PRELIMINARY WORK ON AN INTEGRATED STUDY OF THE GRAYBURG AND SAN ANDRES RESERVOIRS, FOSTER AND SOUTH COWDEN FIELDS, ECTOR COUNTY, TEXAS

W. Hoxie Smith
Dawson Geophysical Company
Midland, Texas

James J. Reeves+, PhD
The University of Texas of the Permian Basin
Odessa, Texas

Robert C. Trentham, DGS
Muskoka Consultants
Midland, Texas

David A. Rowland*, PhD, P.E.
RowTech
Midland, Texas

+ Affiliated with Spectrum Services, Inc. Odessa, Texas
* Member SPE

Abstract

A cooperative study of the Grayburg/San Andres reservoir is being conducted in response to the United States Department of Energy's Class II Oil Program. The purpose of this study is to preserve access to existing wellbores by identifying additional reserves. Production problems associated with shallow shelf carbonate reservoirs are being evaluated by a technical team integrating subsurface geological and engineering data with 3-D seismic data. Engineering analysis, subsurface control from wireline logs, and 3-D seismic data will be integrated using a network of state-of-the-art software on a high performance computer workstation.

It is expected that this study will demonstrate a methodology for reservoir characterization and subsequent development of the Grayburg and San Andres reservoirs that is feasible for even small independent operators. The integrated multi-disciplinary approach of reservoir evaluation is relevant to many shallow shelf carbonate reservoirs throughout the United States.

This paper reports on some of the work performed to date which consists mainly of collecting and appraising large volumes of data, principally well logs, well completion records, and laboratory results of rock and fluid property measurements. Much early well data is missing; this being a field discovered nearly 60 years ago at a time when such extensive reservoir evaluations were not contemplated. This factor is inherent in many fields in the surrounding area that have been successfully waterflooded. With the aid of modern technology, combined with sophisticated geological and engineering analyses, the probability of determining the economic feasibility of waterflooding this acreage should be enhanced.

Introduction

A cooperative study of the Grayburg/San Andres reservoir is being conducted in response to the United States Department of Energy's Class II Oil Program (1). The purpose of this study is to preserve access to existing wellbores by identifying additional reserves. Production problems associated with shallow shelf carbonate reservoirs are being evaluated by a technical team integrating subsurface geological and engineering data with 3-D seismic data. Engineering analysis, subsurface control from wireline logs, and 3-D seismic data will be integrated using a network of state-of-the-art software on a high performance computer workstation.

The area contained in this study encompasses approximately 1000 acres with more than 60 wells drilled. An index map showing the location of the study area in the southern portion of the Foster Field is shown in Fig. 1. A few wells have been converted to waste-water disposal wells; no formal pattern was incorporated so a true waterflood design has not as yet been initiated. Two main producing reservoirs are included in the study: the Grayburg and San Andres Formations. If the results indicate a waterflood is technically feasible, a proposal for an optimal design for injection and producing wells will be included. An economical analysis will be made to compare the value of increased reserves with possible new infill wells, recompletions, and deepening of some existing wells.

Development History

The Foster and South Cowden Fields, located in Ector County, Texas, were discovered in 1932. Production was encountered in the Upper Grayburg dolomite at a depth of around 3,800 feet. Development was slow due to low oil prices. By 1941, development on 40-acre spacing was generally completed throughout. Early completion practices of wells were "open hole" and shooting with nitroglycerin. Initial potentials were quite high, reaching as much as 1,500 STB/D. Because of the tightness of the dolomite, producing rates declined rapidly.

During the mid-fifties, most wells were restimulated by using fracturing techniques that generally produced good results. In 1965, reinjection of lease water into the producing zones was begun. Injection patterns were haphazard with no particular waterflood design being considered. The injection zones responded favorably when surrounding wells showed substantial increases in oil production.

During the early seventies, infill drilling occurred with the new wells penetrating the upper San Andres accumulations. This new drilling resulted in a surge of production that rapidly declined as before. Then, in the early eighties, several offset leases were converted to full-scale, well engineered waterflood projects. These efforts to stimulate production have all reported significant increases in oil recoveries. Accordingly, there seems little doubt that similar responses can be expected in the subject area.

Geology

Grayburg

The Grayburg was deposited as a carbonate ramp on the eastern margin of the Central Basin Platform. The carbonate ramp slowly deepened across the study area from west to east into the Midland Basin. Lindsay, et al (2) conclude that the Grayburg was deposited as numerous packages of sediments (parasequences) ranging in thickness of from 5 to 30' that act as flow units in the reservoir. These shallowing-upward units are composed of siliciclastic bases and carbonate tops. The siliciclastics range from dolomitic to highly dolomitic and were deposited only as part of some parasequences. The carbonate portion of each unit has been completely dolomitized.

On the deeper portion of the ramp (most eastern part) the Grayburg dolostones are composed of thicker bedded, higher energy grainstones and packstones. Landward, the dolostones are composed of thinner bedded, muddier packstones and wackestones. In between, the thicker and thinner units interfinger. The individual flow units are, therefore, thicker down dip and thinner and more numerous up dip. The siliciclastic basal beds are thicker and more numerous in the upper third of the Grayburg. The fine grained siliciclastics were originally transported onto the shelves during sea level lowstands. Once the sea level rose and flooded the shelf, the sands were reworked along with the dolomitic rubble and any soil which formed during the lowstand. These basal units have sharp bases and gradational tops and although they do not appear to have enhanced the reservoir quality, they created a characteristic high gamma ray signature. This signature can be correlated across the study area and is used as a marker by stratigraphers (3) to subdivide the Grayburg into eight separate units. Most of these units represent either flow units or "bundles" of flow units.

Porosity distribution within the Grayburg is controlled by both depositional facies and diagenesis. The thicker bedded grain-rich facies, most often seen in the down dip portion of each sequence, have the best porosity; whereas, the thinner bedded mud-rich facies have the poorest. Subaerial exposure of the individual units, though short lived, created additional secondary dissolution porosity. Deep burial diagenesis enhanced both porosity and permeability.

San Andres

The San Andres was deposited in a similar environment as the Grayburg. There is, however, a lack of siliciclastics in the San Andres and the distinctive basal beds are absent. Consequently, the "shaley" gamma ray signature is also absent. Although the San Andres and Grayburg reservoirs have a similar depositional history they have very dissimilar diagenetic histories. This resulted in the subsequent hydrocarbon accumulations being quite different. At the end of San Andres time there was a major (+/- 250 feet), long term sea level drop which subaerially exposed the porous intervals and caused extensive dissolution, reprecipitation, and infilling with debris (karstification). The upper San Andres in the study area was above the water table and undergoing major dissolution and collapse. The blocky character of the porous zones in the upper San Andres is a result of this process. This resulted in the development of an extensive network of reservoirs having highly variable permeabilities in both the vertical and horizontal directions. Permian Basin carbonate reservoirs that have undergone extensive karstification are referred to as "Big Tanks" because of the channeled network, however a well can be drilled that will not exhibit karst features because of the variable nature of karstification.

A type-log showing both the Grayburg and upper portion of the San Andres Formations is given in Fig. 2.

Geophysics

In recent years a major breakthrough has occurred in exploration geophysics with the development of 3-D seismic technology. The reason is the truly remarkable difference in resolution between 2-D and 3-D seismic data. A 3-D seismic data volume samples the subsurface at a much greater density than a normal 2-D seismic grid. This greater subsurface sampling enables 3-D seismic methods to easily resolve the overall structural and stratigraphic framework in the reservoir including major and minor faults that may act as barriers to fluid flow.

The most important advantage of 3-D seismic techniques is that reflections can be migrated to their true position in the subsurface. In principle, seismic migration is a three dimensional problem that can only be handled properly in a 3-D data volume. For this reason seismic attributes extracted from 3-D seismic data are much more sensitive to petrophysical parameters in the reservoir that effect reservoir flow geometry. For example, an accurate measure of seismic amplitudes, related to changes in acoustic impedance, may allow estimation of reservoir parameters such as porosity and lithology.

In this study a high resolution 3-D seismic survey was shot over 3.25 square miles of the South Cowden and Foster oil fields, Ector County, Texas as shown in Fig.3. Our objective is the Permian Grayburg and San Andres Formations at depths of about 3800 to 5000 feet. To avoid cultural obstructions (including a number of houses, buildings, and wells) the entire 3-D seismic survey was initially designed using an aerial photograph covering the study area. The east-west receiver lines were spaced on about 660 foot centers whereas the north-south source lines were spaced on approximately 1320 foot centers. Source and receiver group intervals were each 220 feet. The survey was shot using a fixed spread consisting of 679 receiver groups and 438 source locations. During the acquisition of the 3-D seismic survey any deviated location for a source or receiver group greater than 10 feet from the original station was re-surveyed. A correct reservoir characterization requires that each well location in the project area be accurately surveyed.

The 3-D seismic data is being processed at Dawson Geophysical Company using SSL Phoenix Vector 3-D seismic data processing software. Particular emphasis is being placed on designing a deconvolution operator to adjust the phase and amplitude of the data to tie synthetic seismograms computed from wireline logs in the study area.

Source and receiver lines were positioned to allow a bin fractionization process to give an option of two different bin sizes (110 feet x 110 feet or 55 feet x 55 feet) to generate the seismic image. Imaging done with the smaller bin size has maximum fold of about 6 or 7 whereas with the larger bin size the maximum fold is about 25. The advantage of the smaller bin is that it increases the subsurface sampling of the 3D seismic image by a factor of 4. For reservoir characterization studies this can be very desirable provided the data has adequate signal to noise ratio.

An integrated interpretation and analysis of geological, geophysical, and engineering data will be done using a Sun SPARCstation 5 high performance computer workstation provided by Spectrum Services. The following software packages are available for the project:

> Scientific Software-Intercomp WorkBench - log analysis, reservoir description and reservoir simulation
>
> Terrasciences TERRASTATION - geologic cross section building and well log analysis
>
> Schlumberger GeoQuest IES - 3D seismic interpretation
>
> Advanced Geophysical Prospector - seismic attribute mapping
>
> GX Technology GX II/3DAIMS - seismic modeling
>
> Landmark Graphics ZMAP - geologic mapping

3-D seismic interpretation is done primarily using IES and Prospector software. The use of automatic picking routines allows quick mapping of seismic attributes and display using high resolution color maps. The interactive seismic workstation is a very powerful tool used in petroleum exploration today.

Well control is tied into the 3-D data volume by computing synthetic seismograms from wireline sonic and density logs. For wells where sonic and density logs are not available synthetic seismograms are synthesized from other wireline logs provided suitable transfer functions can be developed. Most of the logs in the Grayburg/San Andres interval in the study are digitized. The sequence stratigraphic interpretation of the well logs in the Grayburg/San Andres reservoir are integrated with the 3-D seismic data volume by correlating sets of parasequences interpreted in the well logs to seismic attributes. To design the reservoir simulation model, the spatial distribution of reservoir properties, measured in boreholes, are extrapolated through the 3-D data volume using the integrated sequence stratigraphic interpretation as a correlation tool. Quantitative information on reservoir properties such as fluid content and porosity may be extracted from the data from seismic amplitude or other attributes.

The general stratigraphy through the study area can be seen in Fig. 4 in an east-west 2-D seismic section. Subsurface control is tied to the seismic line through a synthetic seismogram computed from a sonic log in a well located about 600 feet from the line. Reservoir flow compartments are influenced by the geometry of the depositional surfaces or clinoforms in the Grayburg reservoir. The lateral continuity of reflections in the Grayburg is an indication of the high degree of lateral continuity of reservoir flow compartments found in these strata, whereas the lack of reflection continuity in the San Andres reservoir is caused by the widespread dissolution or karsting found in this formation. The thin parasequences forming the Grayburg as opposed to the more massive nature of the San Andres are also interpreted in the type log for the study area (Fig. 2). High resolution/high frequency 3-D seismic data will allow a much more precise definition of the flow compartments in the Grayburg and San Andres reservoirs.

Producibility and Reservoir Characterization

The Grayburg and San Andres Formations are characterized by a high degree of stratigraphic heterogeneity and lenticularity. The flow compartments are randomly oriented and often interspersed with deposits of anhydrite which serve as flow barriers. These features tend to hinder sweep efficiency of waterfloods that lower recoveries. Additionally, high permeability stringers, or channels, further reduce waterflood recoveries. With the aid of a 3-D developed reservoir model, the various heterogeneities and barriers may be delineated in order that an optimal design of the flood pattern may be evaluated.

Reservior Engineering

Reservoir Rock Properties

For purposes of obtaining representative average values of porosity and permeability for both the Grayburg and San Andres Formations, a 3% porosity cutoff has been selected. In addition, only those samples measuring a permeability of 0.1 md or greater are counted as pay. The 0.1 md permeability cutoff is the industry standard adapted for Permian Basin dolomites. Opposing views on correct porosity cutoff values are reported in the literature giving rise to some controversy as to which value is more appropriate. George and Stiles (4) conducted a study on the effect of porosity cutoff values on Original Oil in Place in three Permian Basin dolomite fields. They reported in one field that 56% of the samples with 3% porosity would qualify as being pay. Thus, if a porosity cutoff value greater than 3% was selected, a significant volume of oil could be excluded in the determination of original oil in place.

The fact that wells in the study area exhibit low producing rates for extended periods of time is indicative that low porosity hence, low permeability flow compartments are contributing to primary recovery. For this reason, the 3% porosity cutoff is believed to be justifiable for this study area.

Porosity and permeability: Routine core analyses are available from three wells cored in the study area. First, the Witcher No. 6, was drilled and completed in July 1970. Coring commenced at a depth of 3,850 feet using a 4" diamond core bit. A total of five cores were taken from the Grayburg with coring continuing to a depth of 4,025 feet. Recovery was 100% giving a total of 175 feet of core. A sixth core was cut in the San Andres Formation from a depth of 4,260 feet to 4,314 feet. Water base mud was used in the coring operation.

Ninety two whole-core samples from the Grayburg Formation were used to measure routine core properties in the laboratory , and another 39 samples cut from core No. 6. Measured values include absolute permeability (both maximum and 90 deg.), porosity, and residual oil and water saturations. A large portion of the samples tested showed permeabilities of less than 0.1 md. Only 15 samples of the 92 Grayburg cores tested survived the dual cutoff requisite permeability equal to or greater than 0.1 md, and porosity equal to or greater than 3.0%. On the other hand, 26 samples taken from the San Andres core were accepted as potential pay. However, these samples indicated very low oil saturation (averaging less than 10%) and thereby probably not contributing to the production.

The Foster-Pegues No. 3-X well was drilled in August 1961 with coring beginning at a depth of 3,850 feet and continuing to 4,086 feet. (Grayburg Formation). A total of 111 samples cut from these cores were used to measure porosity and permeability, of which only 37 qualified as pay. However, an additional 15 samples were used in measuring water-oil relative permeability and flood-pot tests. Thus, with these results combined with those measured from the Witcher well gives a total of 52 values of porosity and permeability available for conducting a statistical analysis on the Grayburg Formation.

The Brock No. 10 well was drilled and cored in May 1979. Again the drilling fluid was saltwater based and full diameter cores were cut. The cored interval was from 4,290 feet to 4,350 feet (San Andres Formation) with 100 percent recovery. Fifty five samples were tested for porosity and permeability with forty nine samples surviving the dual cutoff tests. An additional 15 samples were used to measure special core properties (water-oil relative permeability and flood-pot tests). Thus, when combining these samples with the Witcher well, a total of 90 porosity and permeability values were available for statistical analyses on the San Andres Formation.

Statistical analyses were conducted on these data for both the Grayburg (52 values) and San Andres (90 values) Formations. These results are summarized in Table 1 and show good agreement with results reported for waterflood studies from adjacent leases. These reports are as follows: Amoco's South Foster Unit (5) and UNOCAL's Moss Unit (6), both being flooded in the Grayburg Formation, and Fina's Emmons Unit (7) undergoing a waterflood in the San Andres, located about four miles south of the study area.

The calculated weighted average porosity for the Grayburg and San Andres Formations are 6.39 and 7.99 percent, respectively. Similarly, the geometric average permeability for the two formations are calculated to be 1.06 and 0.58 md, respectively. It is noteworthy that the San Andres Formation shows a higher average porosity than the Grayburg Formation. Yet, the permeability contrasts are reversed with the San Andres being tighter than the Grayburg. This is not an uncommon trait shown by these two formations as the San Andres is known to contain sandy and silty characteristics which account for these differences in physical properties.

Figures 5 and 6 show, respectively, porosity and permeability histograms for the Grayburg Formation. Figure 7 is a semilog plot of permeability versus porosity. A fairly good correlation is indicated from this plot. Likewise, Figs. 8, 9, and 10 are plots of the same parameters, respectively, for the San Andres Formation. Again, a reasonably good correlation between permeability and porosity is depicted in Fig. 10. These permeability correlations will be used to establish representative values to be used in each grid block of the reservoir simulation model. The equations for permeability for the Grayburg and San Andres Formations are as follows:

Grayburg:

$$\text{Log } k = -0.769 + 0.129 * \text{Phi} \quad (1)$$

San Andres:

$$\text{Log } k = -1.049 + 0.107 * \text{Phi} \quad (2)$$

Using the average porosity values for the two formations listed above, the calculated average permeability using equations 1 and 2, respectively, are 1.18 and 0.65 md. Hence, good agreement between these values and the respective geometric means, listed in Table 1, is clearly indicated.

Pore Volume Compressibility: Reports of rock compressibility measurements were not available for core samples obtained in the three wells cored in the study area. Pore volume compressibilities were examined extensively by Fina (7) in their special core analysis program on the Emmons Unit. They reported the average measured hydrostatic pore volume compressibility at 1600 psig to be 6.85/psi*E6. We will accept this value as being representative for both the Grayburg and San Andres Formations for our study area also.

Capillary Pressure: Although several core samples have been used by offset operators to obtain mercury injection capillary pressure data, the transformation of these data to represent the oil-water system in the reservoir is speculative at most. In the final report submitted by the Moss Unit Engineering Subcommittee, it concludes that "the Grayburg dolomite is neutral in wettability or slightly preferentially water wet." Other evidence supporting the low or intermediate wettability characteristics of both the Grayburg and San Andres Formations is contained in routine core analysis measurements on cores obtained with oil base muds. Many of the cores analyzed show very low water saturations an indication that capillary held water could be very low.

Due to the probable low capillary pressure, neither water-oil nor gas-oil capillary pressure data will be included in the data input of the simulation model.

Connate Water Saturation and Residual Oil Saturation: The Sun Oil Company conducted a waterflood feasibility study on the Witcher lease in 1985 (8). From log analyses on resistivity logs from four wells (Well Nos. 5, 6, 8 and 9), it was determined that the average connate water saturation for the lease was 24.6%. Until additional data is available, we will use this value to represent the connate water saturation for both the Grayburg and San Andres Formations in the study area. It is useful to note that UNOCAL reports the average initial water saturation measured on 104 core samples (cored using oil base fluid) is 31.0%. (6)

On 10 flood-pot tests run on the same core string, UNOCAL reports the residual oil saturation to be 24.0%. Amoco, on the other hand, reports the residual oil saturation measured on three "full diameter" Grayburg cores subjected to waterflood tests showed the average residual oil saturation to be 32.3%. (5)

Relative Permeability Data: Several cores in the Foster/South Cowden Field Complex have been used to obtain both gas-oil and water-oil relative permeability data (5, 6, 7). In addition, Arco measured water-oil relative permeabilities on three cores obtained from the San Andres Formation in their Brock No. 10 Well (9). An examination of these various measurements was conducted to ascertain which data set best represented producing zones in our area. Based on this analysis, the following data have been selected to represent relative permeability relationships for the study area. It is recognized, however, that these will be modified somewhat with history matching during model runs. These adjustments become necessary to account for the severe gas channeling usually experienced in these tight, heterogeneous dolomitic formations.

Gas-Oil:

Several cores were used to measure gas-oil relative permeability as reported by Fina (7), both by the steady state method and the dynamic method. A composite plot of all data was made for both gas and oil relative permeabilities. The results indicated a wide variation between the samples tested as well as between the two methods of measurement. As a consequence, it was concluded that a single set of data should be selected to represent this parameter for introduction into the reservoir simulator. Their sample labeled E1-10 was chosen for this purpose. Results of the laboratory derived data along with pertinent core properties are reproduced directly from the Fina report. These data appear herein in Table 2, and presented graphically in Fig. 11.

Water-Oil:

Even more cores were analyzed for water-oil flow characteristics than were reported for the gas-oil relative permeability relationship. For the Grayburg Formation, we have selected three sets of measurements reported by Amoco (5). Their leases border the study area on the north; hence, they should be an adequate representation for use in our model studies. A computer program (RPERM) was used to normalize these data to conform with the irreducible water saturation of 24.6% as reported above. The resulting individual water and oil relative permeability relationships are tabulated in Table 3, and presented graphically in Fig. 12.

For the San Andres Formation, relative permeability measurements conducted on four cores from the Brock No. 10 (9) were used. These cores were analyzed by the unsteady-state method of measurement. Again, a composite of these four curves was constructed for both the water and the oil relative permeabilities. The laboratory derived measurements on the four cores appear to be very erratic and inconclusive. Moreover, the average residual oil saturation calculates to be 56.4% whereas the average initial water saturation calculates to be 23.8%. This indicates a very low movable oil saturation of only 32.6%.

The arithmetic mean values for porosity and permeability of these four cores are 7.7 percent and 1.38 md, respectively. These values compare very well with the statistically derived averages listed in Table 1. The composite water and oil relative permeabilities for the San Andres are given in Table 3, and are displayed graphically in Fig. 13. Normalization to a representative area wide average irreducible water saturation is being deferred until log data has been fully analyzed.

Reservoir Fluid Properties

Initial Reservoir Conditions: Several recordings of initial pressure, temperature, and water-oil contacts have been reported in various engineering studies made on surrounding leases. After careful review of each of these reports, the data from the offset Amoco South Foster Unit (5) appear to be most applicable to the study area when correlated with early well test results. Accordingly, the following parameters are selected for calculation purposes in this investigation:

Initial Reservoir Pressure........................1,740 psia (at 1,000 feet)
Initial Reservoir Temperature.....................95 deg. F
Oil Gravity.......................................35 deg API
Water-Oil Contact.................................-1,535 feet

The Amoco study reports that the water-oil contact actually slants from the northwest portion of the South Cowden field (1,250 feet) to the southeast portion of the South Foster Unit (1,570 feet). No water-oil contacts are exposed in wells drilled in the study area; hence, we will assume the water-oil contact will not be an issue for simulation purposes.

Because the bulk of the production originates from the upper Grayburg Formation, we have selected the approximate mid-level of these producing intervals to serve as the datum. The datum depth selected is 1,100 feet. Using a pressure gradient in the oil column of 0.368 psi/ftcomputed using 35 deg API gravitythe original reservoir pressure at datum is calculated to be 1,777 psia.

Physical Properties of Natural Gas: A separator sample of produced gas was obtained from the Phillips TXL "Z" 4 well (producing from the Grayburg) near the Moss Unit as reported in UNOCAL's report (6). The sample was collected on January 15, 1951 at a separator operating pressure and temperature of 20 psig and 64 deg. F, respectively. The sample was used to measure the compositional analysis of the gas which in turn was used as a basis for determining important physical properties of the liberated gas in the reservoir. These properties include: pseudo-compressibility (Z-factor), gas formation volume factor and gas viscosity as a function of pressure. A computer program (GASPROP) was used to compute these parameters. This program consists of a number of empirical equations similar to those compiled by Horne (10).

The results of computations are presented in Table 4. Figure 14 shows a plot of gas formation volume factor and viscosity vs. pressure. Similarly, Fig. 15 is a plot of Z-factor vs. pressure.

Physical Properties of Crude Oil: Another computer program (OILPROP) was used to calculate various physical properties of the reservoir oil at predetermined pressure decrements between initial pressure and atmospheric conditions. This program also consists of a series of empirical correlations summarized in Horne's (10) textbook. In the absence of actual PVT analyses on oil samples collected in the field, these correlations are considered to be satisfactory. Fina (7) conducted an excellent study on fluid properties of oil samples obtained from San Andres wells in their EMMONS Unit, situated approximately 5 miles south of the study area. Because most of the production obtained from wells in our study area is from the Grayburg Formation, coupled with the remoteness of the Fina study, the decision was made to use empirical methods for generating oil properties for our study.

The results of the computer derived oil properties are listed in Table 5. Graphical representations of oil formation volume factor, solution gas-oil ratio, and oil viscosity are given in Figs. 16, 17, and 18, respectively.

Physical Properties of Formation Water: Several water sample analyses were available for Grayburg/San Andres Formation water for the study area. The earliest sample on record is from the Maurice No. 8 well which was sampled on March 20, 1980 and could be contaminated by injection water. The total dissolved solids measured for this water sample is 58,869 ppm. A correlation program (WATPROP) was used to calculate pertinent water properties at initial reservoir conditions. These properties are summarized as follows:

Viscosity........................0.716 cp
Compressibility..................3.21 E-6/psi
Gas Solubility...................14.6 SCF/STB
Water FVF........................1.001 RB/STB
Water Resistivity................0.0915 ohm-m

Discussion

For this waterflood feasibility study, an "integrated team-work" approach was initiated. The team was composed of one project coordinator and one each geologist, geophysicist, and reservoir engineer. In the integrated approach (as opposed to the assembly line approach where each professional completes his work before the next in line takes over), each professional contributes to the others work simultaneously. In this manner everyone is keenly aware of what the others are doing. This procedure shortens the over all time and effort required to complete the project by reducing unnecessary and/or duplication efforts, streamlines the outflow of data and results, and provides for a more refined and orderly final product.

Following the approval of this project by the Department of Energy on August 2, 1994, the team members met to organize a schedule of events. The first order of business was to conduct the seismic survey. Simultaneously, efforts were made to secure well logs, completion information, and production history on all wells contained in the leases in the study area. Additional well logs were obtained on the first line of wells surrounding the leases for well control at the boundaries. Neighboring offset operators were contacted for both core analysis and fluid property analysis of samples obtained in their Grayburg and San Andres producing wells. To this end, we were very fortunate to obtain a large amount of valuable information that will aid in the understanding of the complex reservoir systems encountered in this area. Hopefully, this cooperative effort will pay dividends to the offset operators by also being rewarded through the results of this study. It is further hoped that other operators, from small independents to majors, may reap benefits by the methods employed in this study.

The advantages of the integrated team-work approach have already been realized in the short time since the study started. This preliminary presentation is to report on the progress of the three main facets of the study: geology, geophysics, and reservoir engineering. These three areas of the study are on-going with Phase I scheduled to be completed by October 1, 1995. Phase II will begin shortly thereafter which involves additional data collecting and model refinement though new drilling and data acquisition. Finally, implementation of a full-scale waterflood of the study area is anticipated.

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Table 1 - Tabulation of Results of Statistical Analyses on Core Data-Foster Field

	LAGUNA	AMOCO	UNOCAL
<u>Grayburg</u>			
Number Samples	52	163	508
Porosity(%)			
Arithmetic Ave.	6.53		
Weighted Ave.	6.39	5.48	
Permeability(md)			
Arithmetic Ave.	4.99		2.1
Weighted Ave.	4.99	3.23	
Geometric Ave.	1.06		0.95
Log k vs Porosity Ave.	1.18		
50%> Value on D-P Plot*	1.25		
Permeability Variation**	.874		.745
<u>San Andres</u>			
Number Samples	90		
Porosity(%)			
Arithmetic Ave.	8 06	8.9	
Weighted Ave.	7 99		
Permeability(md)			
Arithmetic Ave.	1.14		
Weighted Ave.	1.09		
Geometric Ave.	0.58		
Log k vs Porosity Ave.	0.65		
50%> Value on D-P Plot*	0.66		
Permeability Variation**	712		

* A plot of permeability data on log-normal paper

** Dykstra-Parsons permeability variation – an empirical measure of reservoir heterogeneity

Table 2 - Gas-Oil Relative Permeability Test Results

Temperature: 72°F

Fina Oil and Chemical Company	Sample I.D.:	E1-10
Emmons Unit	Depth:	4638.8 feet
Well 142	Permeability to Air:	14.4 md
M3/M34 Facies	Porosity:	16.4 percent
Chaotic Rock Type	Specific Permeability to Oil:	10.6 md

Gas Saturation, percent pore space	Gas-Oil Relative Permeability Ratio	Relative Permeability to Gas,* fraction	Relative Permeability to Oil,* fraction
0.0	0.000	0.0000	1.000
5.5	0.023	0.0150	0.660
7.3	0.039	0.0230	0.590
9.7	0.063	0.031	0.492
11.6	0.091	0.039	0.429
13.4	0.126	0.046	0.355
15.0	0.168	0.054	0.321
16.4	0.215	0.061	0.284
17.6	0.262	0.068	0.260
18.5	0.307	0.075	0.244
19.4	0.353	0.081	0.229
20.2	0.399	0.088	0.221
21.0	0.447	0.093	0.208
26.0	0.936	0.130	0.139
31.8	2.10	0.175	0.083
37.2	4.390	0.224	0.051
43.3	10.100	0.287	0.028
48.3	20.000	0.349	0.017
51.1	30.400	0.388	0.013
52.7	38.00	0.400	0.011
56.4	70.50	0.445	0.0063
61.8		0.533	

* Relative to the Effective Permeability to Oil at Initial Water Saturation

Table 3 - Water-Oil Relative Permeability

Grayburg Formation: (Based on composite of three Amoco cores)

Water Saturation (percent)	Water Relative Permeability (fraction)	Oil Relative Permeability (fraction)
24.6	0.0000	1.0000
30.0	0.0008	0.5100
35.0	0.0014	0.2630
40.0	0.0043	0.1330
45.0	0.0117	0.0603
50.0	0.0294	0.0233
55.0	0.0650	0.0076
60.0	0.1260	0.0022
65.0	0.2100	0.0010
67.7	0.3200	0.0000

San Andres Formation: (Based on the composite of four cores from the Brock No. 10 Well)

Water Saturation (percent)	Water Relative Permeability (fraction)	Oil Relative Permeability (fraction)
23.8	0.0000	1.0000
25.0	0.0018	0.7100
30.0	0.0191	0.1640
35.0	0.0742	0.0420
40.0	0.1940	0.0123
45.0	0.3630	0.0045
50.0	0.6000	0.0021
55.0	0.9200	0.0016
56.4	0.9900	0.0000

Table 4 - Physical Properties of Gas from the Grayburg Formation

(Derived From Empirical Equations)

Pressure (psia)	Z-Factor (fr)	FVF (RCF/SCF)	Viscosity (cp)
1,777	0.395	0.00348	0.0589
1,600	0.365	0.00357	0.0472
1,400	0.332	0.00372	0.0395
1,200	0.304	0.00396	0.0328
1,000	0.297	0.00466	0.0267
800	0.492	0.00963	0.0199
600	0.675	0.01763	0.0137
400	0.804	0.03148	0.0105
200	0.909	0.07118	0.0098
15	1.000	1.00000	0.0094

Table 5 - Physical Properties of Oil form the Grayburg Formation

(Derived From Empirical Equations)

Pressure (psia)	Solution GOR (SCF/STB)	Oil FVF (RCF/SCF)	Viscosity (cp)
1,777	307.0	1.1551	2.726
1,600	307.0	1.1554	2.660
1,400	307.0	1.1556	2.592
1,200	307.0	1.1558	2.530
1,000	307.0	1.1560	2.484
979.6 = Pb	307.0	1.1561	2.479
800	241.4	1.1246	3.214
600	171.6	1.0921	4.179
400	106.0	1.0616	5.827
200	46.6	1.0339	9.010
15	0.0	1.0000	14.818

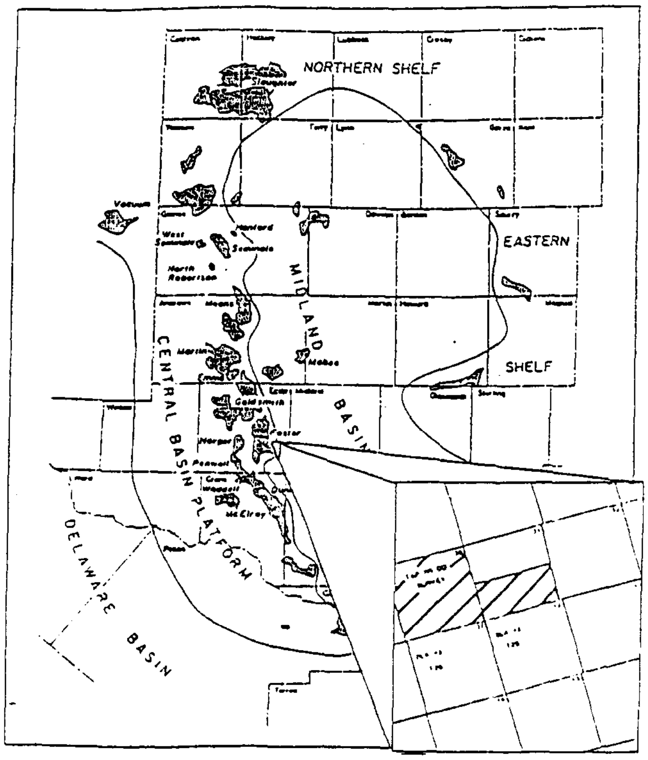

Figure 1 - Index Map of the Study Area
(After Bebout and Harris, 1990)

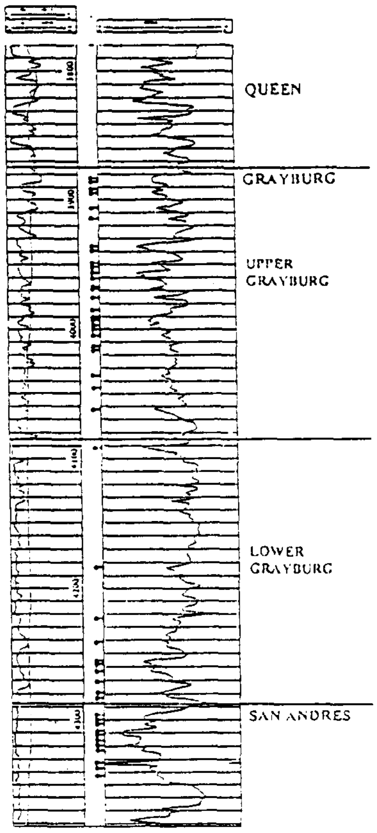

Figure 2 - Type-log of Well Drilled in Study Area

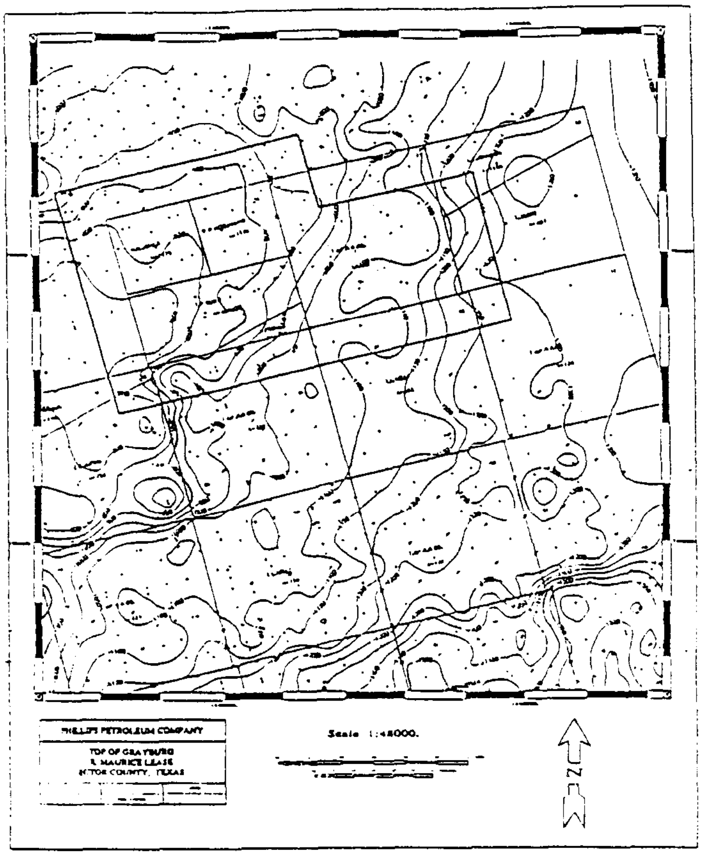

Figure 3 - Contour Map of Top of Grayburg Showing Location of the 3-D Seismic Survey

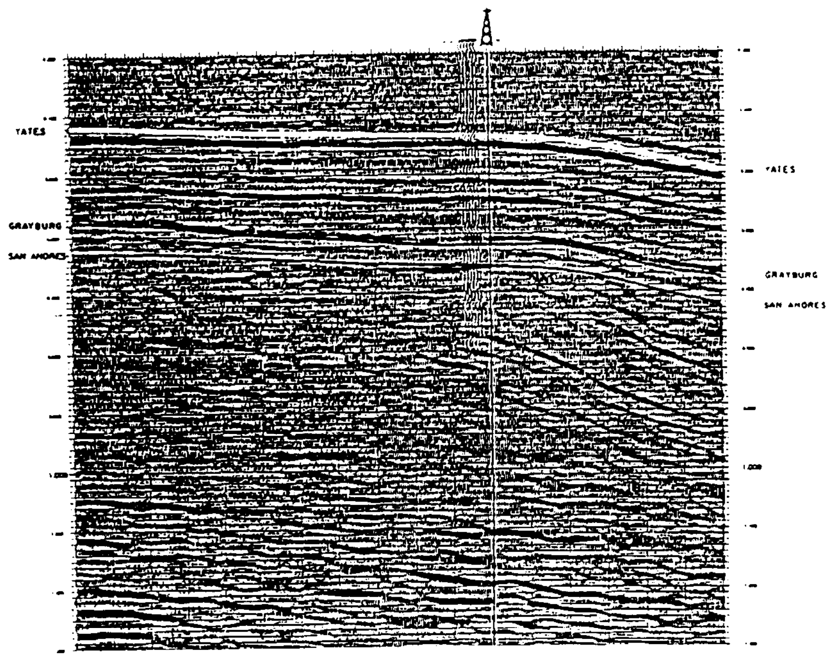

Figure 4 - East-West 2-D Seismic Section Through Study Area (Courtesy of M.D. Mark, Inc., and Great Western Drilling Company)

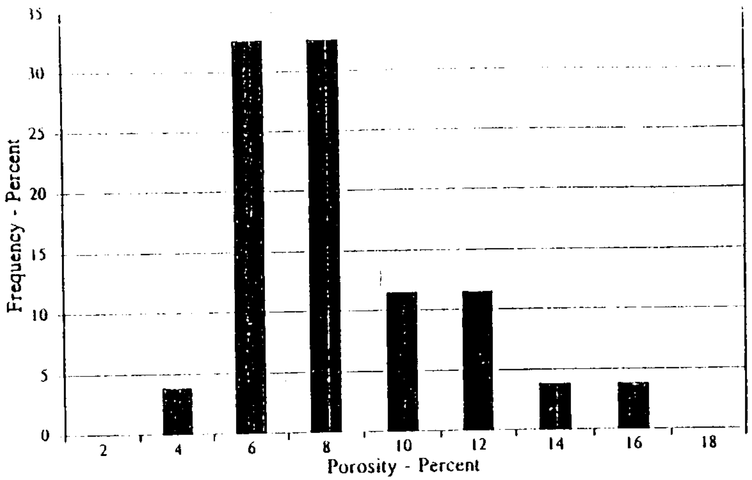

Figure 5 - Porosity Histogram
Foster Field Study, Grayburg Formation

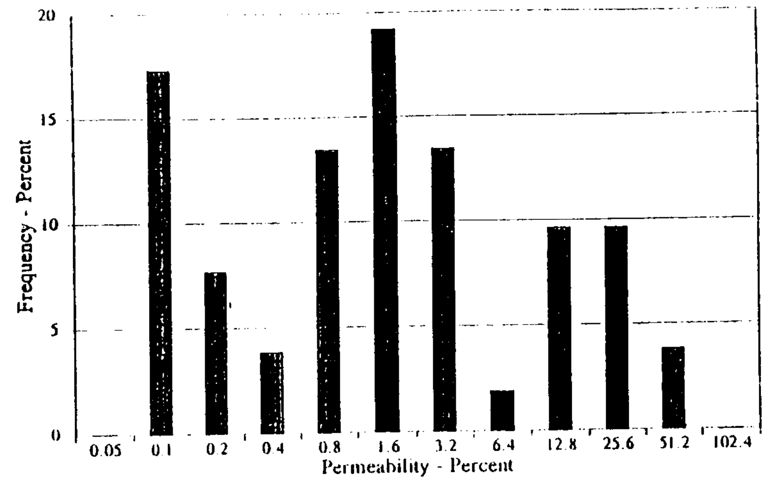

Figure 6 - Permeability Histogram
Foster Field Study, Grayburg Formation

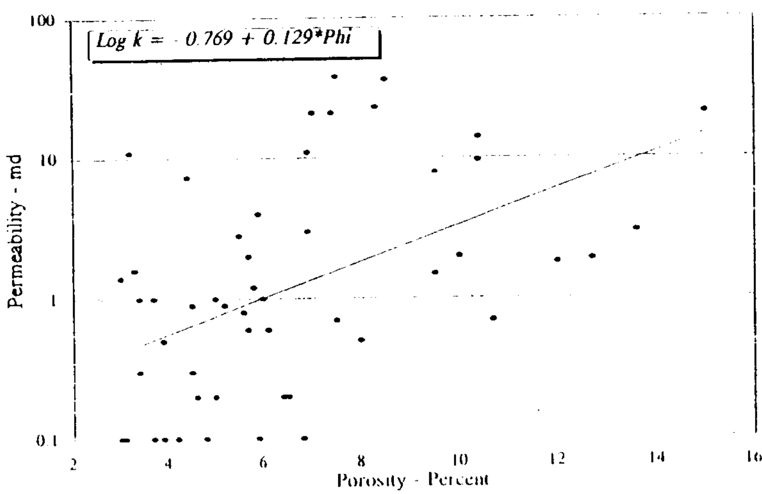

Figure 7 - Permeability vs. Porosity Correlation
Foster Field Study, Grayburg Formation

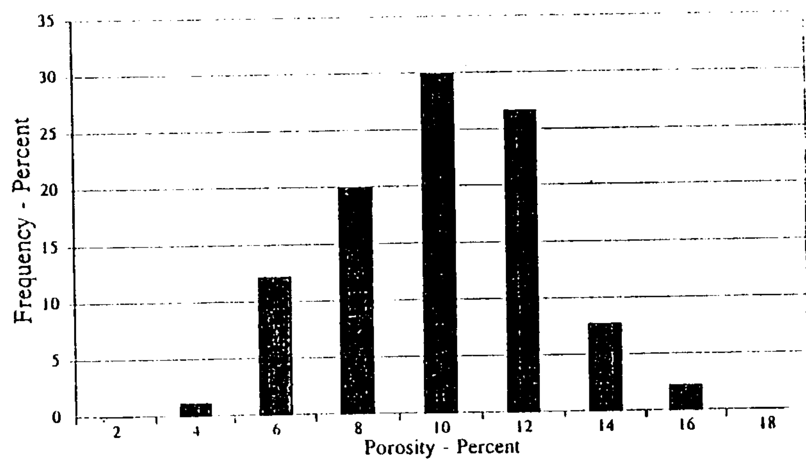

Figure 8 - Porosity Histogram
Foster Field Study, San Andres Formation

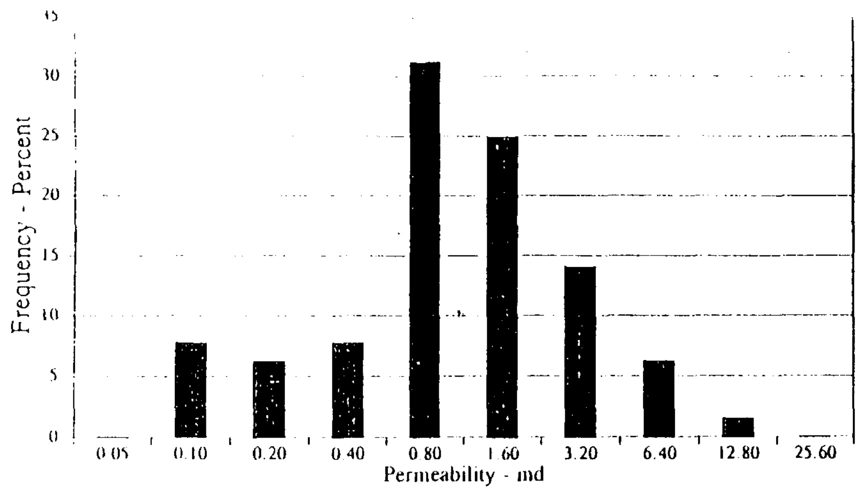

Figure 9 - Permeability Histogram
Foster Field Study, San Andres Formation

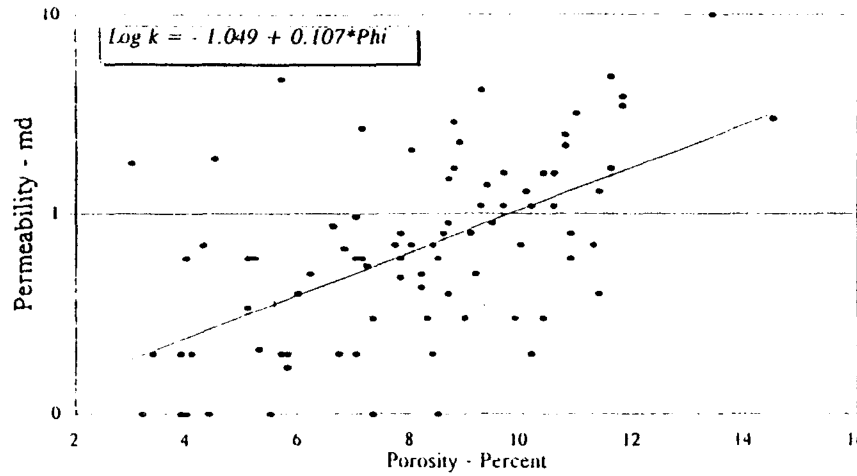

Figure 10 - Permeability vs. Porosity Correlation
Foster Field Study, San Andres Formation

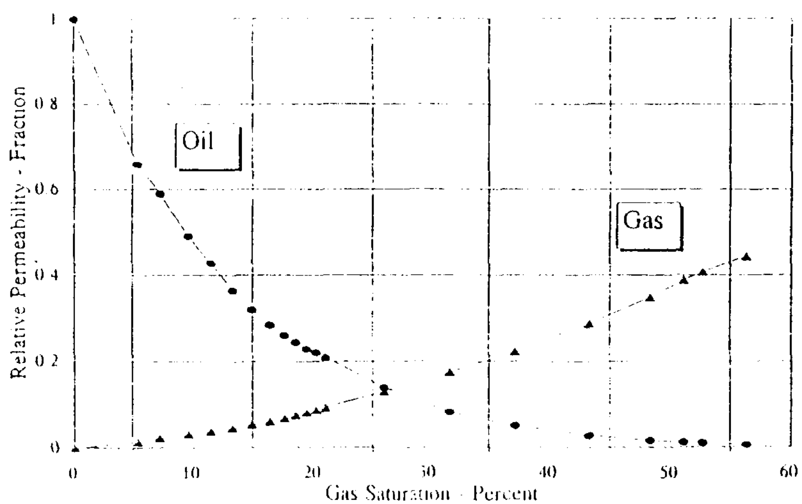

Figure 11 - Gas-Oil Relative Permeability
Foster Field Study, Grayburg and San Andres Formation

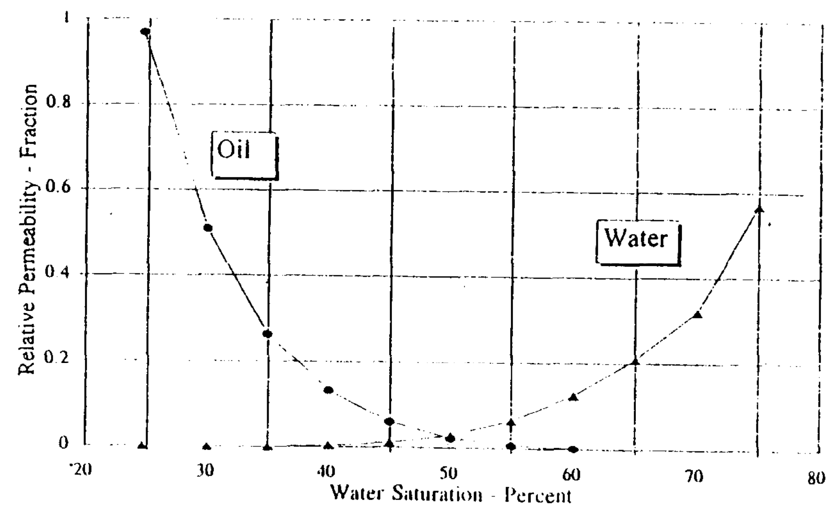

Figure 12 - Water-Oil Relative Permeability
Foster Field Study, Grayburg Formation

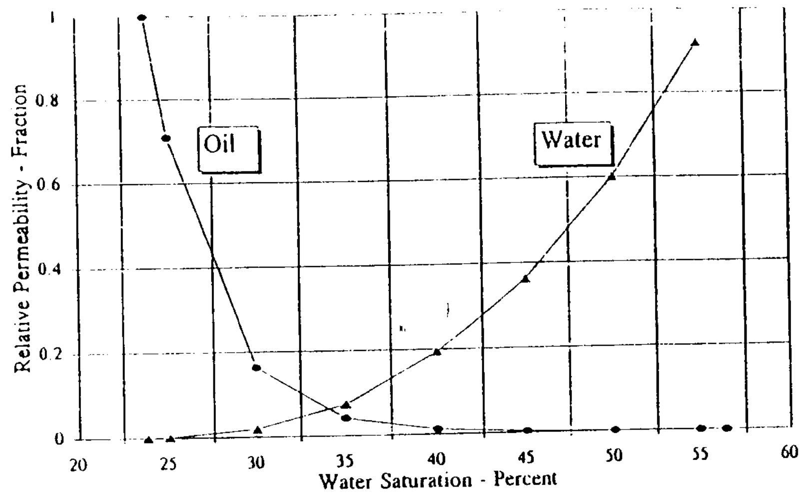

Figure 13 - Water-Oil Relative Permeability
Foster Field Study, San Andres Formation

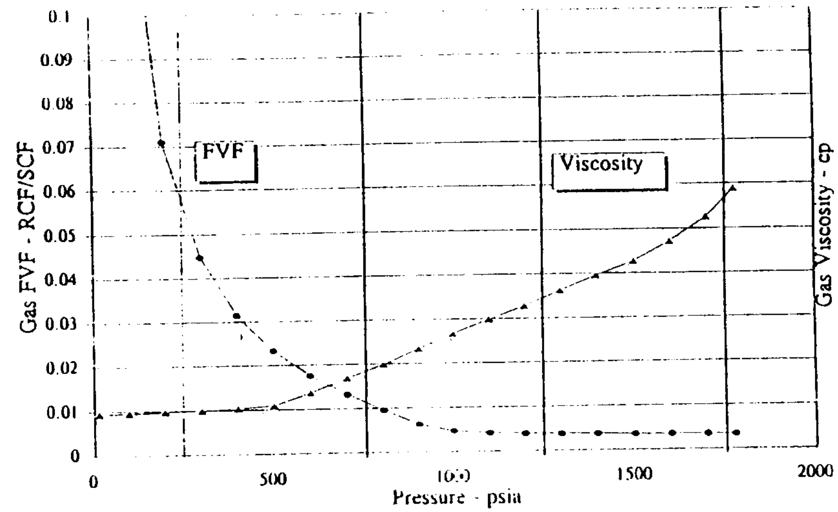

Figure 14 - Gas Formation Volume Factor and Viscosity vs. Pressure
Foster Field Study, Grayburg Formation

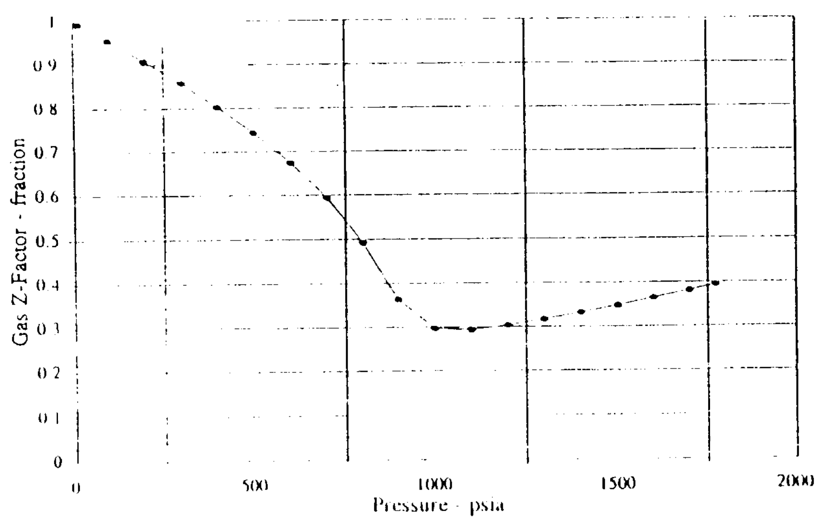

Figure 15 - Gas Z-Factor vs. Pressure
Foster Field Study, Grayburg Formation

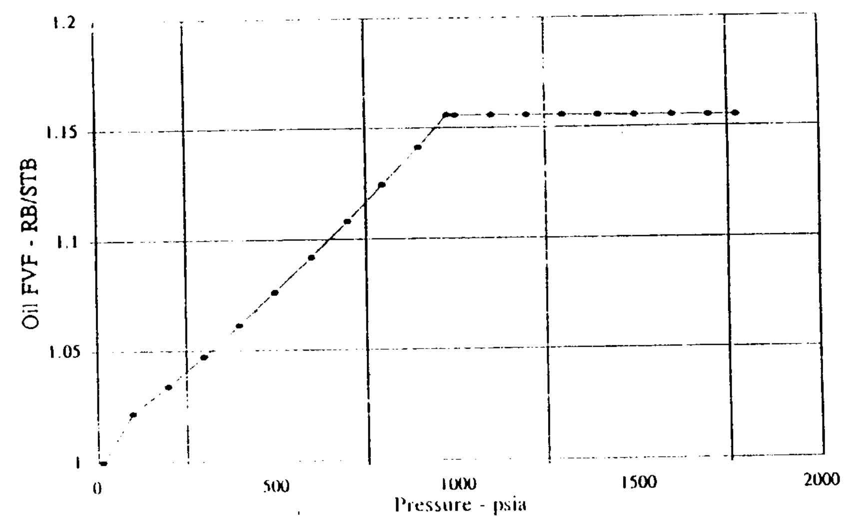

Figure 16 - Oil Formation Volume Factor vs. Pressure
Foster Field Study, Grayburg Formation

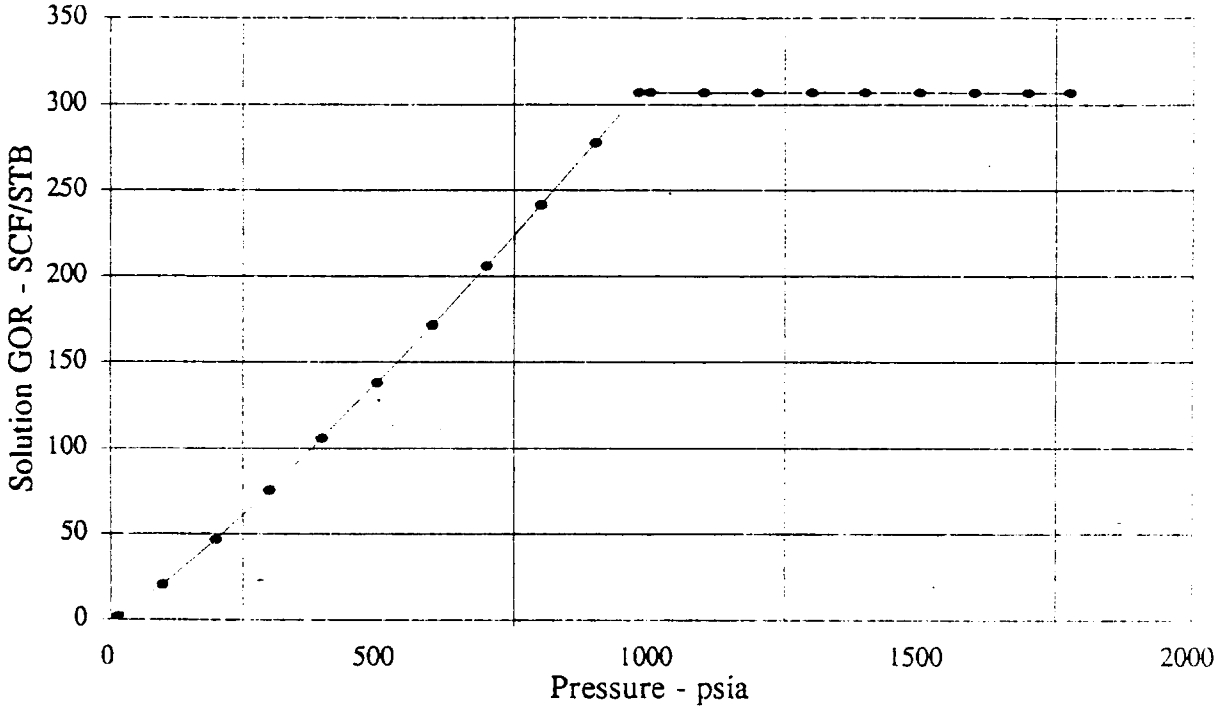

Figure 17 - Solution Gas-Oil Ratio vs. Pressure
Foster Field Study, Grayburg Formation

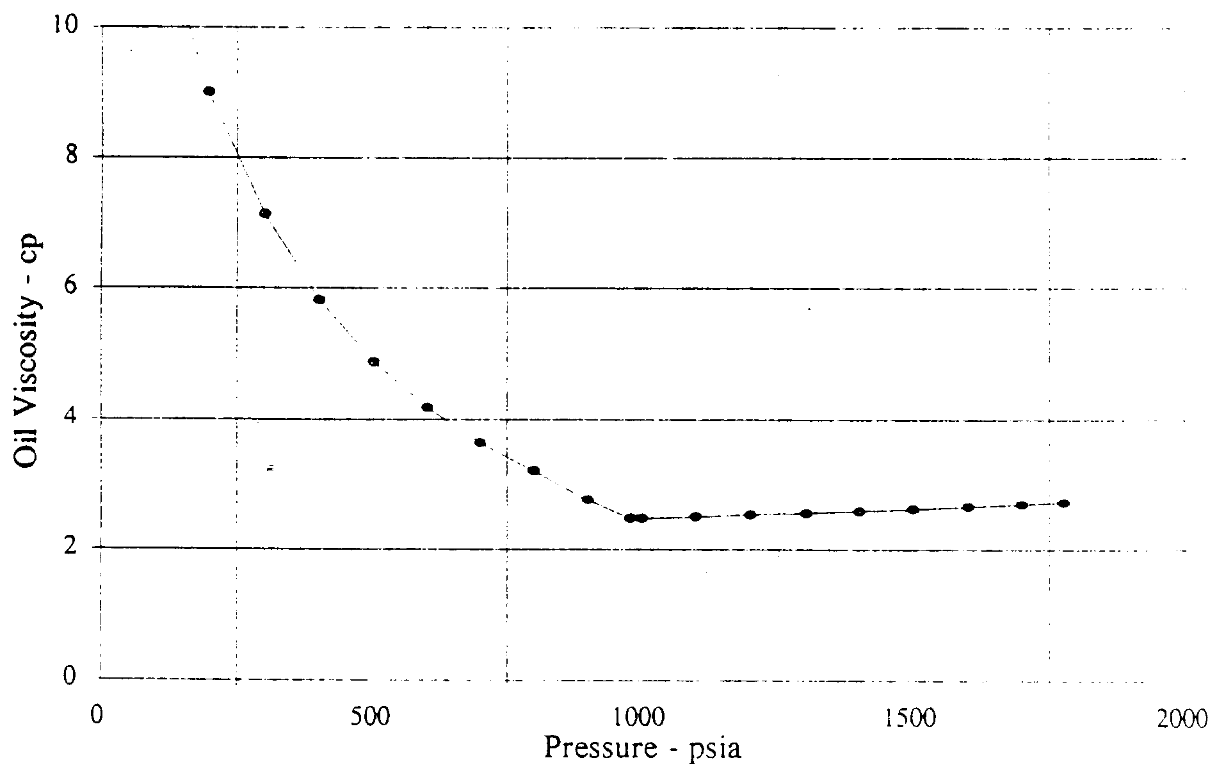

Figure 18 - Oil Viscosity vs. Pressure
Foster Field Study, Grayburg Formation