881	0.730	0.08	1900	0.75	0.047	45	4	68	6	1900	906
	1942	10169	884	12659	132602	15283	123540	0.725	0.08	1760	0.78	0.045	28	2	35	7	1760	932
	1943	17109	1851	18178	149711	17134	141718	0.715	0.10	1830	0.76	0.058	47	5	50	8	1830	947
	1944	19230	1698	17137	168941	18832	158855	0.704	0.08	1900	0.75	0.048	53	5	47	9	1900	940
	1945	20054	63	11683	188995	18895	170538	0.693	0.00	1900	0.75	0.002	55	0	32	10	1900	902
	1946	16476	915	5761	205471	19810	176299	0.683	0.05	1870	0.75	0.030	45	3	16	11	1870	858
	1947	17561	984	7093	223032	20794	183392	0.673	0.05	1900	0.75	0.030	48	3	19	12	1900	822
	1948	17512	327	9426	240544	21121	192818	0.663	0.02	1870	0.75	0.010	48	1	26	13	1870	802
	1949	20001	3922	21387	260545	25043	214205	0.652	0.16	1840	0.76	0.105	55	11	59	14	1840	822
	1950	12277	4031	5811	272822	29074	220016	0.645	0.25	1810	0.77	0.174	34	11	16	15	1810	806
	1951	14671	5030	15584	287493	34104	235600	0.637	0.26	1780	0.78	0.179	40	14	43	16	1780	819
	1952	19200	6422	7373	306693	40526	242973	0.626	0.25	1750	0.78	0.175	53	18	20	17	1750	792
	1953	19569	10070	6881	326262	50596	249854	0.615	0.34	1720	0.79	0.265	54	28	19	18	1720	766
	1954	19392	12860	9111	345654	63456	258965	0.603	0.40	1700	0.8	0.338	53	35	25	19	1700	749
	1955	19482	9720	21179	365136	73176	280144	0.592	0.33	1680	0.8	0.254	53	27	58	20		767
	1956	18407	7790	21786	383543	80966	301930	0.582	0.30	1660	0.81	0.213	50	21	60	21		787
	1957	19259	8746	13728	402802	89712	315658	0.571	0.31	1640	0.81	0.228	53	24	38	22		784
	1958	15993	11803	18948	418795	101515	334606	0.562	0.42	1620	0.82	0.367	44	32	52	23		799
	1959	13672	23583	9438	432467	125098	344044	0.554	0.63	1600	0.83	0.847	37	65	26	24		796
	1960	11186	19946	6023	443653	145044	350067	0.548	0.64	1580	0.83	0.875	31	55	17	25		789
	1961	8863	20233	5817	452516	165277	355884	0.543	0.70	1560	0.84	1.107	24	55	16	26		786
	1962	6429	15541	4407	458945	180818	360291	0.539	0.71	1540	0.84	1.173	18	43	12	27		785
	1963	3824	10209	2656	462769	191027	362947	0.537	0.73	1520	0.85	1.280	10	28	7	28		784
	1964	6822	16524	5450	469591	207551	368397	0.533	0.71	1500	0.85	1.161	19	45	15	29		785
	1965	9670	22675	10447	479261	230226	378844	0.528	0.70	1480	0.86	1.111	26	62	29	30		790
	1966	8348	18249	9800	487609	248475	388644	0.523	0.69	1460	0.87	1.024	23	50	27	31		797
	1967	10245	19025	9541	497854	267500	398185	0.517	0.65	1440	0.88	0.860	28	52	26	32		800
	1968	9834	39914	5720	507688	307414	403905	0.511	0.80	1420	0.88	1.879	27	109	16	33		796
	1969	7982	23578	1350	515670	330992	405255	0.507	0.75	1400	0.89	1.352	22	65	4	34		786
	1970	4912	18083	597	520582	349075	405852	0.504	0.79	1380	0.9	1.667	13	50	2	35		780
	1971	9924	21671	3372	530506	370746	409224	0.498	0.69	1360	0.91	0.978	27	59	9	36		771
	1972	6066	13624	1065	536572	384370	410289	0.495	0.69	1340	0.91	1.006	17	37	3	37		765
	1973	2574	7124	6	539146	391494	410295	0.493	0.73	1320	0.92	1.226	7	20	0	38		761
	1974	11074	46884	3963	550220	438378	414258	0.487	0.81	1300	0.93	1.855	30	128	11	39		753
	1975	6643	17329	2121	556863	455707	416379	0.483	0.72	1280	0.94	1.131	18	47	6	40		748
	1976	2045	8729	1516	558908	464436	417895	0.482	0.81	1260	0.95	1.831	6	24	4	41		748
	1977	3725	12596	5251	562633	477032	423146	0.480	0.77	1240	0.95	1.450	10	35	14	42		752
	1978	5382	17093	90	568015	494125	423236	0.477	0.76	1220	0.96	1.348	15	47	0	43		745
	1979	7499	18460	120	575514	512585	423356	0.473	0.71	1200	0.97	1.034	21	51	0	44		736
	1980	5367	17517	3590	580881	530102	426946	0.470	0.77	1180	0.98	1.357	15	48	10	45		735
	1981	5802	52163	878	586683	582265	427824	0.466	0.90	1160	0.99	3.701	16	143	2	46		729
	1982	5352	33301	106	592035	615566	427930	0.463	0.86	1140	1	2.536	15	91	0	47		723
	1983	3490	14884	122	595525	630450	428052	0.461	0.81	1120	1.01	1.721	10	41	0	48		719
	1984	2708	22183	193	598233	652633	428245	0.460	0.89	1100	1.01	3.305	7	61	1	49		716
	1985	3253	13048	177	601486	665681	428422	0.458	0.80	1080	1.02	1.602	9	36	0	50		712
	1986	3283	12820	176	604769	678501	428598	0.456	0.80	1060	1.03	1.545	9	35	0	51		709
	1987	3406	13951	77	608175	692452	428675	0.454	0.80	1040	1.04	1.605	9	38	0	52		705
	1988	1789	7233	6	609964	699685	428681	0.453	0.80	1020	1.05	1.569	5	20	0	53		703
	1989	4239	19242	733	614203	718927	429414	0.451	0.82	1000	1.05	1.762	12	53	2	54		699
	1990									995	1.06		10	42	5	55		ERR

Type or print only

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division

Form W-2
Rev. 4/1/83
483-046

API No. 42- 36130069

7. RRC District No. 3

Oil Well Potential Test, Completion or Recompletion Report, and Log

8. RRC Lease No. 03411

1. FIELD NAME (as per RRC Records or Wildcat): Port Neches
2. LEASE NAME: H.J. Kuhn Tr. 1
9. Well No.: 15-R
3. OPERATOR'S NAME (Exactly as shown on Form P-5, Organization Report): Texaco Inc.
RRC Operator No.: 844110
10. County of well site: Orange
4. ADDRESS: P.O. Box 8992, Corpus Christi, Texas, 78412
5. If Operator has changed within last 60 days, name former operator:
11. Purpose of filing: Initial Potential [ ] Retest [XX] Reclass [ ] Well record only (explain in Remarks) [ ]
6a. Location (Section, Block, and Survey): Seleston Sckavib A-431
6b. Distance and direction to nearest town in this county: 4 miles SE Bridge City, Texas
12. If workover or reclass, give former field (with reservoir) & gas ID or oil lease no. FIELD & RESERVOIR | GAS ID or OIL LEASE # | Oil - O Gas - G | WELL NO.
13. Type of electric or other log run: Induction-Elcetric, Correlation, Dip
14. Completion or recompletion date: 12-6-86

SECTION I: POTENTIAL TEST DATA IMPORTANT: Test should be for 24 hours unless otherwise specified in field rules.

15. Date of test	16. No. of hours tested	17. Production method (Flowing, Gas Lift, Jetting, Pumping—Size & Type of pump)	18. Choke size
12-6-86	24	Gas Lift	

	Oil - BBLS	Gas — MCF	Water - BBLS	Gas - Oil Ratio	Flowing Tubing Pressure
19. Production during Test Period ▶	105	40	645	381	PSI
20. Calculated 24-Hour Rate ▶	Oil - BBLS	Gas — MCF	Water — BBLS	Oil Gravity—API—60° 36.9°	Casing Pressure PSI

21. Was swab used during this test? Yes [ ] No [XX]
22. Oil produced prior to test (New & Reworked wells): 232 bbls.
23. Injection Gas—Oil Ratio: 1105

REMARKS:

Convert well from pumping to gas lift.

INSTRUCTIONS: File an original and one copy of the completed Form W-2 in the appropriate RRC District Office within 30 days after completing a well and within 10 days after a potential test. If an operator does not properly report the results of a potential test within the 10-day period, the effective date of the allowable assigned to the well will not extend back more than 10 days before the W-2 was received in the District Office. (Statewide Rules 16 and 51) To report a completion or recompletion, fill in both sides of this form. To report a retest, fill in only the front side.

WELL TESTER'S CERTIFICATION
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I conducted or supervised this test by observation of (a) meter readings or (b) the top and bottom gauges of each tank into which production was run during the test. I further certify that the potential test data shown above is true, correct, and complete, to the best of my knowledge.

G.J. Castleberry — Signature: Well Tester
Sypco Inc. — Name of Company
RRC Representative

OPERATOR'S CERTIFICATION
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

W. L. Schopf — Typed or printed name of operator's representative
Dist. RRC Coordinator — Title of Person
(512) 993-3510 — Telephone: Area Code Number
12 / 31 / 86 — Date: mo. day year
337
W.L. Schopf — Signature

CTION II — DATA ON WELL COMPLETION AND LOG (Not Required on Retest)

Type of Completion: New Well [ ] Deepening [ ] Plug Back [ ] Other [XX]

25. Permit to Drill, Plug Back or Deepen — DATE — PERMIT NO.
Rule 37 Exception — CASE NO.
Water Injection Permit — PERMIT NO.
Salt Water Disposal Permit — PERMIT NO.
Other — PERMIT NO.

Notice of Intention to Drill this well was filed in Name of: Texaco Inc.

Number of producing wells on this lease in this field (reservoir) including this well: 5

28. Total number of acres in this lease: 267

Date Plug Back, Deepening, WorkOver or Drilling Operations: Commenced 12-4-86; Completed 12-6-86

30. Distance to nearest well, Same Lease & Reservoir: 500'

Location of well, relative to nearest lease boundaries of lease on which this well is located: 1265 Feet From East Line and 735 Feet from North Line of the H.J. Kuhn Tr. 1 Lease

Elevation (DF, RKB, RT, GR, ETC.): 11.6

33. Was directional survey made other than inclination (Form W—12)? [ ] Yes [XX] No

Top of Pay	35. Total Depth	36. P. B. Depth	37. Surface Casing Determined by:
5883'	5950'	5912'	Field Rules [X]; Recommendation of T.D.W.R. [ ] Dt. of Letter; Railroad Commission (Special) [ ] Dt. of Letter

Is well multiple completion? NO

39. If multiple completion, list all reservoir names (completions in this well) and Oil Lease or Gas ID No.

FIELD & RESERVOIR	GAS ID or OIL LEASE #	Oil—O Gas—G	WELL #

40. Intervals Drilled by: Rotary Tools X; Cable Tools

Name of Drilling Contractor: Cormier Well Ser.

42. Is Cementing Affidavit Attached? [ ] Yes [XX] No

CASING RECORD (Report All Strings Set in Well)

CASING SIZE	WT #/FT.	DEPTH SET	MULTISTAGE TOOL DEPTH	TYPE & AMOUNT CEMENT (sacks)	HOLE SIZE	TOP OF CEMENT	SLURRY VOL. cu. ft.
10-3/4"	32.75	1016'		500/ H 8%gel	15"	Surface	1.73
5-1/2"	14.00	5881"		450/ class H	9-7/8"	2295	1.22

LINER RECORD

Size	TOP	Bottom	Sacks Cement	Screen
3-1/2"	5883'	5927'		

TUBING RECORD

Size	Depth Set	Packer Set
2-3/8"		3400'

46. Producing Interval (this completion) Indicate depth of perforation or open hole

From	To
5883'	5909'

ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

Depth Interval	Amount and Kind of Material Used

FORMATION RECORD (LIST DEPTHS OF PRINCIPAL GEOLOGICAL MARKERS AND FORMATION TOPS)

Formations	Depth	Formations	Depth
Marg.	5881'		

MARKS: Production rate based on waterflood response allowable fro Port Neches Field.

To: Sour Lake

Type or print only

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division

Form W-2
Rev. 4/1/83
483-046

API No. 42-

7. RRC District No. 3

Oil Well Potential Test, Completion or Recompletion Report, and Log

8. RRC Lease No. 03411

1. FIELD NAME (as per RRC Records or Wildcat) Port Neches	2. LEASE NAME H.J. Kuhn, Tract 1	9. Well No. 38
3. OPERATOR'S NAME (Exactly as shown on Form P-5, Organization Report) Texaco Inc.	RRC Operator No. 844110	10. County of well site Orange
4. ADDRESS 1834 N. Main, Liberty, Texas, 77575		11. Purpose of filing: Initial Potential [ ] Retest [x] Reclass [ ] Well record only (explain in Remarks) [ ]
5. If Operator has changed within last 60 days, name former operator		
6a. Location (Section, Block, and Survey) Selestan Sclavon A-431	6b. Distance and direction to nearest town in this county. 2½ miles NE Port Neches, Texas	
12. If workover or reclass, give former field (with reservoir) & gas ID or oil lease no. FIELD & RESERVOIR	GAS ID or OIL LEASE # / Oil - O Gas - G / WELL NO.	
13. Type of electric or other log run	14. Completion or recompletion date 12/5/84	

SECTION I: POTENTIAL TEST DATA IMPORTANT: Test should be for 24 hours unless otherwise specified in field rules.

15. Date of test 12/9/84	16. No. of hours tested 24	17. Production method (Flowing, Gas Lift, Jetting, Pumping—Size & Type of pump) Flowing			18. Choke size
19. Production during Test Period ▶	Oil - BBLS 56	Gas — MCF 175	Water - BBLS 104	Gas - Oil Ratio 3125	Flowing Tubing Pressure 890 PSI
20. Calculated 24-Hour Rate ▶	Oil - BBLS	Gas — MCF	Water — BBLS	Oil Gravity—API—60° 34.2	Casing Pressure 100 PSI
21. Was swab used during this test? Yes [ ] No [X]	22. Oil produced prior to test (New & Reworked wells) 139bbls.				23. Injection Gas—Oil Ratio

REMARKS:

INSTRUCTIONS: File an original and one copy of the completed Form W-2 in the appropriate RRC District Office within 30 days after completing a well and within 10 days after a potential test. If an operator does not properly report the results of a potential test within the 10-day period, the effective date of the allowable assigned to the well will not extend back more than 10 days before the W-2 was received in the District Office. (Statewide Rules 16 and 51) To report a completion or recompletion, fill in both sides of this form. To report a retest, fill in only the front side.

WELL TESTER'S CERTIFICATION
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I conducted or supervised this test by observation of (a) meter readings or (b) the top and bottom gauges of each tank into which production was run during the test. I further certify that the potential test data shown above is true, correct, and complete, to the best of my knowledge.

Garth J. Castleberry — Signature: Well Tester
Texaco U.S.A. — Name of Company
RRC Representative

OPERATOR'S CERTIFICATION
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

CARRIE SHEFFIELD — Typed or printed name of operator's representative
R. R. C. CLERK — Title of Person
409 / 336-3621 — Telephone Area Code Number
12 / 17 / 84 — Date: mo. day year
Carrie Sheffield — Signature

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SECTION II — DATA ON WELL COMPLETION AND LOG (Not Required on Retest)

24. Type of Completion: New Well [ ] Deepening [ ] Plug Back [ ] Other [X]

25. Permit to Drill, Plug Back or Deepen — DATE — PERMIT NO.
Rule 37 Exception — CASE NO.
Water Injection Permit — PERMIT NO.
Salt Water Disposal Permit — PERMIT NO.
Other — PERMIT NO.

26. Notice of Intention to Drill this well was filed in Name of

27. Number of producing wells on this lease in this field (reservoir) including this well

28. Total number of acres in this lease

29. Date Plug Back, Deepening, WorkOver or Drilling Operations: Commenced 11/6/84 Completed 12/5/84

30. Distance to nearest well, Same Lease & Reservoir

31. Location of well relative to nearest lease boundaries of lease on which this well is located: 1381 Feet From West Line and 1785 Feet from South Line of the H.J. Kuhn, Tract 1 Lease

32. Elevation (DF, RKB, RT, GR, ETC.)

33. Was directional survey made other than inclination (Form W—12)? [ ] Yes [ ] No

34. Top of Pay

35. Total Depth 6075'

36. P. B. Depth 5789'

37. Surface Casing Determined by: Field Rules [ ] Recommendation of T.D.W.R. [ ] Railroad Commission (Special) [ ] Dt. of Letter Dt. of Letter

38. Is well multiple completion?

39. If multiple completion, list all reservoir names (completions in this well) and Oil Lease or Gas ID No.

FIELD & RESERVOIR	GAS ID or OIL LEASE #	Oil—O Gas—G	WELL #

40. Intervals Drilled by: Rotary Tools Cable Tools

41. Name of Drilling Contractor

42. Is Cementing Affidavit Attached? [ ] Yes [ ] No

43. CASING RECORD (Report All Strings Set in Well)

CASING SIZE	WT #/FT.	DEPTH SET	MULTISTAGE TOOL DEPTH	TYPE & AMOUNT CEMENT (sacks)	HOLE SIZE	TOP OF CEMENT	SLURRY VOL. cu. ft.

44. LINER RECORD

Size	TOP	Bottom	Sacks Cement	Screen

45. TUBING RECORD

Size	Depth Set	Packer Set
2-3/8"		5615'

46. Producing Interval (this completion) Indicate depth of perforation or open hole

From	To
5752'	5784'

47. ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

Depth Interval	Amount and Kind of Material Used
3232'-3429'	150 sks. LWL, 50 sks. H neat
5752'-5784'	250 gals. 15% HCl
	500 gals. 12/3 mud acid
	250 gals. 15% HCl

48. FORMATION RECORD (LIST DEPTHS OF PRINCIPAL GEOLOGICAL MARKERS AND FORMATION TOPS)

Formations	Depth	Formations	Depth

REMARKS Hole in Csg. 3390-96, Sq. 195 sks.-5 left in Csg., Acidize 5752-84, Washed & Cir. Clean to 5789'.

Received from C.C.

Type or print only

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division

Form W-2
Rev. 4/1/83
483-046

API No. 42-

7. RRC District No. 3

Oil Well Potential Test, Completion or Recompletion Report, and Log

8. RRC Lease No. 03411

1. FIELD NAME (as per RRC Records or Wildcat): Port Neches
2. LEASE NAME: H.J. Kuhn, Tract 1
9. Well No.: 53
3. OPERATOR'S NAME (Exactly as shown on Form P-5, Organization Report): Texaco Inc.
RRC Operator No.: 844110
10. County of well site: Orange
4. ADDRESS: P.O. Box 8992, Corpus Christi, Texas, 78412
5. If Operator has changed within last 60 days, name former operator:
6a. Location (Section, Block, and Survey): Seleston Sclavon A-431
6b. Distance and direction to nearest town in this county:
12. If workover or reclass, give former field (with reservoir) & gas ID or oil lease no.
FIELD & RESERVOIR | GAS ID or OIL LEASE # | Oil - O Gas - G | WELL NO.
13. Type of electric or other log run: PDC, Dual Induction/Gamma Ray
14. Completion or recompletion date: 1/4/85

11. Purpose of filing
- Initial Potential [ ]
- Retest [X]
- Reclass [ ]
- Well record only (explain in Remarks) [ ]

SECTION I: POTENTIAL TEST DATA IMPORTANT: Test should be for 24 hours unless otherwise specified in field rules.

15. Date of test	16. No. of hours tested	17. Production method (Flowing, Gas Lift, Jetting, Pumping—Size & Type of pump)	18. Choke size
1/13/86	24	Gas Lift	

19. Production during Test Period ▶	Oil - BBLS	Gas — MCF	Water - BBLS	Gas - Oil Ratio	Flowing Tubing Pressure
	158	22	637	139	PSI
20. Calculated 24-Hour Rate ▶	Oil - BBLS	Gas — MCF	Water — BBLS	Oil Gravity—API—60°	Casing Pressure
				36.7°	PSI

21. Was swab used during this test? Yes [ ] No [X]
22. Oil produced prior to test (New & Reworked wells): 275 Bbls.
23. Injection Gas—Oil Ratio: 1108

REMARKS:

INSTRUCTIONS: File an original and one copy of the completed Form W-2 in the appropriate RRC District Office within 30 days after completing a well and within 10 days after a potential test. If an operator does not properly report the results of a potential test within the 10-day period, the effective date of the allowable assigned to the well will not extend back more than 10 days before the W-2 was received in the District Office. (Statewide Rules 16 and 51) To report a completion or recompletion, fill in both sides of this form. To report a retest, fill in only the front side.

WELL TESTER'S CERTIFICATION
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I conducted or supervised this test by observation of (a) meter readings or (b) the top and bottom gauges of each tank into which production was run during the test. I further certify that the potential test data shown above is true, correct, and complete, to the best of my knowledge.

G.J. Castleberry — Signature: Well Tester
Texaco Inc — Name of Company
RRC Representative

OPERATOR'S CERTIFICATION
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

R.J. Rowalt — Typed or printed name of operator's representative
District Manager — Title of Person
512-993-3510 — Telephone: Area Code Number
1 / 17 / 86 — Date: mo. day year
R.J. Rowalt /pm — Signature

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ECTION II — DATA ON WELL COMPLETION AND LOG (Not Required on Retest)

1. Type of Completion: New Well [ ] Deepening [ ] Plug Back [X] Other [ ]

25. Permit to Drill, Plug Back or Deepen — DATE — PERMIT NO.
Rule 37 Exception — CASE NO.
Water Injection Permit — PERMIT NO.
Salt Water Disposal Permit — PERMIT NO.
Other — PERMIT NO.

3. Notice of Intention to Drill this well was filed in Name of

7. Number of producing wells on this lease in this field (reservoir) including this well: 5

28. Total number of acres in this lease: 267

9. Date Plug Back, Deepening, WorkOver or Drilling Operations: Commenced 12/4/85 Completed 1/4/86

30. Distance to nearest well, Same Lease & Reservoir

1. Location of well, relative to nearest lease boundaries of lease on which this well is located: 1297 Feet From North Line and 870 Feet from West Line of the H.J. Kuhn, Tract 1 Lease

2. Elevation (DF, RKB, RT, GR, ETC.)

33. Was directional survey made other than inclination (Form W—12)? [ ] Yes [ ] No

4. Top of Pay | 35. Total Depth 5940' | 36. P. B. Depth 5860' | 37. Surface Casing Determined by: Field Rules [ ] Recommendation of T.D.W.R. [ ] Dt. of Letter; Railroad Commission (Special) [ ] Dt. of Letter

3. Is well multiple completion?

39. If multiple completion, list all reservoir names (completions in this well) and Oil Lease or Gas ID No.

FIELD & RESERVOIR	GAS ID or OIL LEASE #	Oil—O Gas—G	WELL #

40. Intervals Drilled by: Rotary Tools | Cable Tools

1. Name of Drilling Contractor

42. Is Cementing Affidavit Attached? [ ] Yes [ ] No

3. CASING RECORD (Report All Strings Set in Well)

CASING SIZE	WT #/FT.	DEPTH SET	MULTISTAGE TOOL DEPTH	TYPE & AMOUNT CEMENT (sacks)	HOLE SIZE	TOP OF CEMENT	SLURRY VOL. cu. ft.

4. LINER RECORD

Size	TOP	Bottom	Sacks Cement	Screen

5. TUBING RECORD

Size	Depth Set	Packer Set
2-3/8"		5753

46. Producing Interval (this completion) Indicate depth of perforation or open hole

From	5788'	To	5804'
From		To	
From		To	
From		To	

7. ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

Depth Interval	Amount and Kind of Material Used
4716'-4726'	100 sks. LWL & 100 sks. class "H" neat

8. FORMATION RECORD (LIST DEPTHS OF PRINCIPAL GEOLOGICAL MARKERS AND FORMATION TOPS)

Formations	Depth	Formations	Depth

EMARKS

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division

Type or print only

Form W-2
Rev. 4/1/83
483-046

Received 5-1- 4/25/86

API No. 42-

7. RRC District No. 3

Oil Well Potential Test, Completion or Recompletion Report, and Log

8. RRC Lease No. 03412

1. FIELD NAME (as per RRC Records or Wildcat): Port Neches
2. LEASE NAME: H. J. Kuhn Tract 2
9. Well No. 6
3. OPERATOR'S NAME (Exactly as shown on Form P-5, Organization Report): Texaco Inc.
RRC Operator No.
10. County of well site: Orange
4. ADDRESS: P.O. Box 8992, Corpus Christi, Texas, 78412
5. If Operator has changed within last 60 days, name former operator
11. Purpose of filing
Initial Potential ☐
Retest ☒
Reclass ☐
Well record only (explain in Remarks) ☐
6a. Location (Section, Block, and Survey): W. R. Hill A-442
6b. Distance and direction to nearest town in this county: 5 miles E, Bridge City, Texas
12. If workover or reclass, give former field (with reservoir) & gas ID or oil lease no.
FIELD & RESERVOIR | GAS ID or OIL LEASE # | Oil - O Gas - G | WELL NO.
13. Type of electric or other log run
14. Completion or recompletion date 4/2/86

SECTION I: POTENTIAL TEST DATA IMPORTANT: Test should be for 24 hours unless otherwise specified in field rules.

15. Date of test: 4-8-86
16. No. of hours tested: 24
17. Production method (Flowing, Gas Lift, Jetting, Pumping-Size & Type of pump): 1½"
18. Choke size

	Oil - BBLS	Gas — MCF	Water - BBLS	Gas - Oil Ratio	Flowing Tubing Pressure
19. Production during Test Period ▶	16	9	65	563	PSI
20. Calculated 24-Hour Rate ▶	Oil - BBLS	Gas — MCF	Water — BBLS	Oil Gravity—API—60° 35.4	Casing Pressure PSI

21. Was swab used during this test? Yes ☐ No ☒
22. Oil produced prior to test (New & Reworked wells)
23. Injection Gas—Oil Ratio

REMARKS:

INSTRUCTIONS: File an original and one copy of the completed Form W-2 in the appropriate RRC District Office within 30 days after completing a well and within 10 days after a potential test. If an operator does not properly report the results of a potential test within the 10-day period, the effective date of the allowable assigned to the well will not extend back more than 10 days before the W-2 was received in the District Office. (Statewide Rules 16 and 51) To report a completion or recompletion, fill in both sides of this form. To report a retest, fill in only the front side.

WELL TESTER'S CERTIFICATION
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I conducted or supervised this test by observation of (a) meter readings or (b) the top and bottom gauges of each tank into which production was run during the test. I further certify that the potential test data shown above is true, correct, and complete, to the best of my knowledge.

G. J. Castleberry — Signature: Well Tester
Texaco Inc. — Name of Company
RRC Representative

OPERATOR'S CERTIFICATION
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

W. L. Schopf — Typed or printed name of operator's representative
Dist. RRC Coordinator — Title of Person
(512) 993-3510 — Telephone: Area Code Number
4/22/86 — Date: mo. day year
W. L. Schopf — Signature

CTION II — DATA ON WELL COMPLETION AND LOG (Not Required on Retest)

Type of Completion: New Well ☐ Deepening ☐ Plug Back ☐ Other ☒

Notice of Intention to Drill this well was filed in Name of

25. Permit to Drill, Plug Back or Deepen	DATE	PERMIT NO.
Rule 37 Exception		CASE NO.
Water Injection Permit		PERMIT NO.
Salt Water Disposal Permit		PERMIT NO.
Other		PERMIT NO.

Number of producing wells on this lease in this field (reservoir) including this well

28. Total number of acres in this lease

Date Plug Back, Deepening, WorkOver or Drilling Operations: Commenced 3/19/86 Completed 4/2/86

30. Distance to nearest well, Same Lease & Reservoir

Location of well, relative to nearest lease boundaries of lease on which this well is located: 150 Feet From South Line and 150 Feet from West Line of the H. J. Kuhn Tr. 2 Lease

Elevation (DF, RKB, RT, GR, ETC.)

33. Was directional survey made other than inclination (Form W—12)? ☐ Yes ☐ No

Top of Pay	35. Total Depth	36. P. B. Depth	37. Surface Casing Determined by:	Field Rules ☐	Recommendation of T.D.W.R. ☐	Dt. of Letter
	5939'	5892'			Railroad Commission (Special) ☐	Dt. of Letter

Is well multiple completion?

39. If multiple completion, list all reservoir names (completions in this well) and Oil Lease or Gas ID No.

FIELD & RESERVOIR	GAS ID or OIL LEASE #	Oil—O Gas—G	WELL #

40. Intervals Drilled by: Rotary Tools | Cable Tools

Name of Drilling Contractor

42. Is Cementing Affidavit Attached? ☐ Yes ☐ No

CASING RECORD (Report All Strings Set in Well)

CASING SIZE	WT #/FT.	DEPTH SET	MULTISTAGE TOOL DEPTH	TYPE & AMOUNT CEMENT (sacks)	HOLE SIZE	TOP OF CEMENT	SLURRY VOL. cu. ft.

LINER RECORD

Size	TOP	Bottom	Sacks Cement	Screen

TUBING RECORD

Size	Depth Set	Packer Set
2 3/8"	5671	

46. Producing Interval (this completion) Indicate depth of perforation or open hole

From	To
5882'	5890'

ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

Depth Interval	Amount and Kind of Material Used

FORMATION RECORD (LIST DEPTHS OF PRINCIPAL GEOLOGICAL MARKERS AND FORMATION TOPS)

Formations	Depth	Formations	Depth

MARKS