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COALINGA POLYMER DEMONSTRATION PROJECT

Fourth Annual Report
July 1978 — July 1979

Work Performed for the Department of Energy
Under Contract No. EF-77-C-03-1556

Date Published—September 1980

MASTER

Shell Oil Company
Houston, Texas

U. S. DEPARTMENT OF ENERGY

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COALINGA POLYMER DEMONSTRATION PROJECT

Fourth Annual Report
for the Period
July 1978 — July 1979

Van Schultz, *Principal Investigator*

Contributors:

J. E. Peterson (Reservoir)
M. T. Shannon (Production)
T. L. Killgore (Petrophysics)
D. D. Baxter (Facilities)
T. Bates (Facilities)
R. L. Miron (Facilities)
B. Zemel (Radioactive Tracers)
C. K. Huston (Polymer Quality)

Shell Oil Company
P.O. Box 831
Houston, Texas 77001
713/241-1646

H. J. Lechtenberg, *Technical Project Officer*
San Francisco Operations Office
1333 Broadway
Oakland, California 94612
415/273-7951

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SUMMARY

Shell Oil Company, in conjunction with the Department of Energy, is conducting a field demonstration test of displacement mobility control in the East Coalinga Field. The test is designed to determine the relative merits of polymer flooding and waterflooding in a medium viscosity oil reservoir. The injection pattern consists of four inverted 5-spot patterns and an updip area.

Water injection began in June 1976 and continued through April 1978. Polymer injection began in May 1978 and is ongoing.

The overall production performance for the pilot has been far less than expected. The current oil production rate is currently below the expected primary decline rate. The polymer injection rate which has been observed is substantially below original predictions and will increase the time required to inject the designed slug volume. The operation of the injection facilities during the first year of polymer solution prepared by the facilities has met or exceeded the stringent specifications imposed on the product.

Data from the sampling observation wells have not been definitive in monitoring the project performance. Low production rates from the selected completion intervals are common. Even after substantial injection of fresh water, many of the intervals still produce high salinity water. Minor changes in conductivity have been recorded in the logging observation well; however, the response recorded to date is not indicative of a large portion of the net pay being swept by the injection fluid.

Radioactive tracers were injected shortly after polymer injection was commenced. The occurrence of tracers has been monitored in the produced

fluids from wells in the pilot area. Response has been observed and is characteristic of a very heterogenous reservoir with response being observed at great distances in a relatively short time. A radiation response was also observed in the logging observation well; however, it was observed throughout the entire sand in contrast to the conductivity response.

Produced polymer concentrations above the minimum acceptable limit have been recorded in a number of wells. As with the radioactive tracers, wells substantially removed from the injectors have shown an indication of polymer.

A reservoir reassessment of the pilot area has been completed to include new data which was not available when the project was proposed. The petrophysical data indicates a substantially higher water saturation and a corresponding decrease in the oil saturation. Although the gas saturation remains essentially unchanged, current analyses of the data now suggest gas saturation (i.e., desaturation) further downdip in the reservoir. The isopach maps previously reported have been used to determine the reservoir volume.

The original oil saturation by sand has been estimated from three wells cored with oil and incorporated with other reservoir parameters by sand to determine the original oil in place. The cumulative primary production from Zone II has been determined for wells within the pilot area. From a production standpoint, the pilot area has been substantially depleted. However, since the primary production mechanism for the field has been gravity drainage, estimates have been made to take into account oil draining into the pilot area. With gravity drainage effects, the petrophysical and volumetric oil saturations are in better agreement.

The core data from wells in and around the pilot area have been reviewed and corrected for stressed conditions. The corrected oil saturation does increase downdip in the reservoir; however, the updip core data suggests an overall average oil saturation higher than the residual oil saturation assumed for gravity drainage. The average corrected oil saturation from core data could represent a minimum waterflood residual oil saturation due to flushing which occurred during the coring operations.

The reservoir reassessment has resulted in significant changes in the reservoir parameters and volumes for the pilot area.

Additional core flow experiments have been completed. These experiments have found that the ratio of divalent to monovalent ions present in the water used for the experiment affect the amount of clay swelling. With lower divalent to monovalent ion ratios, more clay swelling occurs. Since the injection water has a high divalent to monovalent ratio, clay swelling is not believed as severe as previously thought.

Experiments have also been completed to determine the relative permeability curves and endpoints using Coalinga crude and synthetic waters. The results of these experiments indicate a substantially lower relative permeability to the aqueous phase than previously thought. The lower aqueous phase relative permeability will substantially lower the calculated mobility ratio for the waterflood.

Experiments have also been conducted to determine the effect of Darley treatment as a completion fluid. The experiments indicate that the Darley treatment is capable of protecting clays from swelling by altering the wettability. This also results in a higher aqueous phase relative permeability.

Studies conducted in the laboratory and in the field have demonstrated that dilute Kelzan solutions are shear sensitive and that precautions are needed to prevent viscosity losses in the injection system and when sampling downhole for polymer quality.

INTRODUCTION

The Coalinga Field is located in the northern end of the San Joaquin Valley in Central California (Figure 1). The field has produced primary oil since 1901. The loss of solution gas and depletion of the reservoir pressure have increased the viscosity of the oil. As a result, waterflood projects in the field have been only marginally successful.

Shell Oil Company, in conjunction with the Department of Energy, is conducting a field demonstration test of displacement mobility control in the East Coalinga Field. The test is designed to determine the relative merits of polymer flooding and waterflooding in a medium viscosity oil reservoir. The results of the test will ultimately be used to determine whether or not waterflooding or polymer flooding will be expanded in the field.

The demonstration project has been organized into five phases which are: (1) Evaluation Phase, (2) Development Phase, (3) Water Injection Phase, (4) Polymer Injection Phase, and (5) Production Monitoring Phase. Field testing and selection of the pilot site were completed during the Evaluation Phase. The drilling of new wells, the reconditioning of old wells and the installation of the injection and production facilities were completed during the Development Phase. The Water Injection Phase began in June 1976 and continued through April 1978. Throughout this phase, production and injection data have been gathered. The Polymer Injection Phase began in May 1978 and is currently ongoing. The Production Monitoring Phase is scheduled to follow polymer injection. During this phase, water injection will displace the polymer slug through the reservoir.

The Immediate Pilot Area is shown on Figure 2. It consists of four inverted five-spot patterns and an updip area. Also shown is an area surrounding the pilot which is being monitored for response.

RESERVOIR DESCRIPTION

Although the reservoir description has been covered in previous reports^(1,2,3), it is briefly summarized here for completeness. Figure 3 is a type log for the Temblor Zone II reservoir in the project area. The formation averages 129 feet of net pay (refer to "Reservoir Reassessment" section) distributed among ten sands within a 350-foot gross interval. There are ten distinct sand intervals, each of which consists of several sand stringers. Well control does not permit mapping of individual sand stringers, but the sand intervals are correlative in the pilot area. The two upper sand intervals, E and F, were deposited in a marine deltaic environment and are considered floodable only in the pilot area. The remaining sands were deposited in a nonmarine alluvial channel environment and will be the major objective of any future expansion.

The Temblor Zone II formation in the pilot area dips to the southeast at 13 to 14 degrees (Figure 4). Outcrop excavation and subsurface studies of the alluvial sands in Zone II have established the direction of deposition from the northwest to southeast. Sand continuity can be expected over long distances in the direction of stream flow. But sand continuity, normal to the direction of channels, can be seriously disrupted by clay drapes or shale deposits which formed as the channels accreted in a northeasterly direction. Interchannel clay drapes and channel boundaries are barriers to fluid flow.

PROJECT PERFORMANCE

Production Performance

The overall production performance of the pilot has been far less than expected. The preinjection history, the waterflood performance, and the performance for the first year of polymer injection are shown on Figure 5. The oil production rate is currently below the expected primary decline rate and is due partially to the poor injectivity of the polymer slug and the lower than expected productivity of the wells.

The performances of the individual pattern production wells are shown on Figure 6. On this figure, Well 275-27 has been used instead of adjacent pattern producer Well 284-27. Well 284-27 has not been representative of this area. It is just now approaching the oil rate it was producing prior to an oil wetting treatment in early 1976. As is evident, none of the pattern producers have produced a substantial oil bank (except Well 275-27). The gross production from all wells shown is decreasing in response to the lower injection rates. Wells 1-5-26 and 4-6-26 continue to produce anomalously high volumes of water in comparison to the other wells. As has been reported earlier⁽³⁾, localized dumpflooding may have occurred in this area prior to the abandonment of other older wells.

The producing wells included in the production function for the pilot area (Figure 5) have been grouped into categories called priorities⁽¹⁾. In brief, the priorities are: the producing observation wells (Priority 1), the main pattern producers (Priority 2), wells updip of the five-spot patterns (Priority 3), and wells within the interior of the five-spot patterns (Priority 5). Wells in the area surrounding the Immediate Pilot Area are not included in the production function and are referred to as Priority 4.

The monthly data (oil, gross, watercut, and well count) for Priorities 1, 2, 3, and 5 are shown on Figures 7 through 10.

Priority 1 wells (Figure 7) were drilled specifically for the polymer project as producing observation wells. These wells were all Darley treated⁽¹⁾ prior to placing them on production and have historically produced at very low gross rates from the selected sands. These wells have not been definitive in monitoring the performance of the flood. From July 1976 through May 1979, these wells have produced only 3 percent of the total gross fluid withdrawals from the Immediate Pilot Area.

The Priority 2 wells (Figure 8) are the main pattern producers. In this priority, seven (7) wells were on production prior to the start of the full scale injection. Five additional wells were drilled and placed on production in late 1975 and early 1976 and one of the existing wells, 74-27, was abandoned. All but two of the Priority 2 wells currently on production were Darley treated⁽¹⁾ to prevent damage due to clay swelling. Two of the wells in the north and northeastern portion of the pilot, Wells 1-5-26 and 4-6-26, have produced anomalous high volumes of water since their completion. As shown on Figure 8, oil production after full scale injection was commenced, is approximately equal to the preinjection history even though the active well count has been increased by four.

The production for the Priority 3 wells, updip of the five-spot patterns, is shown on Figure 9. Response to water injection has been observed in this priority. The well count has increased from 6 to 11 by returning to production wells which had been shut in. The well count increase is similar

to that for Priority 2, but the oil production response has been very noticeable. It is also evident that when the injection rate was decreased, the overall production response decreased.

The production performance for the Priority 5 wells is shown on Figure 10. Since 1972, the well count has been decreasing. Shortly after full scale injection was commenced into the pilot area, additional wells were abandoned to minimize flow distortion within the patterns. Of concern in this priority are the high gross production and high water cut being produced prior to starting full scale injection. Dump flooding has been reported in and near the pilot area but its extent was unknown. Portions of the five-spot patterns could have been dump flooded to a substantial degree since the recent water saturations calculated for the pilot area are higher than previously thought. The recent water saturations for the pilot area are discussed later under "Reservoir Reassessment". The wells which are currently on production in this priority are Wells 34-27, 58-27, 92-27, and 294-27.

Injection Performance

Throughout the waterflood portion of the project, pressure falloff surveys have been conducted on the injection wells. The data obtained from these surveys have indicated a low permeability-thickness product for the injection wells as summarized on Table 1.

In anticipation of lower polymer slug injection rates, the water injection was reduced in March 1978 (see Figure 5). Polymer injection was commenced in May 1978 at a rate of 400 barrels per day per well. After approximately one and a half months of polymer injection, the maximum wellhead pressure constraint of 600 psig was reached at three of the four injectors, and the polymer injectivity dropped significantly in these wells. In the fourth well,

2-9-26, the injectivity has declined gradually. The injection rates and bottom hole injection pressures are summarized by well on Figures 11 and 12.

From the radioactive tracer surveys run during the water injection phase and during the first 11 months of polymer injection in the project, cumulative water and polymer injection by sand has been summarized on Tables 2 and 3. Also shown is the injection as a percentage of the moveable pore volume. During water injection, the Hx sand has taken a significantly larger volume than the other intervals.

An extensive remedial program is now underway in one of the poorer polymer injectors. (15-9-27) to determine the cause for the drop in injectivity and whether or not injectivity can be restored. However, even if the injectivity can be restored to the initial polymer injection rate of 400 barrels per day per well, the time required to inject the designed polymer slug volume will exceed 5 years. This is substantially longer than the 18 months originally estimated and provided for in the Milestone Chart. To arrive at the timing for the Milestone Chart, it was predicted that the minimum polymer injection rate would be 1000 barrels per day per well.

Injected Polymer Quality

Although the polymer injectivity and production performance have been far less than expected, the operation of the injection facilities during polymer injection has been essentially uninterrupted. The quality control of the polymer solution prepared by the facilities has met or exceeded the stringent specifications imposed on the product. The specifications and typical values of the polymer solution are summarized on Table 4.

SAMPLING OBSERVATION WELLS

Data from the sampling observation wells have not been definitive for monitoring the flood performance. The low production rates observed in many of the zones indicate the producing wells may not be responding to injection. In addition, adjacent zones within the same well often produce at similar rates and salinities, which may indicate the sands are in communication. A summary of the performance of the individual observation wells is as follows:

Well 1-7-26

1-7-26 has been shut in since May 1978 and has just recently been returned to sampling status.

Well 1-9-26

F Sand

Water salinity produced from this zone had been constant (~1700 ppm) from June 1978 until mid-August 1978 when the salinity increased to 2300 ppm. Polymer injection in Well 2-9-26 could be displacing water in this zone. However, no increase in the production rate has been associated with this salinity increase. The production rate has averaged 1 barrel per day gross and no oil.

Gc Sand

No changes in salinity have been observed in this zone with the produced water salinity averaging 1200 ppm. Producing rates have gradually declined from 12 barrels per day gross and 2 barrels per day oil to 4 barrels per day gross and 1 barrel per day oil in December 1978.

Gd Sand

The produced water salinity has remained constant at 1500 ppm. As was previously reported⁽³⁾, the Gc and Gd sands may be in communication due to similar salinities. However, the production rate of the Gd sand has been slightly lower than that of the Gc, ranging from 3 to 6 barrels per day gross and no oil.

Well 15-8-27

Workover activities in the adjacent injector, 15-9-27, have been in progress since March 1979 to determine the cause of poor polymer injectivity and whether or not injectivity can be restored. Recent salinities and corresponding production rates may reflect the interruption of injection.

Gc Sand

Salinity has remained constant at 1100 ppm during polymer injection. However, the gross production rates have been erratic, ranging from 1 to 6 barrels per day gross with 0 to 1 barrel per day oil.

Gd Sand

Decreasing salinity has been observed in the Gd sand. The produced water salinity has decreased from 9000 ppm in mid-July 1978 to 7500 ppm in September 1978. Response to injection may have been observed at the end of July and again, in the beginning of September. In July, the G_d sand produced 7 barrels per day gross and 5 barrels per day oil. Prior production rates averaged 4 to 7 barrels per day gross and 0 to 2 barrels per day oil. These rates also followed the July test data. In September, the production rate was 7 barrels per day gross and 6 barrels per day oil but was again followed by lower oil production rates (0 to 1 barrel of oil per day). The increased oil production rate may indicate the generation of an oil bank due to injection or that the test data was anomalous.

Hw Sand

A decreasing salinity trend has also been observed in this zone with salinities decreasing from 8000 ppm to 5900 ppm. Production rates from this interval have been high compared to intervals in the other observation wells. The production rates have ranged from 9 to 14 barrels per day gross and 0 to 2 barrels per day oil.

Well 16-7-27

When sampling zones are changed in this well, the new zone has an initial salinity equal to the ending salinity of the previous zone. As the interval is produced, the salinity gradually changes until the zones are again changed. Anomalous points are present, but in general the increasing trend is apparent. There is a slight possibility that all three zones (Gd, Hw, Hx) may be in communication.

Gd Sand

The produced water salinity has increased from 8500 ppm in September 1978 to 10,000 ppm in April 1979. Response to injection may have been observed in October 1978 with a test indicating 7 barrels per day gross and 6 barrels per day oil. Previous production rates averaged 2 barrels per day gross and 1 barrel per day oil. Rates after the October 1978 data were 3 to 4 barrels per day gross and 2 barrels per day oil. The possible response which was observed in October 1978 occurred within a 12 day period since production tests, both before and after, indicate lower rates of both gross and oil. This could also imply that the test data was anomalous.

Hw Sand

Produced water salinities from this zone have been higher (10,000 ppm) than observed in the other observation wells. The produced water salinity

is not indicative of Darley treatment water used in the completion of 16-7-27 since previous produced water salinities before polymer injection averaged 8000 ppm. It appears that the injected fluids may be displacing reservoir fluids, but no oil bank response has been observed in this zone. The production rates have averaged 5 barrels per day gross and 2 barrels of oil per day.

Hx Sand

Produced water salinities from this zone have been erratic with changes from 9000 ppm to 6650 ppm back to 9500 ppm in one month's time. No sustained trend has been observed. Production rates have varied from 2 to 6 barrels per day gross and 1 barrel per day oil.

LOGGING OBSERVATION WELL

Minor changes in conductivity have been recorded in the logging observation well, 16-6-27, since the start of the Polymer Injection Phase in May 1978. Dual induction logs have been run once a month and any conductivity changes recorded by the logs would indicate changes in the water salinity and/or oil saturation. Conductivity changes in sand stringers of several sand intervals (Gc, Gd, Hw, Hx, and Js) were observed during the period of May 1978 through April 1979 with the first changes occurring in July 1978, three months after commencing polymer injection. The changes recorded are shown on Figure 13.

The September 1978 changes in conductivity in conjunction with the salinity changes observed in the adjacent sampling observation well, 16-7-27, suggest an eight percent increase in water saturation in the Hw and Hx sands when compared to the May 1978 pre-polymer log. Since September 1978, the G_d sand is the only zone which has been sampled in Well 16-7-27. A 15 percent increase in oil saturation has been calculated from the conductivity differences of the May 1978 log and the April 1979 log. Although the conductivity changes were minor, a saturation increase is calculated because the produced water salinity from the Gd sand in Well 16-7-27 has increased from 8500 ppm to 10,000 ppm from May 1978 to April 1979. However, production response has not been observed in the G_d zone of Well 16-7-27 which is substantially farther away from the injector than Well 16-6-27. Saturation calculations have not been made for the Gc and Js sands since changes in the water salinity of these sands cannot be estimated from the sampling observation well in this quadrant of the pilot.

RADIOACTIVE TRACERS

As during the Waterflood Injection Phase, four radioactive tracers were injected with the polymer solution in the four injection wells on May 15, 1978. The tracers were injected using an instantaneous one-shot, or "burst", method. In this second tracer program, tritiated water was substituted for iodide in Well 2-7-26. Iodine-125 was substituted for tritium in Well 2-9-26. About one curie of sulfur-35 was used in Well 15-9-27 as compared to 150 millicuries injected earlier during the water injection. One hundred millicuries of cobalt-60 were injected into Well 15-6-27 versus 20 millicuries during the water injection.

Cobalt-60 was chosen as a tracer despite its apparent failure during the waterflood for three reasons:

- 1) Re-examination of earlier data left some doubt as to how much of the complex cobalt cyanide had actually been synthesized by our supplier.
- 2) It was concluded on work done elsewhere and further laboratory experiments at Shell Development that the cobalt cyanide complex should be a suitable tracer in the Coalinga environment.
- 3) Shell Development also developed a far more sensitive method of detecting and identifying the cobalt-60 tracer.

Well 2-7-26

Four curies of tritiated water were injected. The first response was noted in approximately one month in Well 114, about 2200 feet southwest from the injector. Subsequent response has been recorded only in Wells 16-7-27,

1-9-26, and 1-8-26, all south and west of the injector. This is quite different from the waterflood tracer response. The results are shown on Figure 14.

Well 2-9-26

One curie of iodine-125 was injected. The results, corrected for half life, are shown on Figure 15. The first response was recorded in Well 120-27, about 2700 feet northwest from the injector, six weeks after injection. The response in the nearest well, 1-9-26 was not noted until August 26, more than three months after injection of the tracer. Response to this injector was considerably slower and different than before. Three of the wells north of the injector, Wells 92-27, 1-8-26, and 3-8-26, now show some response. The response is nonradial and strongly skewed to the northwest.

Iodine-125 is an isotope emitting a relatively soft gamma and having a half life of only 60 days. It was chosen here for a combination of reasons:

- 1) Price, availability, and the relatively soft gamma emitted permitted the use of a full curie.
- 2) Shell Development developed a very simple enrichment procedure which allowed enrichment by a factor of 1000 by simple ion exchange procedure.
- 3) It has a well defined characteristic gamma spectrum which could be used to positively identify its presence from other sources of radioactivity. As a result, a useful tracer life of 12 to 18 months could be anticipated.

Well 15-6-27

One hundred millicuries of cobalt-60 was injected in the form of the hexacyanocobaltate ion. The 100 millicuries limit was dictated by safety in handling as well as other considerations.

Response to the cobalt injection has been recorded in a large number of wells as shown on Figure 16. Some of the wells responded quite early. There was also some indication that the cobalt injected with the waterflood is still responding at this time. The response was widespread and relatively rapid. Response was noted as far as Well 137-26, about 3000 feet from the injector, within 3 weeks. A noteworthy feature of this response was the low level of cobalt in the produced samples. This indicates a much higher degree of dilution than was evident from any of the other tracers.

The cobalt-60 was separated, as was the iodine-125, by simply passing the produced water sample through a small ion exchange column. The entire ion exchange column was then counted in a sodium iodide well-crystal. The cobalt-60 was counted by taking advantage of the difference in energy between its gammas and those of the iodine. Like iodine, cobalt-60 has a very distinct gamma spectrum which is used to identify and separately count the cobalt.

Well 15-9-27

One curie of sulfur-35 was injected in this well. The results are shown on Figure 17. Very early response was recorded within one week in Wells 1-5-26 and 1-8-26. Somewhat later response was noted in Wells 58-27 and 276-27. The response is quite different from the previous response. As shown, the recent response is skewed very strongly along a line from the northeast to the southwest.

No enrichment of samples was performed. The sulfur-35 was counted in the liquid scintillation counter along with tritium. Because of the difference in energies, the tritium and the sulfur betas could be distinguished from each other by the counter. Since neither tritium nor sulfur-35 has a

gamma, they did not interfere with the other tracers used. The iodine-125 and cobalt-60, used as tracers in other wells, did not interfere with the sulfur-35 at these levels.

Summary of Tracer Response

The tracer responses shown on Figures 14 through 17 are shaped by the lack of response in neighboring wells as well as by the relative arrival times at the responding wells. Three major conclusions stand out from the response data:

- 1) For most of the injectors, the geographic response is represented by a few narrow channels radiating asymmetrically from the injector.
- 2) There is very little effect of one injector on the response of other injectors. They each appear to act independently, as though they were injecting into separate horizons.
- 3) No duplication of flow was observed from the waterflood and polymer flood radioactive tracer programs. Since many more samples were analyzed for the polymer flood tracers, it was easier to define the breakthrough pattern for each tracer.

The tabular results of the analysis for each of the four tracers is summarized on Table 5. Where two sample dates are given, this means that both of the samples were combined and analyzed as one. This was done to increase the sensitivity for cobalt and iodine. The tritium and sulfur-35 were analyzed separately. Within the statistics of counting, a zero indicates that no tracer was detected. The designation N/A means not analyzed. The actual data are given more significant figures than can be statistically justified so that they will stand out from the zeros. Based on volume of sample analyzed,

efficiency of counting, and background count rate, the limiting sensitivity for counting Co-60 and I-125 is 0.001 μ Ci/bbl. For S-35, it is 0.1 μ Ci/bbl and for tritium, it is 0.3 μ Ci/bbl.

Logging Observation Well Response to Tracer Injection

The radioactive cobalt-60 injected in Well 15-6-27 was monitored in the logging observation well, 16-6-27, by running gamma ray logs and monitoring an increasing or decreasing radiation level in each sand. Gamma ray logs were run in Well 16-6-27 beginning June 13, 1978, one month after the radioactive cobalt was injected. The well was then logged once a week until October 12, 1978.

First observation of increasing radiation occurred June 27 which was one and a half months after injection. The increase in radiation observed was fairly uniform (Figure 18). The amount of radioactivity increased uniformly in all sands until August 15. After this date the level of gamma radiation continually decreased until October 12, 1978. The log on this date indicated the same gamma radiation as the pre-tracer injection base log.

A definite tracer front was recorded moving past 16-6-27. The gradual increase and then gradual decrease with time is what would be expected. But it is surprising that the same amount of radioactivity (as defined by the amount of separation from the base gamma ray log) was nearly equal in all sands at a specific time. This is contrary to the idea of small barriers and channels existing in individual sand members across the field and also that flow around Well 16-6-27 has been restricted or hampered.

PRODUCED POLYMER CONCENTRATION

Produced fluids from the pilot wells have been monitored not only for the presence of radioactive tracer but also for polymer. Polymer concentrations exceeding 10 ppm have been recorded at a number of wells in the pilot area (see Table 6). Data below 10 ppm (the minimum acceptable limit) is not considered a real indication of the presence of polymer. The top sampling zone (Gd) in Well 16-7-27 has shown one sample of 88 ppm polymer and has consistently provided concentrations of approximately 20 ppm. The other wells have indicated the presence of polymer, but only in a few samples. Well 16-7-27 is currently being sampled from just the top zone in an attempt to produce polymer of sufficiently high enough concentration to be able to determine if the polymer solution deteriorates after transport through the reservoir.

A similarity is observed in the locations of tracer response and produced polymer concentrations exceeding 10 ppm (Figure 19 and 20). Most of the tracer and polymer response have occurred in Section 27, the updip area. More desaturated zones are present updip which would provide less restrictive flow paths for both the tracer and polymer. A few desaturated intervals exist downdip in some of the lower sands (Js, Jv) which might explain the appearance of tracer and/or polymer in wells southeast of the pilot in Section 26.

RESERVOIR REASSESSMENT

The petrophysical reevaluation of the pilot area has been completed. New data, not available when the project was proposed, have been incorporated into this study. Updated information concerning shale content (Qv), formation water salinity (from produced samples taken since early 1976), reservoir parameters (from core material from Well 16-6-27), and modern log suites (dual laterologs, density-neutron logs) have been used. Wireline logs from wells in the pilot area have been evaluated by sand to determine the average porosity, and the average water, gas, and oil saturations.

Porosity

To determine the average porosity by sand, data from 39 wells were used. Porosity was calculated using the following equation:

$$\phi = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$$

where ρ_{ma} and ρ_f were assumed at 2.65 gm/cc and 0.992 gm/cc respectively, and ρ_b was taken directly from the density log. Porosity was determined for each bed in a given sand and then thickness-weighted averaged for each sand in a given well. The porosity values ranged from 0.18 to 0.30 as shown on Table 7. For each sand, a thickness-weighted average porosity was also determined as shown.

Water Saturation

Petrophysical data from 16 wells in the pilot area were used to calculate the water saturation by sand using the Waxman-Smiths shaly sand equation:

$$S_w^{-n^*} = I = \frac{R_t (1 + R_w B Q_v / S_w)}{R_o (1 + R_w B Q_v)}$$

The sands (E through Jv) in each well were subdivided into individual beds. For each individual bed, the porosity was calculated and a corrected resistivity (corrected for borehole and invasion effects) was determined. The resistivity of water-saturated rock (R_o) was calculated using the following equation:

$$R_o = F_a R_w = \frac{F^* R_w}{1 + R_w B Q_v}$$

where $F^* = 1/\phi^{m^*}$. For each of these wells, a specific formation water salinity (R_w) was assigned (4650-9000 ppm) based either on the produced water salinity from the well or produced water salinity from nearby wells. The formation shale content (Q_v) has been determined by sand from core analysis and has been assumed to be constant for that sand throughout the pilot area. The range of Q_v is from 0.06 to 0.46 milliequivalents per milliliter of pore volume. In addition, m^* and n^* (cementation and saturation exponents, respectively) were determined by core analysis and average 1.69 and 1.80 respectively. These values were assumed constant for all sands throughout the pilot area. Having measured R_t and calculated R_o , the resistivity ratio (I) was determined and the water saturation found from a Waxman-Smiths saturation chart for a saturation exponent (n^*) of 1.8. The water saturations determined for each sand in the wells analyzed are shown on Table 8. The saturation of each bed was multiplied by the number of feet in that bed and the products for the individual beds summed and divided by the total net permeable footage in that sand. The porosity-thickness weighted average for each sand has also been determined and is shown.

These water saturations are higher than those reported in the Third Annual Report⁽³⁾ since they include all net permeable sand. Previously, reported data eliminated from the average and summary any permeable sand having a water saturation greater than 65 percent.

Gas Saturation

To completely and accurately define the saturations present in the Coalinga Polymer Project, it was necessary to determine the amount of gas (desaturation) in the reservoir. The presence of gas can be seen from density-neutron logs, especially in the updip area.

All wells with density and neutron logs were used. Gas can be seen from these logs when (using the same porosity scale) the neutron curve reads lower than the density curve; i.e., a crossover is present. The density log responds with a higher porosity reading due to the lower density of gas as compared to oil or water. Conversely, the neutron log reads a lower porosity due to the lower hydrogen index of gas again compared to oil or water. A fan chart using bulk density and neutron porosity can be constructed which gives the percentage gas saturation and true porosity.

A fan chart was constructed using Coalinga parameters (Figure 21). The obvious desaturated zones, using the theory of crossover; were crossplotted on the chart from twenty wells in the pilot area. Gas saturations ranged from less than 10 percent to greater than 90 percent in individual sands in the updip area. But some zones with very low gas saturations could be missed using the crossover technique due to the effect of shale on the neutron log.

The neutron log is more affected by the presence of shale than the density log. This is due to the neutron log detecting the hydrogen of the bound waters in the shale, in addition to the hydrogen of the liquid reservoir

components. As a result, the neutron log will give a higher porosity value in a shaly zone than it would in a clean zone. This higher porosity will decrease or mask the crossover in a gas zone in such a way, that gas may be present but a crossover will not be observed.

A chart of gamma ray versus porosity separation of the neutron and density curves was constructed (Figure 22). This minimizes the effect of shale on the neutron log response because the gamma ray is also affected by shale. Gas zones, even those with low gas saturation, may appear anomalous on this crossplot. Zones containing no gas will trend in a straight line, so that a liquid line can be drawn. All points plotting above this liquid line should contain gas (allowing for data scatter).

This gamma ray-porosity separation crossplot was used, along with the fan chart, to define all zones which contained desaturation. All anomalous points from the gamma ray-porosity separation chart were crossplotted to give percent desaturation. The percent gas saturation in each individual bed was multiplied by the number of feet in that particular bed, summed over all the beds containing desaturation in a sand, and then divided by the total net feet of permeable sand in that sand (see Third Annual Report for isopach maps of each sand). This resulted in a percent gas saturation for the entire sand as shown on Table 9.

Four dual-spaced neutron logs were run in September, 1978, to locate the desaturated zones and to compare the location and thickness of these zones with those present when the well was drilled. The wells logged 4-13-26, 3-11-26, 285A-27, and 16-6-27. As can be seen in Figures 23 through 26, most of the desaturated zones present when the wells were drilled (1967 and 1975)

are still present and have increased in thickness, and additional zones now appear. This indicates that injected water has not resaturated the desaturated zones as might be expected. At the present time no method exists to obtain a percentage gas saturation from the dual-spaced neutron logs, but the presence of gas can be delineated.

Reservoir Volume

The net permeable sand isopach maps, included in the Third Annual Report⁽³⁾, have been planimetered for the pilot area to determine the reservoir volume. The maps represent not just net pay but total permeable sand. The result of this work is summarized on Table 10. As shown the reservoir volume for all sands is 19,145 acre-feet. Planimetering the acreage represented by the boundaries of the Immediate Pilot Area (Figure 2) yields approximately 149 acres. This acreage is also supported by the previous simulation grid used for the Immediate Pilot Area.

Average Saturations

To obtain average saturations for the pilot area, the average water and gas saturations by sand were multiplied by the planimetered reservoir volume and average porosity for that particular sand, summed, and divided by the total pore volume of the pilot area. Table 11 shows the average saturations determined for the pilot areas as well as the data for the individual sands. The oil saturation has been calculated as one minus the water and gas saturation since the oil saturation cannot be calculated directly by petrophysical methods.

Initial Oil Saturation

Data are not available from the early 1900's from which the initial oil saturation in the reservoir can be determined. However, during the history of the field, three wells were cored with oil and the cores analyzed under

unstressed conditions. These cores should approximate the irreducible water saturation since any water above the irreducible water saturation should have been displaced by the coring operation. The difference between unity and the water saturation has been assumed to be the initial oil saturation. Using this assumption and the unstressed core data, the approximate initial oil saturations by sand are summarized on Table 12. The data ranges from 51.4 to 76.3 percent. These estimated initial oil saturations and the planimetered pore volumes by sand have resulted in the calculated volumetric average initial oil saturation of 66.0 percent as shown on Table 13. Assuming an initial formation volume factor of 1.07 RB/STB, it is estimated the Immediate Pilot Area contained approximately 22,286,000 stock tank barrels of original oil in place (23,857,000 reservoir barrels).

Primary Production History

The East Coalinga Field (Zone II) has been on production since 1901. However, early production records for the allocation of production to Zone II are not available. A production map from 1958, which allocated the production by zones based on the footage open in each zone, has been used to determine the cumulative oil production for Zone II in the pilot area. Production since 1958 has been determined from the monthly individual well reports and as of July 1, 1976, the total cumulative oil production from Zone II in the Immediate Pilot Area is estimated to be 16,424,000 stock tank barrels. From a depletion standpoint, it is estimated that the pilot area has produced approximately 73.7 percent of the original oil in place.

Gravity Drainage Effects

It has been reported that the East Coalinga field produces by gravity drainage. Early in the life, there was probably some contribution from deple-

tion drive; however, it is not believed to be significant. The oil saturation calculated assuming a depletion drive reservoir does not take into account the effect of oil draining into or out of the area due to gravity drainage.

To estimate the effect of oil draining into the Immediate Pilot Area due to gravity drainage, we have taken the "black box" approach as shown on Figure 27. We have assumed, however, that oil does not move out of the area.

Just how much oil has actually drained into or out of the area is unknown. But if we assume we have an "infinite" source of oil updip, we can calculate the free fall drainage rate for the cross sectional area available as follows:

$$q_o = \frac{1}{887.2} \frac{K_{oi} h W (0.433 (\gamma_o - \gamma_g)) \sin \alpha}{\mu_{oi} B_{oi}}$$

Where W = 1800'

q_o = drainage rate in BPD

h = 128.8'

K_{oi} = 300 md

γ_o = .92

γ_g = .00 (liquid filled)

α = 13°

μ_{oi} = 18.5 cps (at reservoir conditions)

B_{oi} = 1.07 RB/STB

The daily free fall drainage rate calculates 354.8 STBO per day. If we assume that rate is constant over the seventy-five and one-half year history of the area, it is estimated that a maximum of approximately 9,800,000 stock tank barrels could have drained into the area. This calculation does not account for oil draining out of the system and also assumes that the drainage over the life of the area is constant.

Oil pressure and fluid level maps have been used to determine the decrease in flow potential (φ) with time. The calculated daily oil flow rates

are 250.3 and 176.9 stock tank barrels per day in 1936 and 1946 respectively and are shown on Figure 28 along with the free fall drainage rate. These data have been used to estimate the expected inflow due to gravity drainage of 5,400,000 stock tank barrels. Again, oil flow out of the area was assumed negligible.

The original oil in place, the cumulative oil production and the maximum and expected oil drainage volumes have been used to estimate the oil saturation as of July 1, 1976. Without a contribution for gravity drainage, the minimum oil saturation is estimated at 16 percent. With the expected amount of oil inflow into the pilot area, the expected oil saturation is estimated at 31 percent. If the free fall drainage rate is assumed effective over life, the maximum oil saturation is estimated at 43 percent. A plot of the initial oil saturation versus estimated current oil saturation for the three cases is shown on Figure 29. For various assumed initial oil saturation, estimates of current saturation can be made. The petrophysical oil saturation of 39 percent lies approximately midway between the expected and maximum values of the volumetric oil saturation including the effects of gravity drainage.

Core Data

Five wells (256A-27, 12-7-27, 16-7-27, 285A-27, and 3-11-26) in and around the pilot area have been cored, and the cores analyzed under unstressed conditions. The location of these wells are shown on Figure 30 and represent the Immediate Pilot Area (updip to downdip). Four of the five wells were cored and analyzed in the late 1960's with the remaining well, 16-6-27, cored and analyzed as part of the current project.

The saturation and porosity measurements performed on samples from the cores were at unstressed conditions. It is known that unstressed samples will yield lower oil saturations and higher porosity values. Therefore, the data as reported cannot be used. However, in each of the cored wells, porosity logs were run from which an insitu porosity was determined. Koerperich⁽⁴⁾ reported an equation which can be used to correct unstressed oil saturations to stressed conditions given the insitu and laboratory porosity. However, the correction does not account for the flushing which might have occurred during the coring operations.

To estimate flushing, radioactive tritium was used in the mud while coring Well 256A-27. Measurements were made to determine amount of tritium found at the center of the core. Flushing was found to randomly range from 3-90 percent, and a uniform correction for flushing was not possible. From the tritium tracer used, it was evident that flushing did occur during the coring operations and the corrected oil saturations may represent minimum values of waterflood residual oil saturation.

Since these cored wells represent the pilot area, we have included all wells into the core analyses summary. The data have been analyzed by well and by sand using the unstressed core analyses and the log determined porosity to correct the unstressed oil saturation to insitu conditions.

The data analyzed by well are shown on Figure 31. The wells have been located in their approximate structural position. Shown are the corrected mean oil saturation values and the 95% confidence limits of the mean. Also shown are the unstressed core data by well. It is apparent that downdip in the pilot area there is an increase in the corrected oil saturation. In the

updip area there is approximately 10 saturation percent difference in unstressed versus corrected oil saturation but in well 3-11-26, the most downdip well, there is approximately 22 saturation percent difference in unstressed versus corrected oil saturation. This indicates that the porosity correction was greater for the downdip wells.

Although some selected core samples from the updip wells suggest corrected oil saturations approaching that of the assumed residual oil saturation for gravity drainage (13 percent), the majority of the samples indicate a substantially higher oil saturation. This could imply that the overall residual oil saturation for gravity drainage may be higher than assumed.

Due to the limited number of samples from each well, the analyses of the data by sands have included all samples from all wells. The unstressed and corrected oil saturation data are shown on Figure 32. As shown, the oil saturation by sand does vary with the highest oil saturation (corrected) occurring in the X and G_d sands. The remainder of the sands differ but range from the mid 20's to the low 30's in oil saturation.

The overall average corrected oil saturation of the 227 samples analyzed is 31.8 percent. The overall average log porosity is 23.9 percent which closely approximates the average porosity determined for the pilot area of 24.3 percent.

Waterflood Residual Oil Saturation

The waterflood residual oil saturation has been approximated by three types of tests. Thirty-five samples have been analyzed under stressed conditions for endpoint permeabilities and saturations. The average initial oil saturation and waterflood residual oil saturations from these data are approximately 65 and 24 percent respectively. Eight additional samples of

core material from Well 16-6-27 were evaluated using the countercurrent imbibition technique and resulted in an average waterflood residual oil saturation of 25 percent if the initial oil saturation of 65 percent was assumed. Two attempts were made to determine the insitu waterflood residual oil saturation using the log-inject-log technique outlined in the First Annual Report⁽¹⁾. Only one of these tests was considered successful and the waterflood residual oil saturation (Hw and Hx sands) was calculated to be 28 $\pm$ 4 percent.

The estimated range of the waterflood residual oil saturation can be bracketed by the data calculated from the log-inject-log tests as 28 $\pm$ 4 saturation percent. The associated error reflects our uncertainty of all the data including the corrected oil saturation determined from the cores in the area.

Reservoir Parameters and Volumes

The current oil saturation (as of July 1, 1976) is significantly lower than previously thought. Using the petrophysical oil saturation, a summary of the original and revised project parameters are shown on Table 14. There are considerable differences in the estimated reservoir parameters at the start of the waterflood portion of the test. The project volumes are summarized on Table 15, and, as shown, the estimated moveable oil in the pilot area is significantly lower.

CORE TESTS

In 1978, three full curve relative permeability experiments were attempted on core material from Well 16-6-27. Frozen core plugs were stressed to 900 psig and allowed to thaw. After thawing, the plugs were cleaned by flowing chloroform-methanol through the samples. The water permeability, at 100 percent water saturation, was measured with deionized water containing sodium chloride to approximate a formation water salinity of 6000 ppm. An oil flood was conducted using a mixture of 40 percent Soltrol and 60 percent Nujol. The oil viscosity was approximately 15.2 centipoise. After irreducible water saturation was reached, the oil permeability was determined and a waterflood was conducted using the previously mentioned water to a waterflood residual oil saturation.

The full curve relative permeability curves were determined using the Welge technique and indicated a decreasing water permeability with increasing water saturations. During the experiments, produced fines were noted in the effluent and it is speculated that the cores were being plugged during the waterflood. At the end of the experiments, the ratio of the water permeability at residual oil saturation to the oil permeability at irreducible water saturation were extremely low and ranged from 0.014 to 0.025 (Table 16). These data are extremely low when compared to the previous data (.30 to .35) obtained from Zone II core material and are due, in part, to the movement of the fines in the core and subsequent plugging.

In researching the previous data, original water relative permeability data (from 0.30 to 0.35 depending on how the data are averaged) were run using

water with salinities ranging from 100,000 to 140,000 ppm. This salinity range is significantly higher than any of the produced water salinities from the field.

The impact of these recent data is that the displacement mobility ratio of water displacing oil may not be as unfavorable as previously calculated.⁽¹⁾ In addition, the literature⁽⁵⁾ suggests that the divalent/monovalent ratio is important in the clay swelling process. This would affect the interpretation of the previous salinity reduction experiments⁽³⁾, which were also conducted using deionized water containing sodium chloride.

Additional core tests have been completed to determine (1) the effect of the divalent/monovalent ratio on permeability reduction due to clay swelling as the salinity is reduced, (2) full relative permeability curves with Coalinga crude and synthetic formation water, and (3) the effect of the oil wetting (Darley) treatment on water permeability.

Permeability Reduction Versus Salinity

Three new salinity versus permeability tests have been completed. These tests differ from previous tests,⁽³⁾ in that, in addition to using a synthetic brine of known salinity, the ratio of calcium (Ca^{++}) to sodium (Na^{+}) in the formation water and USBR injection water has been matched. The $\text{Ca}^{++}/\text{Na}^{+}$ ratio of formation water is approximately 0.02 by weight, and the USBR ratio equals approximately 0.15.

Sample A: A frozen sample of the Gd sand from the 16-6-27 core was stressed to 900 psi allowed to thaw, and then flushed with chloroform-methanol. A 35,000 ppm total salinity synthetic brine with a $\text{Ca}^{++}/\text{Na}^{+}$ weight ratio of 0.02 (approximating that of formation water) was injected into the core and the

permeability measured. The salinity was then gradually reduced in steps down to 280 ppm while maintaining a constant $\text{Ca}^{++}/\text{Na}^{+}$ ratio of 0.02. The water permeability determined at the various salinities is shown on Figure 33. Permeability reduction begins at approximately 2000 ppm and at the approximate salinity of USBR water is approximately 33 percent of the original permeability. Previous tests indicated that the reduction in permeability would start at approximately 3000 ppm and that the final permeability (at approximately 300 ppm) would be only 2 to 5 percent of the original permeability. It appears that the $\text{Ca}^{++}/\text{Na}^{+}$ ratio did decrease the sensitivity of the clays to fresh water. Also note the additional decrease in permeability at 280 ppm after the experiment was resumed after being shut-in for 16 hours. This shows that under static conditions, the longer the clays are in contact with fresh water, additional permeability reduction occurs due to clay swelling.

Sample B: This sample was from the Hx sand and was stressed and cleaned as was Sample A. The same salinity values and techniques were used for this sample except for the $\text{Ca}^{++}/\text{Na}^{+}$ ratio. In this experiment, the $\text{Ca}^{++}/\text{Na}^{+}$ ratio used was 0.15, which approximates that of the USBR injection water. Figure 34 shows the results of the experiment. Unlike Sample A, no permeability reduction was observed when the salinity was reduced from 35,000 ppm to 280 ppm. The $\text{Ca}^{++}/\text{Na}^{+}$ ratio of 0.15 appears to prevent any permeability reduction due to clay swelling and supports results reported in the literature⁽⁵⁾.

Sample C: A sample from the Hw sand was stressed and cleaned as before. The permeability was measured using synthetic Coalinga formation water having a total salinity of 7700 ppm and a $\text{Ca}^{++}/\text{Na}^{+}$ ratio of 0.018. The salinity was gradually reduced from that of synthetic formation water to synthetic USBR

water having a total salinity of about 700 ppm and a $\text{Ca}^{++}/\text{Na}^{+}$ ratio of 0.16. As can be seen on Figure 35, it appears that approximately 28 percent of the original permeability was lost. This gradual mixing of formation water to injection water was used to simulate, as closely as possible, the mixing which might occur in the reservoir.

Relative Permeability Curves

In view of low end point data obtained in 1978 and apparent plugging of the samples, three additional relative permeability curve experiments were conducted. The samples were prepared identically to those used for the permeability reduction versus salinity experiments. For the water permeability at 100 percent water saturation, synthetic formation water ($\text{Ca}^{++}/\text{Na}^{+} = .018$) was used. An oil flood was then conducted using Coalinga crude until irreducible water saturation was reached and the oil permeability measured. A waterflood was conducted using synthetic formation water to waterflood residual oil saturation. Throughout the experiment data was obtained to determine the relative permeability curves using the Welge technique.

After the waterflood, an additional waterflood was conducted using synthetic USBR water ($\text{Ca}^{++}/\text{Na}^{+} = .16$). In two of the three experiments, after the core had been flooded with synthetic USBR water, an oil flood was conducted to irreducible water saturation, again using Coalinga crude. The oil permeability was then measured.

The endpoint permeability data and saturations obtained from these experiments are summarized on Table 17. In two of these experiments, an emulsion was produced and use of the Welge technique to determine the full relative permeability curves was not possible. The relative permeability

curve obtained is shown on Figure 36. From these data, a low water relative permeability (water permeability at waterflood residual oil saturation to the initial oil permeability at irreducible water saturation) has been observed. These water relative permeability data are substantially lower than the data originally used for the Project and substantially reduce the calculated mobility ratio for a waterflood⁽¹⁾.

Darley Treatment Endpoint Permeability

To determine the effect of the Darley treatment on the water relative permeability, two experiments were run as part of our recent core testing program. Darley treatment was used as a completion fluid in all of the injection wells, all of the observation wells, and all but two of the main producers in the pilot area. The purpose in Darley treating the wells was to make the clays oil-wet in the vicinity of the wellbore to prevent the severe damage due to clay swelling thought to occur when USBR water was injected or produced. However, the results of our recent experiments in the laboratory have demonstrated that the permeability reduction is not severe when an adequate divalent/monovalent ratio is present.

These tests were conducted to determine the effect of Darley treatment on relative permeability data with divalent and monovalent ions present. Samples of the core material from Well 16-6-27 were used for these tests. After stressing and cleaning the samples, brine permeability (synthetic formation water having $\text{Ca}^{++}/\text{Na}^{+} = .018$) at 100 percent water saturation was measured. An oil flood was conducted using Coalinga crude to irreducible water saturation and the oil permeability measured. After irreducible water saturation was reached, a waterflood was conducted using 35,000 ppm brine having a $\text{Ca}^{++}/\text{Na}^{+}$

ratio of 0.02 to waterflood residual oil saturation to simulate the Darley preflush. The water permeability at residual oil saturation was measured. For comparison purposes, one of the samples (1086.7 ft) was Darley treated and the other (1970.0 ft) was not. The endpoint permeabilities of these samples are shown on Table 18. A flood was conducted in both samples gradually reducing the salinity from 40,000 ppm to 260 ppm while maintaining a constant calcium to sodium ratio of 0.15 (i.e., USBR water). The brine permeabilities at the salinity steps are shown on Table 19. Although the brine permeabilities are similar, the Darley treated sample (1986.7 ft) indicates a substantial increase in the brine permeability following the Darley treatment. It appears that the Darley treatment has protected or stabilized the clays by altering the wettability. This has resulted in an increase in the aqueous phase permeability. The low waterflood residual oil saturation in both samples after the salinity reduction phase is anomalous.

SHEAR SENSITIVITY OF KELZAN SOLUTIONS

Recent studies conducted in the laboratory and in the field have demonstrated that dilute Kelzan solutions (approximately 300 ppm) prepared from enzyme-treated concentrates (6,000 ppm) decrease in viscosity when subjected to shear rates (Newtonian) greater than approximately $0.9 \times 10^6 \text{ sec}^{-1}$.

Laboratory Shear Studies

Laboratory studies were conducted on diluted solutions prepared from both sheared and unsheared (6000 ppm) enzyme-treated Kelzan solutions. Dilutions (1:20), made from unsheared concentrate, were sheared by passing them through a shear-plate device (0.015 inch orifice) at various differential pressures. The results of these experiments are shown on Table 20. As the shear rate exceeds approximately $0.9 \times 10^6 \text{ sec}^{-1}$ (differential pressure exceeding 300 psi), significant decreases in viscosity are observed.

As a further test to determine if low shear rates would produce viscosity losses with multiple shearing, the 1:20 dilutions of the unsheared concentrate were passed repeatedly the shear plate device at 100 psi. The results of these experiments are shown on Table 21. As can be seen, the 1:20 dilutions of the unsheared Kelzan concentrate solution show a significant decrease in viscosity after multiple passes through the shear plate device at the same shear rate. This shear rate had no apparent effect on the initial viscosity.

The original 6,000 ppm enzyme-treated Kelzan concentrate was then subjected to shearing at 500 psi. Dilutions (1:20) made from the once-sheared concentrate were subjected to the same range of shear rates as those made from

the unsheared concentrate. The effects of multiple shearing on viscosity losses were similar whether or not the concentrates were sheared or unsheared. However, the susceptibility of 1:20 dilutions from a once-sheared concentrate to viscosity loss by multiple shearing at a constant shear rate appeared to be less than that for dilutions prepared from unsheared concentrate. A "limiting viscosity loss" seemed to be reached at a lower number of shears on those solutions prepared from sheared concentrate as shown on Table 22.

Field Shear Studies

To determine the effect, if any, of the shear exerted on Kelzan injection fluid by valves and sampling systems in the field, a temporary pressure-regulating and sampling apparatus was built in the field at Coalinga. The apparatus shown in Figure 37, consisted of adjustable bean valves in series so that the differential pressure between the pump discharge and the final effluent could be lowered in increments. A number of tests were conducted using seven bean valves in series in such a manner that the pressure differential across each valve was approximately 100 psi lower than that of the preceding valve. Samples were collected without a sampling bomb and with the bomb apparatus shown in detail in Figure 38. The viscosities of these samples were measured and the results are shown on Table 23.

All samples collected with the sampling bomb were collected in accordance with the sampling procedures summarized on Table 24. It can be seen from Run 1 data that at a differential pressure of 600 psi, sampling without the sample bomb results in a loss of 36 percent of the injection fluid viscosity. Even with the use of the sample bomb, the passage of the Kelzan injection fluid through the seven bean valves results in a 14 percent reduction in solution viscosity.

In an additional test, Kelzan injection fluid was pumped through all seven bean valves with each valve wide open. The differential pressure from the inlet to valve 1 to the effluent from valve 7 was 600 psi. The effluent sample obtained from the final valve, using the sampling bomb, had the same viscosity as that sampled without a bomb from the initial pump suction, indicating no loss in viscosity.

To determine the effect on injection fluid viscosity due to the differential pressure between the injection pump discharge and the wellhead, samples were obtained using the sampling bomb and viscosity measurements made. The results are shown on Table 25. Even using the sampling bomb, viscosity losses ranged from 5.9 percent at a differential pressure of 80 psi at Well 15-6-27 to 32.3 percent at a differential pressure of 540 psi at Well 2-9-26.

To minimize viscosity losses due to sampling, staging the pressure down at 100 psi increments may help. It also appears that the shear to which the Kelzan solution is subjected to when sampled downhole in the injection well is sufficient to cause losses in solution viscosity. Viscosity measurements from samples obtained with a bottomhole sampler from injection wells revealed the data summarized on Table 26. The sampler used was a stainless steel cylinder with a sealing valve on the bottom. After lowering the sampler to the desired depth, a pre-set clock would open the valve. The differential pressure would then fill the sample chamber and close when the pressure equalized. It is apparent from the data that the pressure differential has caused the polymer solution to shear and degrade. The use of a bottomhole sampler will not, therefore, provide samples which reveal the "true" viscosity of the bottomhole injection fluid, and care must be taken not to interpret bottomhole

sampler results as indicative of polymer solution degradation. A modified bottomhole sampler (Figure 39) has recently been used to eliminate this problem.

This low shear sampler has been constructed using standard oilfield bottomhole pump parts. A pump valve cage was placed on each end of an empty pump barrel. The top valve was used to reduce contamination of the sample while pulling the sampler out of the well. The sampler was moved up and down within the sample interval approximately ten times in an effort to obtain a representative sample. The fluid sample was removed through a threaded connection in the center of the top cage. The upper ball was positioned at the top of the cage before completely inserting this connection. This kept the ball off the seat and thus reduced shear forces during the sample removal. Fresh water (oxygen free) was placed in the sampler before running it into the well. The bottomhole sample viscosity measurements of 5.3 cp and 5.4 cp were approximately that of the wellhead value of 5.2 cp. This indicated that the water had been displaced and that the sample had not been degraded by shearing.

REFERENCES

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4. Koerperich, E. A., "Applications of Waxman-Smiths and Archie Equations for Determination of Oil Saturation in Shaly Sand Reservoirs", Journal of Petroleum Technology (October 1975).
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NOMENCLATURES

ϕ	porosity (Fractional Bulk Volume)
	ϕ_N , porosity from neutron log
	ϕ_D , porosity from density log
ρ	density (gm/cc)
	ρ_{ma} = rock matrix density
	ρ_b = bulk rock density
	ρ_f = fluid density
R_o	resistivity of water saturated rock (ohm-m)
R_t	formation resistivity (ohm-m)
R_w	formation water resistivity (ohm-m)
B	equivalent conductance of clay counter ions (1/equiv/ohm-m)
Q_v	quantity of cation exchangeable clay present (meg/ml of pore space)
m^*	cementation exponent for shaly sands
n^*	saturation exponent for shaly sands
F_a	apparent formation factor ($1/\phi^m$)
F^*	formation factor ($1/\phi^{m^*}$)
I	resistivity ratio
S	saturation (fraction of pore volume)
	S_o = oil saturation
	S_w = water saturation
	S_g = gas saturation
	S_{oi} = initial oil saturation
	S_{wc} or S_{wr} = initial or irreducible water saturation
	S_{orw} = residual oil saturation to waterflood
K	permeability (md)
	K_{oi} = initial oil permeability
	K_w = water permeability at S_{orw}
	K_b = water permeability at 100 percent water saturation
	K_o = oil permeability

NOMENCLATURES (Cont)

H	thickness (ft)
W	width (ft)
Φ	potential (psi)
μ	viscosity (centipoise)
	μ_o = oil viscosity
	μ_w = water viscosity
B_o	formation volume factor (RB/STB)
γ	specific gravity (dimensionless)
α	formation dip (degrees)
p	pressure (psig)
	P_{wf} = bottom hole flowing pressure
	P_{ihr} = pressure after one hour shut-in time
M	slope of P vs $T\Delta t+1$ plot (psi/cycle)
A	area (acres)
mls	milliliters
ppm	parts per million
ppb	parts per billion
cps	centipoise
μCi	microcurie
γ_N	Newtonian Shear Rate (sec^{-1})

Table 1**PRESSURE FALLOFF TESTS DURING WATER INJECTION
COALINGA POLYMER DEMONSTRATION PROJECT**

<u>WELL</u>	<u>DATE</u>	<u>RATE</u> (BPD)	<u>Pwf</u> (PSIG)	<u>P1hr</u> (PSIG)	<u>M</u> (PSI/CYCLE)	<u>KH/μ</u> (MD-FT/CP)	<u>KH (1)</u> (MD-FT)
2-7-26	11-5-76	1350	860	685	162	1355	867
	1-18-77	1350	939	760	185	1187	760
	3-26-77	1350	949	835	230	954	611
	6-28-77	1350	1088	830	230	954	611
	3-20-78	675	1088	655	110	998	639
2-9-26	11-5-76	1350	928	1195	195	720	461
	3-26-77	1350	1013	1325	360	610	390
	6-28-77	1350	1088	1240	352	624	399
	3-20-78	675	938	940	230	557	356
15-6-27	10-26-76	1350	769	440	160	1372	878
	1-18-77	1350	886	504	150	1463	936
	3-26-77	1350	907	650	170	1291	826
	6-28-77	1350	1024	485	94	2335	1494
	3-20-78	675	1034	535	75	1463	936
15-9-27	10-26-76	1350	527	287	95	2311	1479
	3-26-77	1350	769	437	108	2033	1301
	6-28-77	1350	875	418	86	2552	1633
	3-20-78	675	1022	497	95	1155	739

(1) $\mu_w = 0.64$

Table 2
CUMULATIVE WATER INJECTION BY SANDS
6/76 THRU 4/78
MBBLS

<u>SAND INTERVAL</u>	<u>WELL 2-7-26</u>	<u>WELL 2-9-26</u>	<u>WELL 15-6-27</u>	<u>WELL 15-9-27</u>	<u>TOTAL</u>	<u>INJECTION AS A PERCENTAGE OF MOVEABLE PORE VOLUME (1)</u>
E,F	165	183	167	226	741	52.0
Gc	41	123	82	150	396	41.7
Gd	7	49	84	98	238	38.7
X, Y, Hw	469 ⁽²⁾	209 ⁽²⁾	123	305	1106	79.0
Hx	134	213	308	42	697	179.3
Js, Jv	—	53	54	—	107	12.5
TOTAL	816	830	818	821	3285	58.3

(1) MOVEABLE PORE VOLUME = $7758 A \phi H (1 - S_{wc} - S_{orw})$
 (RESERVOIR VOLUME, POROSITY AND WATER SATURATION
 USED FOR INDIVIDUAL SANDS. RESIDUAL OIL SATURATION
 ASSUMED TO BE 28 PERCENT.)

(2) THIEF SANDS IN X AND Y

6/25/79--16 LR

Table 3
CUMULATIVE POLYMER INJECTION BY SANDS
5/78 THRU 3/79
MBBLS

<u>SAND INTERVAL</u>	<u>WELL 2-7-26</u>	<u>WELL 2-9-26</u>	<u>WELL 15-6-27</u>	<u>WELL 15-9-27</u>	<u>TOTAL</u>	<u>INJECTION AS A PERCENTAGE OF MOVEABLE PORE VOLUME⁽¹⁾</u>
E,F	8	53	13	16	90	2.9
Gc	2	20	6	7	35	2.5
Gd	3	17	9	11	40	3.7
X, Y, Hw	41 ⁽²⁾	49 ⁽²⁾	12	20	122	4.6
Hx	7	6	22	1	36	3.4
Js, Jv	—	—	4	—	4	0.3
TOTAL	61	145	66	55	327	3.0

(1) MOVEABLE PORE VOLUME = 7758 AØ H (1-Sorw)
 RESERVOIR VOLUME AND POROSITY USED FOR
 INDIVIDUAL SANDS. RESIDUAL OIL SATURATION
 ASSUMED TO BE 28 PERCENT.)

(2) THIEF SANDS IN X AND Y

6/25/79-17 LR

Table 4
QUALITY CONTROL OF POLYMER SOLUTION

<u>ANALYSIS</u>	<u>SPECIFICATION</u>	<u>TYPICAL VALUE</u>
OXYGEN	100 ppb MAXIMUM	< 10 ppb
BIOCIDE	30 ppm MINIMUM	50 $\pm$ 20 ppm
TOTAL IRON	0.5 ppm MAXIMUM	0.07 $\pm$ 0.03 ppm
VISCOSITY (1)	5.6 $\pm$ 0.6 cps	5.6 $\pm$ 0.4 cps
FILTERABILITY (2)	2500 mls MINIMUM	4000 $\pm$ 1000 mls
POLYMER CONCENTRATION	AS REQUIRED FOR VISCOSITY	370 $\pm$ 20 ppm

(1) VISCOSITY @ 7.3 SEC ⁻¹ AND 100° F

(2) FILTRATE VOLUME PASSED THROUGH A 1.2
MICRON MILLIPORE MEMBRANE IN FIVE MINUTES AT A
DIFFERENTIAL PRESSURE OF 20 PSIG

6/25/79-19 LR

TABLE 5
RADIOACTIVE TRACER RESPONSE
COALINGA POLYMER DEMONSTRATION PROJECT

I.D.	WELL #	SAMPLE DATE 1	SAMPLE DATE 2	ANALYSIS DATE	COBALT-60 μCi/BBL	IODINE-125 μCi/BBL	SULFUR-35 μCi/BBL	TRITIUM μCi/BBL

345	1-5	05/01/78		03/02/79	0.0	0.0	N/A	N/A
1	1-5	05/24/78	05/30/78	11/10/78	0.003800	0.0	0.308000	0.0
2	1-5	05/26/78		06/21/78	N/A	N/A	0.364000	0.0
3	1-5	06/06/78	06/09/78	11/10/78	0.003700	0.0	0.0	0.0
4	1-5	06/18/78		11/10/78	0.006900	0.0	0.0	0.0
5	1-5	06/25/78		11/10/78	0.004900	0.0	0.0	0.0
6	1-5	07/24/78	07/28/78	11/10/78	0.005300	0.0	0.0	0.0
7	1-5	09/04/78	09/14/78	11/10/78	0.004500	0.0	0.0	0.0
8	1-5	10/10/78	10/19/78	11/10/78	0.003900	0.0	N/A	N/A
9	1-5	11/29/78	12/08/78	02/02/79	0.008800	0.0	N/A	N/A
346	1-5	01/25/79		03/02/79	0.0	0.0	N/A	N/A
348	1-8	05/04/78		03/02/79	0.0	0.0	N/A	N/A
10	1-8	05/22/78	05/30/78	11/10/78	0.014000	0.0	0.0	0.0
349	1-8	05/24/78		11/20/78	N/A	N/A	0.561000	0.0
344	1-8	05/30/78		11/20/78	N/A	N/A	0.340000	0.0
11	1-8	06/01/78		11/10/78	0.014400	0.0	0.0	0.0
12	1-8	06/09/78		11/10/78	0.0	0.0	0.0	0.0
13	1-8	06/16/78		11/10/78	0.0	0.0	0.0	0.0
14	1-8	06/23/78		11/10/78	0.0	0.0	0.0	0.0
15	1-8	07/05/78		11/10/78	0.0	0.0	0.0	0.0
16	1-8	07/09/78		11/10/78	0.0	0.0	0.0	0.0
17	1-8	07/12/78		11/10/78	0.0	0.0	0.0	0.0
18	1-8	08/27/78	09/03/78	11/10/78	0.0	7.310000	0.0	0.0
19	1-8	09/29/78	10/04/78	11/10/78	0.0	5.930000	0.0	1.100000
21	1-8	10/04/78		11/10/78	N/A	N/A	0.0	1.100000
341	1-8	10/13/78		11/20/78	N/A	N/A	0.0	0.700000
342	1-8	10/20/78		11/20/78	N/A	N/A	0.0	0.900000
20	1-8	11/15/78	10/20/78	02/02/79	0.060600	5.640000	N/A	N/A
374	1-8	01/19/79		03/02/79	0.0	0.044625	N/A	N/A
22	1-9	06/02/78		11/10/78	0.0	0.0	0.0	0.0
23	1-9	06/05/78		11/10/78	0.0	0.0	0.0	0.0
24	1-9	06/13/78		11/10/78	0.0	0.0	0.0	0.0
25	1-9	06/18/78		11/10/78	0.0	0.0	0.0	0.0
26	1-9	06/20/78		11/10/78	0.0	0.0	0.0	0.0
27	1-9	06/23/78		11/10/78	0.005400	0.0	0.0	0.0
28	1-9	06/27/78		11/10/78	0.0	0.0	0.0	0.0
29	1-9	07/02/78		11/10/78	0.004700	0.0	0.0	0.0
30	1-9	07/22/78		11/10/78	0.0	0.0	0.0	0.0
31	1-9	08/16/78		11/10/78	0.0	0.0	0.0	0.0
32	1-9	08/26/78		11/10/78	0.0	0.0	0.0	0.700000
37	1-9	09/06/78		10/27/78	N/A	N/A	0.0	0.600000
33	1-9	09/22/78	09/27/78	11/10/78	0.0	5.620000	0.0	0.0
34	1-9	09/27/78		10/27/78	N/A	N/A	0.0	1.400000

TABLE 5 (CONTINUED)
RADIOACTIVE TRACER RESPONSE
COALINGA POLYMER DEMONSTRATION PROJECT

I.D.	WELL #	SAMPLE DATE 1	SAMPLE DATE 2	ANALYSIS DATE	COBALT-60 μCi/BBL	IODINE-125 μCi/BBL	SULFUR-35 μCi/BBL	TRITIUM μCi/BBL

38	1-9	10/02/78		10/28/78	N/A	N/A	0.0	1.700000
39	1-9	10/07/78		10/27/78	N/A	N/A	0.0	1.700000
40	1-9	10/12/78		10/27/78	N/A	N/A	0.0	1.500000
41	1-9	10/17/78		10/27/78	N/A	N/A	0.0	1.500000
34	1-9	10/20/78		11/10/78	0.0	0.0	0.0	1.500000
35	1-9	11/13/78	11/20/78	02/02/79	0.0	14.048000	0.0	0.005000
78	4-6	05/24/78	05/26/78	11/10/78	0.0	0.0	0.0	0.0
79	4-6	05/30/78	06/01/78	11/10/78	0.0	0.0	0.0	0.0
80	4-6	06/11/78		11/10/78	0.0	0.0	0.0	0.0
81	4-6	06/18/78		11/10/78	0.011200	0.0	0.0	0.0
82	4-6	06/26/78		11/10/78	0.0	0.0	0.0	0.0
83	4-6	07/08/78		11/10/78	0.007300	0.0	0.0	0.0
84	4-6	07/15/78		11/10/78	0.0	0.0	0.0	0.0
85	4-6	07/25/78		11/10/78	0.0	0.0	0.0	0.0
86	4-6	08/13/78		11/10/78	0.0	0.0	0.0	0.0
87	4-6	10/08/78	10/17/78	11/10/78	0.0	0.0	0.0	0.0
88	4-6	11/22/78	12/05/78	02/02/79	0.0	0.0	0.0	N/A
388	4-6	01/19/79	01/26/79	03/02/79	0.0	0.0	N/A	N/A
42	1-14	06/16/78		11/10/78	0.005300	0.0	0.0	0.0
43	1-14	07/14/78	08/16/78	11/10/78	0.0	0.0	0.0	0.0
44	1-26	06/22/78		11/10/78	0.004200	0.0	0.0	0.0
45	1-26	07/01/78		11/10/78	0.0	0.0	0.0	0.0
46	1-26	07/12/78		11/10/78	0.005800	0.0	0.0	0.0
47	1-26	11/14/78	10/16/78	02/02/79	0.0	0.0	N/A	N/A
389	1-26	01/08/79	01/26/79	03/02/79	0.0	0.0	N/A	N/A
201	107X	06/22/78		11/10/78	0.0	0.0	0.0	0.0
202	107X	07/07/78		11/10/78	0.014000	0.0	0.0	0.0
203	107X	10/26/78	11/15/78	02/02/79	0.0	0.0	N/A	N/A
100	14-7	05/14/78		11/10/78	0.007000	0.0	0.0	0.0
101	14-7	05/20/78	07/11/78	11/10/78	0.004500	0.0	0.0	0.0
102	14-7	06/20/78		11/10/78	0.005500	0.0	0.0	0.0
103	14-7	07/15/78		11/10/78	0.012400	0.0	0.0	0.0
104	14-7	07/25/78		11/10/78	0.011600	0.0	0.0	0.0
105	14-7	09/27/78	10/04/78	11/10/78	0.015800	0.0	0.0	0.0
107	14-7	11/03/78	11/30/78	02/02/79	0.0	0.0	N/A	N/A
106	14-7	11/16/78		02/02/79	0.028900	0.0	N/A	N/A
386	14-7	01/17/79		03/02/79	0.019382	0.0	N/A	N/A
108	15-8	05/15/78		11/10/78	0.0	0.0	0.0	0.0
109	15-8	05/28/78		11/10/78	0.0	0.0	0.0	0.0
110	15-8	06/13/78		11/10/78	0.090200	0.0	0.0	0.0
111	15-8	06/18/78		11/10/78	0.0	0.0	0.0	0.0
112	15-8	06/24/78		11/10/78	0.0	0.0	0.0	0.0
113	15-8	06/29/78		11/10/78	0.0	0.0	0.0	0.0
114	15-8	07/02/78		11/10/78	0.012400	0.0	0.0	0.0
115	15-8	07/14/78		11/10/78	0.0	0.0	0.0	0.0

TABLE 5 (CONTINUED)
RADIOACTIVE TRACER RESPONSE
COALINGA POLYMER DEMONSTRATION PROJECT

I.D.	WELL #	SAMPLE DATE 1	SAMPLE DATE 2	ANALYSIS DATE	COBALT-60 μCi/BBL	IODINE-125 μCi/BBL	SULFUR-35 μCi/BBL	TRITIUM μCi/BBL

116	15-8	07/22/78		11/10/78	0.006100	0.0	0.0	0.0
117	15-8	07/27/78		11/10/78	0.0	0.0	0.0	0.0
118	15-8	08/02/78		11/10/78	0.0	0.0	0.0	0.0
119	15-8	08/17/78	08/26/78	11/10/78	0.0	0.0	0.0	0.0
120	15-8	09/24/78	10/06/78	11/10/78	0.0	0.0	0.0	0.0
121	15-8	10/20/78	11/01/78	11/10/78	0.0	0.0	0.0	0.0
122	15-8	12/04/78	12/11/78	02/02/79	0.0	0.0	N/A	N/A
375	15-8	01/15/79	01/24/79	03/02/79	0.0	0.0	N/A	N/A
124	16-7	05/14/78		11/10/78	0.0	0.0	0.0	0.0
125	16-7	05/19/78		11/10/78	0.0	0.0	0.0	0.0
126	16-7	05/24/78		11/10/78	0.0	0.0	0.0	0.0
127	16-7	05/26/78		11/10/78	0.016200	0.0	0.0	0.0
128	16-7	06/02/78		11/10/78	0.0	0.0	0.0	0.0
129	16-7	06/04/78		11/10/78	0.0	0.0	0.0	0.0
130	16-7	06/09/78		11/10/78	0.0	0.0	0.0	0.0
131	16-7	06/14/78		11/10/78	0.0	0.0	0.0	0.0
132	16-7	06/28/78		11/10/78	0.0	0.0	0.0	0.0
133	16-7	07/03/78		11/10/78	0.0	0.0	0.0	0.0
134	16-7	07/10/78		11/10/78	0.029200	0.0	0.0	0.0
135	16-7	08/08/78	08/25/78	11/10/78	0.0	0.0	0.0	0.500000
144	16-7	08/16/78		10/13/78	N/A	N/A	0.0	0.600000
139	16-7	08/25/78		10/12/78	N/A	N/A	0.0	0.600000
140	16-7	09/16/78		10/12/78	N/A	N/A	0.0	1.000000
141	16-7	09/24/78		10/12/78	N/A	N/A	0.0	1.000000
145	16-7	09/27/78		10/13/78	N/A	N/A	0.0	0.800000
142	16-7	10/01/78		10/13/78	N/A	N/A	0.0	0.600000
143	16-7	10/06/78		10/13/78	N/A	N/A	0.0	0.900000
136	16-7	10/06/78	10/11/78	11/10/78	0.0	0.0	0.0	0.900000
146	16-7	10/11/78		11/20/78	N/A	N/A	0.0	0.600000
147	16-7	10/16/78		11/20/78	N/A	N/A	0.0	0.600000
148	16-7	10/20/78		11/20/78	N/A	N/A	0.0	0.500000
149	16-7	10/30/78		11/20/78	N/A	N/A	0.0	0.400000
137	16-7	11/06/78	11/20/78	02/02/79	0.0	0.0	0.0	0.0
138	16-7	12/28/78	01/04/79	02/02/79	0.0	0.0	0.0	0.0
387	16-7	01/10/79	01/15/79	03/02/79	0.0	0.0	N/A	N/A
290	187X	06/20/78		11/10/78	0.0	0.0	0.0	0.0
392	187X	08/22/78		03/02/79	0.0	0.0	N/A	N/A
60	3-11	05/16/78		11/10/78	0.0	0.0	0.0	0.0
63	3-11	05/23/78	05/30/78	11/10/78	0.0	0.0	0.0	0.0
61	3-11	05/24/78		11/10/78	0.0	0.0	0.0	0.0
62	3-11	05/26/78		11/10/78	0.0	0.0	0.0	0.0
64	3-11	06/02/70		11/10/70	0.0	0.0	0.0	0.0
65	3-11	06/09/78		11/10/78	0.0	0.0	0.0	0.0
66	3-11	06/12/78		11/10/78	0.0	0.0	0.0	0.0
67	3-11	06/18/78		11/10/78	0.0	0.0	0.0	0.0
68	3-11	06/23/78		11/10/78	0.0	0.0	0.0	0.0
69	3-11	07/02/78		11/10/78	0.004700	0.0	0.0	0.0
70	3-11	07/11/78		11/10/78	0.009000	0.0	0.0	0.0

TABLE 5 (CONTINUED)
RADIOACTIVE TRACER RESPONSE
COALINGA POLYMER DEMONSTRATION PROJECT

I.D.	WELL #	SAMPLE DATE 1	SAMPLE DATE 2	ANALYSIS DATE	COBALT-60 μCi/BBL	IODINE-125 μCi/BBL	SULFUR-35 μCi/BBL	TRITIUM μCi/BBL

71	3-11	07/20/78		11/10/78	0.0	0.0	0.0	0.0
72	3-11	07/26/78		11/10/78	0.0	0.0	0.0	0.0
73	3-11	08/05/78		11/10/78	0.0	0.0	0.0	0.0
74	3-11	08/14/78		11/10/78	0.0	0.0	0.0	0.0
75	3-11	09/18/78	09/26/78	11/10/78	0.0	0.0	0.0	0.0
76	3-11	10/10/78	10/31/78	11/10/78	0.0	0.0	0.0	0.0
77	3-11	11/16/78	11/27/78	02/02/79	0.0	0.0	N/A	N/A
89	4-13	06/23/78		11/10/78	0.010500	0.0	0.0	0.0
90	4-13	07/04/78		11/10/78	0.0	0.0	0.0	0.0
91	4-13	08/18/78	09/14/78	11/10/78	0.0	0.0	0.0	0.0
92	4-13	11/09/78	11/25/78	02/02/79	0.0	0.0	N/A	N/A
93	6-10	06/16/78		11/10/78	0.0	0.0	0.0	0.0
94	6-10	06/23/78		11/10/78	0.0	0.0	0.0	0.0
95	6-10	07/04/78		11/10/78	0.009700	0.0	0.0	0.0
96	6-10	07/14/78		11/10/78	0.010500	0.0	0.0	0.0
97	6-10	10/12/78	11/02/78	11/10/78	0.0	0.0	0.0	0.0
98	6-10	12/18/78		02/02/79	0.0	0.0	N/A	N/A
359	685A	11/28/78		02/02/79	0.0	0.0	N/A	N/A
99	10-26	11/30/78	12/15/78	02/02/79	0.0	0.034600	N/A	N/A
150	34-27	05/24/78		11/10/78	0.0	0.0	0.0	0.0
151	34-27	05/26/78		11/10/78	0.006300	0.0	0.0	0.0
152	34-27	05/30/78		11/10/78	0.005100	0.0	0.0	0.0
153	34-27	06/02/78		11/10/78	0.014500	0.0	0.0	0.0
154	34-27	06/06/78		11/10/78	0.012700	0.0	0.0	0.0
155	34-27	06/10/78		11/10/78	0.009700	0.0	0.0	0.0
156	34-27	07/02/78		11/10/78	0.015600	0.0	0.0	0.0
157	34-27	07/13/78		11/10/78	0.012000	0.0	0.0	0.0
158	34-27	07/26/78		11/10/78	0.012300	0.0	0.0	0.0
159	34-27	08/23/78	09/06/78	11/10/78	0.013000	0.0	0.0	0.0
160	34-27	09/19/78	10/04/78	11/10/78	0.009100	0.0	0.0	0.0
161	34-27	12/18/78	12/29/78	02/02/79	0.0	0.0	0.0	0.0
385	34-27	01/05/79	01/31/79	03/02/79	0.010014	0.0	N/A	N/A
162	38-26	06/16/78		11/10/78	0.0	0.0	0.0	0.0
163	38-26	06/23/78		11/10/78	0.0	0.0	0.0	0.0
164	58-27	05/23/78	05/25/78	11/10/78	0.0	0.0	0.0	0.0
165	58-27	05/29/78	05/31/78	11/10/78	0.0	0.0	0.0	0.0
166	58-27	06/06/78	06/08/78	11/10/78	0.0	0.0	0.0	0.0
170	58-27	06/08/78		06/02/78	N/A	N/A	1.090000	0.0
167	58-27	06/11/78		11/10/78	0.006000	0.0	1.149000	0.0
171	58-27	06/12/78		06/02/78	N/A	N/A	0.438000	0.0
168	58-27	06/24/78		11/10/78	0.0	0.0	0.760000	0.0
169	58-27	07/03/78		11/10/78	0.008000	0.0	0.534000	0.0
172	58-27	10/17/78		02/02/78	0.0	0.0	N/A	N/A
371	58-27	01/09/79	01/22/79	03/02/79	0.0	0.0	N/A	N/A

TABLE 5 (CONTINUED)
RADIOACTIVE TRACER RESPONSE
COALINGA POLYMER DEMONSTRATION PROJECT

I.D.	WELL #	SAMPLE DATE 1	SAMPLE DATE 2	ANALYSIS DATE	COBALT-60 μCi/BBL	IODINE-125 μCi/BBL	SULFUR-35 μCi/BBL	TRITIUM μCi/BBL

173	59-27	07/07/78	07/27/78	11/10/78	0.0	0.0	0.0	0.0
174	59-27	09/07/78	10/03/78	11/10/78	0.0	0.0	0.0	0.0
175	59-27	11/14/78		02/02/79	0.0	0.0	0.0	0.0
176	71-27	06/19/78		11/10/78	0.0	0.0	0.0	0.0
177	71-27	07/31/78	08/21/78	11/10/78	0.0	0.0	0.0	0.0
178	71-27	10/23/78		02/02/79	0.0	0.0	0.0	0.0
394	71-27	01/11/79		03/02/79	0.0	0.0	N/A	N/A
179	92-27	05/19/78		11/10/78	0.0	0.0	0.0	0.0
180	92-27	05/24/78		11/10/78	0.0	0.0	0.0	0.0
181	92-27	05/30/78		11/10/78	0.0	0.0	0.0	0.0
182	92-27	06/01/78		11/10/78	0.0	0.0	0.0	0.0
183	92-27	06/06/78		11/10/78	0.0	0.0	0.0	0.0
184	92-27	06/10/78		11/10/78	0.0	0.0	0.0	0.0
185	92-27	06/12/78		11/10/78	0.0	0.0	0.0	0.0
186	92-27	06/25/78		11/10/78	0.0	0.0	0.0	0.0
187	92-27	07/04/78		11/10/78	0.0	0.0	0.0	0.0
188	92-27	07/23/78		11/10/78	0.010300	0.0	0.0	0.0
189	92-27	08/02/78		11/10/78	0.0	0.0	0.0	0.0
190	92-27	09/13/78	09/23/78	11/10/78	0.0	1.370000	0.0	0.0
191	92-27	11/20/78	12/13/78	02/02/79	0.0	5.250000	0.0	0.0
384	92-27	01/16/79	01/23/79	03/02/79	0.0	0.103378	N/A	N/A
192	94-27	06/06/78		11/10/78	0.0	0.0	0.0	0.0
193	94-27	06/16/78		11/10/78	0.014000	0.0	0.0	0.0
194	94-27	06/23/78		11/10/78	0.0	0.0	0.0	0.0
195	94-27	07/01/78		11/10/78	0.0	0.0	0.0	0.0
196	94-27	07/03/78		11/10/78	0.0	0.0	0.0	0.0
197	94-27	07/26/78		11/10/78	0.0	0.0	0.0	0.0
198	94-27	08/02/78		11/10/78	0.0	0.0	0.0	0.0
199	94-27	08/09/78	08/17/78	11/10/78	0.0	0.0	0.0	0.0
200	94-27	11/07/78	11/17/78	02/02/79	0.0	0.0	N/A	N/A
398	94-27	01/05/79		03/02/79	0.0	0.0	N/A	N/A
204	113-27	05/22/78	05/29/78	11/10/78	0.0	0.0	0.0	0.0
205	113-27	06/02/78		11/10/78	0.0	0.0	0.0	0.0
206	113-27	06/10/78		11/10/78	0.0	0.0	0.0	0.0
207	113-27	06/15/78		11/10/78	0.0	0.0	0.0	0.0
208	113-27	09/18/78	09/23/78	11/10/78	0.0	0.0	0.0	0.0
209	113-27	10/13/78	10/23/78	11/10/78	0.0	0.0	N/A	N/A
211	113-27	12/26/78		02/02/79	0.0	0.0	0.0	0.0
377	113-27	01/16/79		03/02/79	0.0	0.0	N/A	N/A
212	114-27	06/13/78		11/10/78	0.0	0.0	0.0	1.600000
213	114-27	06/30/78	07/06/78	11/10/78	0.0	0.0	0.0	0.0
214	114-27	09/20/78		11/10/78	0.0	0.0	0.0	1.500000
215	114-27	10/09/78	10/19/78	11/10/78	0.0	0.0	0.0	1.000000
217	114-27	10/19/78		11/20/78	N/A	N/A	0.0	0.500000
360	114-27	11/02/78		11/20/78	N/A	N/A	0.0	1.300000

TABLE 5 (CONTINUED)
RADIOACTIVE TRACER RESPONSE
COALINGA POLYMER DEMONSTRATION PROJECT

I.D.	WELL #	SAMPLE DATE 1	SAMPLE DATE 2	ANALYSIS DATE	COBALT-60 μCi/BBL	IODINE-125 μCi/BBL	SULFUR-35 μCi/BBL	TRITIUM μCi/BBL

216	114-27	11/22/78	12/12/78	02/02/79	0.0	0.0	N/A	N/A
373	114-27	01/16/79	01/25/79	03/02/79	0.0	0.0	N/A	N/A
218	115-27	05/29/78		11/10/78	0.0	0.0	0.0	0.0
219	115-27	06/04/78		11/10/78	0.0	0.0	0.0	0.0
220	115-27	06/08/78		11/10/78	0.0	0.0	0.0	0.0
221	115-27	06/14/78		11/10/78	0.0	0.0	0.0	0.0
222	115-27	06/19/78		11/10/78	0.0	0.0	0.0	0.0
223	115-27	06/27/78		11/10/78	0.0	0.0	0.0	0.0
224	115-27	07/03/78		11/10/78	0.0	0.0	0.0	0.0
225	115-27	07/09/78	07/23/78	11/10/78	0.0	0.0	0.0	0.0
226	115-27	08/05/78	08/18/78	11/10/78	0.0	0.0	0.0	0.0
227	115-27	09/29/78	10/06/78	11/10/78	0.0	0.0	0.0	0.0
391	115-27	01/22/79		03/02/79	0.0	0.0	N/A	N/A
228	116-27	06/19/78		11/10/78	0.0	0.0	0.0	0.0
229	116-27	06/29/78		11/10/78	0.0	0.0	0.0	0.0
370	118-27	05/02/78		03/02/79	0.026768	0.0	N/A	N/A
230	118-27	05/19/78		11/10/78	0.0	0.0	0.0	0.0
231	118-27	06/02/78		11/10/78	0.017700	0.0	0.0	0.0
232	118-27	06/09/78		11/10/78	0.020400	0.0	0.0	0.0
233	118-27	06/13/78		11/10/78	0.019600	0.0	0.0	0.0
234	118-27	06/19/78		11/10/78	0.021300	0.0	0.0	0.0
235	118-27	07/02/78		11/10/78	0.021200	0.0	0.0	0.0
236	118-27	07/07/78		11/10/78	0.025400	0.0	0.0	0.0
237	118-27	07/14/78		11/10/78	0.020300	0.0	0.0	0.0
238	118-27	07/20/78		11/10/78	0.021700	0.0	0.0	0.0
239	118-27	07/26/78		11/10/78	0.021000	0.0	0.0	0.0
240	118-27	08/12/78	08/17/78	11/10/78	0.023600	0.0	0.0	0.0
241	118-27	08/27/78	09/04/78	11/10/78	0.020700	0.0	0.0	0.0
242	118-27	09/29/78	10/09/78	11/10/78	0.024800	0.0	0.0	0.0
383	118-27	01/16/79	01/23/79	03/02/79	0.028722	0.0	N/A	N/A
243	120-27	06/04/78		11/10/78	0.0	0.0	0.0	0.0
244	120-27	06/10/78		11/10/78	0.0	0.0	0.0	0.0
245	120-27	06/15/78		11/10/78	0.0	0.0	0.0	0.0
246	120-27	06/20/78		11/10/78	0.0	0.0	0.0	0.0
247	120-27	06/28/78		11/10/78	0.0	2.140000	0.0	0.0
248	120-27	07/04/78		11/10/78	0.0	0.0	0.0	0.0
249	120-27	09/16/78	09/26/78	11/10/78	0.0	0.0	0.0	0.0
250	120-27	10/13/78		02/02/79	0.0	0.0	N/A	N/A
251	120-27	11/08/78	12/08/78	02/02/79	0.0	0.0	N/A	N/A
369	120-27	01/23/79		03/02/79	0.0	0.0	N/A	N/A
252	121-27	05/18/78	05/22/78	11/10/78	0.0	0.0	0.0	0.0
253	121-27	05/25/78	05/29/78	11/10/78	0.0	0.0	0.0	0.0
254	121-27	06/06/78	06/11/78	11/10/78	0.0	0.0	0.0	0.0
255	121-27	06/08/78		11/10/78	0.0	0.0	0.0	0.0
256	121-27	07/01/78		11/10/78	0.0	0.0	0.0	0.0
257	121-27	07/13/78	07/19/78	11/10/78	0.0	0.0	N/A	N/A

TABLE 5 (CONTINUED)
RADIOACTIVE TRACER RESPONSE
COALINGA POLYMER DEMONSTRATION PROJECT

I.D.	WELL #	SAMPLE DATE 1	SAMPLE DATE 2	ANALYSIS DATE	COBALT-60 μCi/BBL	IODINE-125 μCi/BBL	SULFUR-35 μCi/BBL	TRITIUM μCi/BBL

258	121-27	09/24/78	10/10/78	11/10/78	0.0	0.0	N/A	N/A
259	121-27	11/28/78		02/02/79	0.0	0.0	N/A	N/A
397	121-27	01/30/79		03/02/79	0.0	0.0	N/A	N/A
260	127-26	06/14/78	07/12/78	11/10/78	0.0	0.0	0.0	0.0
261	127-26	09/15/78	11/02/78	11/10/78	0.0	0.0	0.0	0.0
262	137-26	06/06/78		11/10/78	0.008000	0.0	0.0	0.0
263	137-26	06/16/78		11/10/78	0.134000	0.0	0.0	0.0
264	137-26	07/14/78		11/10/78	0.072000	0.0	0.0	0.0
265	137-26	07/18/78		11/10/78	0.016000	0.0	0.0	0.0
266	137-26	11/07/78		02/02/79	0.0	0.0	N/A	N/A
267	145-27	06/16/78		11/10/78	0.0	0.0	0.0	0.0
268	152-27	06/02/78		11/10/78	0.0	0.0	0.0	0.0
269	152-27	06/13/78		11/10/78	0.0	0.0	0.0	0.0
270	152-27	08/03/78	08/13/78	11/10/78	0.0	0.0	0.0	0.0
271	152-27	09/27/78	10/08/78	11/10/78	0.0	0.0	0.0	0.0
272	152-27	12/07/78		02/02/79	0.0	0.0	N/A	N/A
390	152-27	02/01/79		03/02/79	0.0	0.0	N/A	N/A
372	165-27	05/02/78		03/02/79	0.011004	0.0	N/A	N/A
273	165-27	06/21/78		11/10/78	0.011000	0.0	0.0	0.0
274	165-27	07/01/78		11/10/78	0.017000	0.0	0.0	0.0
275	165-27	07/10/78		11/10/78	0.024000	0.0	0.0	0.0
276	165-27	07/25/78		11/10/78	0.016000	0.0	0.0	0.0
277	165-27	10/17/78		02/02/79	0.020000	0.0	N/A	N/A
376	165-27	01/08/79		03/02/79	0.007913	0.0	N/A	N/A
278	172-27	06/05/78		11/10/78	0.0	0.0	0.0	0.0
279	172-27	06/14/78		11/10/78	0.0	0.0	0.0	0.0
280	172-27	06/26/78		11/10/78	0.0	0.0	0.0	0.0
281	172-27	06/30/78		11/10/78	0.006900	0.0	0.0	0.0
282	172-27	07/05/78		11/10/78	0.0	0.0	0.0	0.0
283	172-27	10/20/78	11/12/78	02/02/79	0.0	0.0	0.0	0.0
284	176-27	06/10/78	06/15/78	11/10/78	0.0	0.0	0.0	0.0
285	176-27	06/19/78	06/25/78	11/10/78	0.0	0.0	0.0	0.0
286	176-27	07/16/78	07/23/78	11/10/78	0.0	0.0	0.0	0.0
287	176-27	08/25/78	09/27/78	11/10/78	0.0	0.0	0.0	0.0
288	176-27	10/13/78	10/17/78	02/02/79	0.0	0.0	N/A	N/A
289	176-27	10/27/78		02/02/79	0.0	0.0	N/A	N/A
395	176-27	01/15/79		03/02/79	0.0	0.0	N/A	N/A
304	225-27	06/18/78		11/10/78	0.0	0.0	0.0	0.0
322	227-27	08/03/78	08/08/78	11/10/78	0.0	0.0	0.0	0.0
291	265-27	06/18/78		11/10/78	0.224800	0.0	0.0	0.0

TABLE 5 (CONTINUED)
RADIOACTIVE TRACER RESPONSE
COALINGA POLYMER DEMONSTRATION PROJECT

I.D.	WELL #	SAMPLE DATE 1	SAMPLE DATE 2	ANALYSIS DATE	COBALT-60 μCi/BBL	IODINE-125 μCi/BBL	SULFUR-35 μCi/BBL	TRITIUM μCi/BBL

292	273-27	06/02/78	06/04/78	11/10/78	0.0	0.0	0.0	0.0
293	273-27	06/14/78		11/10/78	0.013200	0.0	0.0	0.0
294	273-27	06/18/78		11/10/78	0.0	0.0	0.0	0.0
297	273-27	07/03/78		11/10/78	0.0	0.0	0.0	0.0
295	273-27	07/20/78		11/10/78	0.0	0.0	0.0	0.0
296	273-27	07/28/78		11/10/78	0.0	0.0	0.0	0.0
298	273-27	08/25/78	09/04/78	11/10/78	0.006900	0.0	0.0	0.0
299	273-27	09/27/78	10/04/78	11/10/78	0.008800	0.0	0.0	0.0
379	273-27	01/26/79		03/02/79	0.012864	0.0	N/A	N/A
300	275-27	05/23/78		11/10/78	0.0	0.0	0.0	0.0
301	275-27	05/29/78	05/31/78	11/10/78	0.0	0.0	0.0	0.0
302	275-27	06/04/78	06/08/78	11/10/78	0.0	0.0	0.0	0.0
303	275-27	06/12/78		11/10/78	0.025900	0.0	0.0	0.0
305	275-27	06/29/78		11/10/78	0.0	0.0	0.0	0.0
306	275-27	07/06/78		11/10/78	0.0	0.0	0.0	0.0
307	275-27	08/13/78	09/26/78	11/10/78	0.0	0.0	0.0	0.0
308	275-27	10/23/78	11/21/78	02/02/79	0.0	0.0	N/A	N/A
309	275-27	11/14/78		02/02/79	0.018800	0.0	N/A	N/A
382	275-27	01/17/79		03/02/79	0.0	0.0	N/A	N/A
310	276-27	06/02/78	06/21/78	11/10/78	0.0	0.0	0.0	0.0
311	276-27	06/06/78		11/10/78	0.005100	0.0	0.0	0.0
312	276-27	06/18/78		11/10/78	0.135900	0.0	0.0	0.0
313	276-27	06/26/78		11/10/78	0.0	0.0	1.070000	0.0
314	276-27	07/01/78		11/10/78	0.0	0.0	0.480000	0.0
315	276-27	08/16/78	08/26/78	11/10/78	0.0	0.0	0.0	0.0
316	276-27	09/28/78	10/08/78	11/10/78	0.0	0.021000	0.0	0.0
317	276-27	11/08/78	12/14/78	02/02/79	0.0	0.0	N/A	N/A
380	276-27	01/31/79		03/02/79	0.0	0.0	N/A	N/A
318	277-27	05/31/78		11/10/78	1.138300	0.0	0.0	0.0
319	277-27	06/05/78	06/11/78	11/10/78	0.0	0.0	0.0	0.0
320	277-27	06/16/78		11/10/78	0.0	0.0	0.0	0.0
321	277-27	07/04/78		07/24/78	0.0	0.0	0.0	0.0
323	277-27	08/21/78	10/09/78	11/10/78	0.0	0.0	0.0	0.0
324	282-27	06/15/78		11/10/78	0.0	0.0	0.0	0.0
325	282-27	06/27/78		11/10/78	0.0	0.0	0.0	0.0
326	282-27	07/18/78	08/06/78	11/10/78	0.0	0.0	0.0	0.0
327	282-27	09/02/78	09/16/78	11/10/78	0.0	0.0	0.0	0.0
328	282-27	10/11/78	10/23/78	02/02/79	0.0	0.0	N/A	N/A
329	282-27	11/13/78		02/02/79	0.0	0.0	N/A	N/A
330	284-27	05/23/78	05/25/78	11/10/78	0.0	0.0	0.0	0.0
331	284-27	05/29/78	06/08/78	11/10/78	0.0	0.0	0.0	0.0
332	284-27	06/20/78		11/10/78	0.0	0.0	0.0	0.0
333	284-27	07/02/78		11/10/78	0.0	0.0	0.0	0.0
334	284-27	07/16/78	07/28/78	11/10/78	0.0	0.0	0.0	0.0
335	284-27	08/14/78	09/02/78	11/10/78	0.0	0.0	0.0	0.0
336	284-27	11/17/78	11/30/78	02/02/79	0.0	0.0	N/A	N/A

TABLE 5 (CONTINUED)
RADIOACTIVE TRACER RESPONSE
COALINGA POLYMER DEMONSTRATION PROJECT

I.D.	WELL #	SAMPLE DATE 1	SAMPLE DATE 2	ANALYSIS DATE	COBALT-60 μCi/BBL	IODINE-125 μCi/BBL	SULFUR-35 μCi/BBL	TRITIUM μCi/BBL

337	285-27	05/15/78	05/22/78	11/10/78	0.002300	0.0	0.0	0.0
338	285-27	05/25/78	05/29/78	11/10/78	0.0	0.0	0.0	0.0
339	285-27	05/31/78	06/06/78	11/10/78	0.0	0.0	0.0	0.0
340	285-27	06/04/78		11/10/78	0.0	0.0	0.0	0.0
341	285-27	06/28/78		11/10/78	0.0	0.0	0.0	0.0
342	285-27	07/14/78	07/21/78	11/10/78	0.0	0.0	0.0	0.0
343	285-27	08/03/78	08/27/78	11/10/78	0.0	0.0	0.0	0.0
344	285-27	09/30/78	10/06/78	11/10/78	0.0	0.0	0.0	0.0
345	285-27	10/12/78	10/23/78	02/02/79	0.0	0.0	N/A	N/A
373	285-27	01/17/79	01/26/79	03/02/79	0.0	0.003286	N/A	N/A
378	285-27	01/31/79		03/02/79	0.006230	0.0	N/A	N/A
346	285A27	05/25/78		11/10/78	0.0	0.0	0.0	0.0
347	285A27	05/29/78	05/31/78	11/10/78	0.0	0.0	0.0	0.0
348	285A27	06/05/78	06/10/78	11/10/78	0.0	0.0	0.0	0.0
349	285A27	06/28/78	07/03/78	11/10/78	0.0	0.0	0.0	0.0
350	285A27	07/21/78	08/02/78	11/10/78	0.0	0.0	0.0	0.0
351	285A27	08/23/78	09/07/78	11/10/78	0.0	0.0	0.0	0.0
352	285A27	09/26/78	10/03/78	11/10/78	0.0	0.0	0.0	0.0
353	285A27	11/21/78	12/05/78	02/02/79	0.0	0.0	N/A	N/A
396	294-27	04/27/78		03/02/79	0.0	0.0	N/A	N/A
354	294-27	06/06/78		11/10/78	0.0	0.0	0.0	0.0
355	294-27	06/21/78		11/10/78	0.007600	0.0	0.0	0.0
356	294-27	07/07/78		11/10/78	0.0	0.0	0.0	0.0
357	294-27	08/17/78	09/03/78	11/10/78	0.002400	0.0	0.0	0.0
358	294-27	10/24/78	11/15/78	02/02/79	0.005300	0.0	N/A	N/A
381	294-27	01/15/79	01/25/79	03/02/79	0.0	0.0	N/A	N/A
48	3-8-26	05/23/78	05/26/78	11/10/78	0.0	0.0	0.0	0.0
49	3-8-26	06/02/78		11/10/78	0.0	0.0	0.0	0.0
50	3-8-26	06/04/78		11/10/78	0.0	0.0	0.0	0.0
51	3-8-26	06/09/78		11/10/78	0.0	0.0	0.0	0.0
52	3-8-26	06/14/78		11/10/78	0.0	0.0	0.0	0.0
53	3-8-26	06/20/78		11/10/78	0.0	0.0	0.0	0.0
54	3-8-26	06/26/78		11/10/78	0.0	0.0	0.0	0.0
55	3-8-26	07/01/78		11/10/78	0.0	0.0	0.0	0.0
56	3-8-26	07/06/78		11/10/78	0.0	0.0	0.0	0.0
57	3-8-26	08/12/78	08/28/78	11/10/78	0.0	0.0	0.0	0.0
58	3-8-26	10/18/78		02/02/79	0.0	0.670300	N/A	N/A
59	3-8-26	12/16/78		02/02/79	0.0	4.285000	N/A	N/A
367	3-8-26	01/22/79	01/31/79	03/02/79	0.0	0.077030	N/A	N/A

TABLE 6
PRODUCED POLYMER CONCENTRATIONS
COALINGA POLYMER DEMONSTRATION PROJECT

1978 POLYMER ANALYSES (PPM)-COALINGA WELLS-FOR WEEK OF:															1979 POLYMER ANALYSES (PPM)-COALINGA WELLS-FOR WEEK OF:															
Well No.	Prior	10/1	10/8	10/15	10/22	10/29	11/5	11/12	11/19	11/26	12/3	12/10	12/17	12/24	1/1	1/7	1/14	1/21	1/28	2/4	2/11	2/18	2/25	3/4	3/11	3/18	3/25	4/1	4/8	4/15
1-5-26	12	--	11	6	--	--	--	6	--	10.5	0	--	0	0	--	--	4	0.5	--	7	12	2.5	5							
1-7-26	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--						
1-8-26	--	8	5	7	--	--	--	6	--	8	3.5	--	5.5	--	19	4	4	--	--	8	11.5	2.5	4							
1-9-26	12	2	0	0	--	--	0	--	3	--	9	0	0	0	8	8.5	4	--	8	17	13	4.5	1	3						
1-14-26	--	--	--	--	--	4	--	--	--	8	0	--	--	--	--	--	--	--	--	--	--	--	--							
3-8-26	--	--	--	1	--	2	--	--	3.5	--	0	--	0	--	2	--	--	3	2	9	8	2	--	2						
3-11-26	14	--	9	--	--	4	--	7	--	13.5	3.5	--	2	--	10	--	--	--	--	8	48.5	6	6							
4-6-26	--	--	3	3	--	0	--	--	0	--	2	--	0	--	8.5	--	1	0	--	5	5	4.5	--	4.5						
4-13-26	--	--	--	--	--	7	--	4	4	--	3.5	--	--	--	--	--	--	--	--	--	--	--	--							
4-14-26	--	--	--	--	--	--	--	--	--	10.5	--	--	--	--	--	--	--	--	--	--	--	--	--							
6-10-26	--	--	2	--	--	2	--	2	--	--	--	--	0	--	--	--	--	--	--	--	--	--	--							
14-7-27	--	5	2	--	--	2	--	4	--	3	--	--	--	--	7	--	--	0	--	4	24	2	2							
15-8-27	3	14	5	3	7	1	3	6	4	17	42	1	2	5	--	8	8	6.5	8	19	8	11	11	11						
16-7-27	--	23	20	20	29	26	30	--	42	--	48	54.5	--	88	11	11	3.5	--	11	10	21	16.5	15	21						
1-26	--	--	--	6	--	--	--	4	--	8.5	--	--	0	--	--	0	1	0	--	4	8	--	--							
10-26	--	--	2	--	--	1	--	--	--	13.5	--	--	0	--	--	--	--	--	--	--	--	--	--							
34-27	14	--	2	2	--	4	--	--	--	--	--	--	0	0	10	--	--	--	6	11	7	4.5	--	7						
58-27	10	4	--	2	--	2	--	--	--	0	0	--	--	--	--	4	3.5	--	2	--	--	1	--							
59-27	--	--	--	1	--	--	--	6	--	--	--	0	--	--	--	--	--	0	--	--	--	3	--	11						
71-27	--	--	--	--	10	--	--	--	--	--	--	--	--	--	12	--	--	31	--	--	11.5	--	--	6.5						
92-27	--	--	--	--	--	--	0	--	2	--	--	0	--	0	--	--	5	5	--	0	11	--	2.5							
94-27	--	--	--	--	--	8	10	10	--	--	--	--	--	12	12	--	--	--	--	--	--	--	--							
97-27	--	0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--							
107X-26	--	--	--	--	6	--	--	5	--	4.5	0	--	--	--	--	--	--	--	--	--	--	--	--							
113-27	--	4	3	--	5	1	4	--	5	--	--	0	--	0	5	--	3	0	--	4	--	2.5	6							
114-27	--	--	11	3	--	1	4	--	0	--	10.5	0	--	2	--	4	0	4	--	6	2	2.5								
115-27	--	5	--	4	5	--	2	4	--	--	7.5	12	--	1.5	--	--	--	1	5	--	8	--	2.5							
116-27	--	--	--	--	--	--	--	--	--	14	--	--	--	--	--	--	--	1	--	5.5	15	4.5	--							
118-27	--	--	16	4	--	4	4	--	8.5	3	--	3	1.5	--	6	--	4	1	4	6	2.5	1.5	2							
120-27	--	2	8	--	--	5	--	--	--	--	0	--	--	0	--	--	--	0	--	5	13	2.5	4.5							
121-27	--	--	11	5	--	0	6	--	--	1	--	--	--	--	8	--	--	0	10	7	5	--	6							
127-26	--	--	--	--	--	0	--	12	--	8.5	8	--	--	--	--	--	--	--	--	--	--	--	--							
137-26	--	--	--	--	--	0	4	--	--	3	--	0	--	--	--	--	--	--	--	--	--	--	--							
145-26	--	--	--	--	0	--	2	--	--	8	--	5	--	--	--	--	--	--	--	--	--	--	3							
152-27	--	--	1	--	--	--	2	--	--	--	0	--	--	--	0	--	--	--	0	--	10	--	1.5							
164X-27	--	--	--	--	--	--	--	--	--	1	--	--	--	--	--	--	--	--	--	--	--	--	--							
165-27	--	--	2	2	--	3	--	2	--	--	--	--	0	--	--	10	--	1	--	2	--	0.5	--							
166X-27	--	--	--	--	--	--	--	--	--	0	--	--	--	--	--	--	--	--	--	--	--	--	--							
172-27	--	--	8	17	--	6	12	--	--	--	2	--	--	--	5.5	--	--	--	--	--	--	--	--							
176-27	--	10	6	7	9	19	--	6	--	12	--	--	0	--	--	14	11	--	9	--	--	2.2	--							
187X-27	--	--	--	--	9	--	6	--	--	--	--	--	0	--	--	--	--	--	--	6	--	2.5	--							
207-26	--	--	--	--	2	--	--	--	--	3.5	0	--	--	--	--	--	--	--	--	--	--	--	6							
273-27	--	6	11	--	6	5	--	5	--	4	7	4	0	0	6	--	7	1	--	7	2.5	6.5	--	4.5						
275-27	--	--	5	--	6	4	--	6	0	14	3.5	--	1.5	3.5	7	--	3.5	--	--	7	11.5	2.5	--	5						
276-27	--	--	5	5	--	--	4	--	--	--	--	10	--	--	--	8	--	1	7	--	--	--	4.5							
277-27	--	--	12	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--							
282-27	--	--	1	--	4	--	--	2	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--							
284-27	--	2	5	--	--	2	--	6	--	3.5	--	0	--	--	5	--	1	2	--	3	--	--	--							
285-27	--	17	5	--	8	4	--	--	--	--	2	3	--	--	--	17	5	--	5	5	--	9	2.5							
285A-27	--	--	10	--	--	8	8	--	8	--	2	5.5	--	5.5	9	--	--	5.5	8	--	8	--	3							
294-27	--	--	17	--	35	20	--	15	--	--	20	26.5	--	--	--	10	--	3.5	--	5.5	46	--	6.5							
685A-27	--	--	--	--	--	--	--	--	--	3.5	--	--	--	--	--	--	--	--	--	--	--	--	--							

Table 7
SUMMARY OF LOG CALCULATED POROSITIES
COALINGA POLYMER DEMONSTRATION PROJECT

<u>WELL</u>	<u>E</u>	<u>F</u>	<u>Gc</u>	<u>Gd</u>	<u>X</u>	<u>Y</u>	<u>Hw</u>	<u>Hx</u>	<u>Js</u>	<u>Jv</u>
1-5-26	.245	.245	.229	.221	.245	-	.237	-	.260	
1-7-26	.261	.270	.230	.243	-	.248	.240	-	.244	
1-8-26	.255	.282	.248	.263	.233	.278	.248	.251	-	
2-9-26	.28	.257	.230	.27	.26	.26	.25	.25	.267	
3-8-26	.227	.223	.222	.220	-	-	.203	-	.220	
3-11-26	.234	.223	.24	.23	.245	-	.215	.195	.18	.236
4-6-26	.264	.261	.239	.264	.231	-	.223	.239	.245	
4-13-26	.211	.216	.22	.255	.197	-	.23	.18	.25	
12-7-27	.243	.223	.261	.227	-	.247	.28	.27	.215	
14-7-27	.274	.278	.265	.263	-	.286	.270	.252	-	
15-8-27	.24	.27	.232	.244	.194	-	.239	.206	-	
15-9-27	.24	.26	.25	.26	.24	.26	.25	.25	.246	
16-6-27	.262	.267	.243	.261	-	-	.256	.272	.257	
16-7-27	.254	.284	.25	.258	.26	.268	.257	.228	.224	
256A-27	.227	.259	.261	.227	-	.288	.23	.29	.18	.284
285A-27	.26	.249	.18	.25	.23	-	-	.250	.247	
2-7-26	.236	.273	.224	.265	.233	.22	.234	.23	.23	
12-26	.278	.212	.182	.227	.242	.258	.23	.258	.245	
74-27	.242	.248	-	.18	-	.25	.20	.224	.212	
92-27	.288	.285	.27	.285	.30	-	-	-	-	
93-27	.288	-	.242	-	-	.258	.221	.212	.242	
114-27	.303	.261	.273	.258	-	-	-	.218	.242	
115-27	.267	.267	.261	-	-	.25	.212	.215	.20	
117-27	.300	.258	-	-	-	-	.227	.212	.20	
118-27	.218	-	.215	.227	.246	.261	.20	.212	.212	
182-27	.273	.218	.212	.212	-	-	-	-	-	
16-8-27	.233	.232	.238	.25	.235	.235	.229	.221	.225	
37-26			.242	.239	.197	.212	.212	.258	.197	
32-26			.273	.30	-	-	-	-	-	
6-10-26			.23	.24	.25	-	-	.255	.26	
10-26			.25	.264	.255	-	.275	.218	.25	
187X-27			.225	.225	.225	-	.225	.20	.225	
120-27			.252	.245	.273	.258	.275	.20	.215	
9-7-27			.28	-	-	-	.30	.28	-	
75-27			.30	.225	-	-	-	-	.20	
121-27				.20	-	.25	.30	.22	.21	
265-27				.20	-	-	-	-	-	
95-27							.25	.225	-	
152-27								.20	-	
AVERAGE(1)	0.256	0.253	0.241	0.242	0.240	0.255	0.241	0.232	0.228	0.260
(1) THICKNESS - WEIGHTED AVERAGE					60					

Table 8
AVERAGE CALCULATED WATER SATURATIONS
COALINGA POLYMER DEMONSTRATION PROJECT

WELL	E,F	Gc	Gd	X,Y	Hw	Hx	Js	Jv
1-5-26	39	40	39	54	42	-	38	-
1-7-26	26	42	56	69	49	-	79	-
1-8-26	27	48	34	59	54	74	-	-
2-9-26	58	48	78	81	86	75	91	-
3-8-26	43	44	76	-	28	-	69	0
3-11-26	42	40	82	38	35	54	27	55
4-6-26	38	40	86	69	89	92	78	-
4-13-26	69	21	38	-	27	45	38	-
12-7-27	39	12	19	29	39	43	60	40
14-7-27	36	45	38	48	48	80	46	82
15-8-27	32	41	45	38	54	72	-	-
15-9-27	51	18	48	87	52	98	32	96
16-6-27	38	38	50	-	42	42	63	-
16-7-27	28	52	52	41	55	75	-	-
256A-27	78	36	37	87	42	48	100	70
285A-27	59	63	46	65	-	46	100	88
AVERAGE (1)	39	37	49	55	50	63	57	66

(1) POROSITY-THICKNESS WEIGHTED AVERAGE

2V00997-00

Table 9
AVERAGE GAS SATURATIONS
COALINGA POLYMER DEMONSTRATION PROJECT

	E,F	Gc	Gd	X,Y	Hw	Hx	Js	Jv
1-5-26	NO DESATURATION							
1-7-26	1						2	
1-8-26	1							
1-9-26	NO DESATURATION							
2-9-26	NO DESATURATION							
3-8-26					14			
3-11-26		8					22	2
4-6-26	1				1			
4-13-26	11	2			10	1	2	
9-7-27		15			56			
12-7-27	32	75	68	58	48	56	27	
14-7-27	21	28	14	5	11	4		
15-6-27	16	23	17	22	29	20	32	
15-8-27	28							
15-9-27	5	15	1			1		
16-6-27	3	8						
16-7-27	1	4						
256A-27	9	51	50		45	39		17
285A-27	28	24	19	22		41		
AVERAGE(1)	9	20	9	12	17	6	13	12
(1) THICKNESS-WEIGHTED AVERAGE								

2V00958-00

Table 10
RESERVOIR VOLUME OF IMMEDIATE PILOT AREA
COALINGA POLYMER DEMONSTRATION PROJECT

<u>SAND(S)</u>	<u>RESERVOIR VOLUME (ACRE-FT.)</u>
E,F	3,775.9
Gc	2,683.2
Gd	1,795.6
X	575.2
Y	1,423.4
Hw	3,511.0
Hx	2,361.9
Js	2,094.6
Jv	924.5
	<hr/>
TOTAL	19,145.3

6/25/79-8 LR

Table 11
SATURATION AND VOLUMES
IMMEDIATE PILOT AREA
COALINGA POLYMER DEMONSTRATION PROJECT

SAND	ACRE-FEET	POROSITY	PORE VOLUME (BBL S)	SOIL	S WATER	S GAS	AS OF JULY 1, 1976		
							OIP (RB)	WIP (RB)	GIP (RB)
E,F	3775.9	.255	7469800	.525	.385	.090	3921645	2875873	672282
Gc	2683.2	.241	5016700	.429	.367	.204	2152164	1841129	1023407
Gd	1795.6	.242	3371100	.417	.489	.094	1405749	1648468	316883
X	575.2	.240	1071000	.360	.553	.087	1399284	2149456	338160
Y	1423.4	.255	2815900						
Hw	3511.0	.241	6564400	.382	.497	.121	2507601	3262507	794292
Hx	2361.9	.232	4251180	.205	.627	.168	871475	2665440	714185
Js	2094.6	.228	3705000	.373	.571	.056	1381965	2115555	207480
Jv	924.5	.260	1864800	.213	.659	.128	397203	1228903	238694
TOTALS	19145.3		36129800				14037086	17787331	4305383
AVERAGE SATURATIONS							$\bar{S}_o = .39$	$\bar{S}_w = .49$	$\bar{S}_g = .12$

Table 12
APPROXIMATION OF ORIGINAL OIL SATURATION
FROM WELLS CORED WITH OIL
COALINGA POLYMER DEMONSTRATION PROJECT

SAND(S)	152-27			80A-27			103-34			AVERAGE Soi
	So (1)	Sw (1)	Soi (2)	So (1)	Sw(1)	Soi (2)	So (1)	Sw (1)	Soi (2)	
E,F	.338	.395	.605	—	—	—	—	—	—	.605
Gc	.690	.237	.763	—	—	—	—	—	—	.763
Gd	.503	.247	.753	—	—	—	.399	.379	.621	.687
X,Y				—	—	—	.386	.486	.514	.514
Hw				—	—	—	.581	.250	.750	.750
Hx				.319	.613	.387	.669	.306	.694	.541
Js				.546	.358	.642	.570	.193	.807	.725
Jv				—	—	—	.484	.310	.690	.690

(1) UNSTRESSED SATURATIONS

(2) APPROXIMATE ORIGINAL OIL SATURATION = $1 - S_w$

6/25/79-11 LR

Table 13
INITIAL VOLUMETRIC AVERAGE OIL SATURATION
COALINGA POLYMER DEMONSTRATION PROJECT

	<u>Soi (1)</u>	<u>PORE VOLUME (MB)</u>	<u>PVSoi (MB)</u>
E,F	.605	7,469.8	4,519.2
Gc	.763	5,016.7	3,827.7
Gd	.687	3,371.1	2,315.9
X,Y	.514	3,886.9	1,997.9
Hw	.750	6,564.4	4,923.3
Hx	.541	4,251.1	2,299.8
Js	.725	3,705.0	2,686.1
Jv	.690	<u>1,864.8</u>	<u>1,286.7</u>
		36,129.8	23,856.6

$$\overline{\text{Soi}} = \frac{23,856.6}{36,129.8} = .660$$

(1) SEE TABLE 12

6/25/79—5 LR

Table 14
PROJECT PARAMETERS
COALINGA POLYMER DEMONSTRATION PROJECT

	<u>1975 ESTIMATE</u>	<u>1979 ESTIMATE</u>
PROJECT AREA – ACRES	132	149
AVERAGE THICKNESS – FEET	125	129
POROSITY	0.265	0.243
INITIAL AVG. OIL SATURATION	0.650	0.660
AVG. OIL SATURATION (3)	0.540 (1)	0.390 (2)
AVG. WATER SATURATION (3)	0.330 (1)	0.490 (2)
AVG. GAS SATURATION (3)	0.130 (1)	0.120 (2)
WATERFLOOD RESIDUAL OIL SATURATION – FRACTION	0.235 (1)	0.28 ± .04 (2)

(1) USED IN SIMULATION STUDY – PETROPHYSICS

(2) FROM CURRENT PETROPHYSICAL ANALYSIS

(3) AS OF JULY 1, 1976

6/25/79—13 LR

Table 15

**PROJECT VOLUMES
COALINGA POLYMER DEMONSTRATION PROJECT**

	<u>1975 ESTIMATE</u>	<u>1979 ESTIMATE</u>
PORE VOLUME	33,922 MB	36,130 MB
ORIGINAL OIL IN PLACE (1)	20,607 MSTB	22,286 MSTB
ZONE II PRODUCTION (2)	18,000 MSTB	16,424 MSTB
OIL IN PLACE (2)	17,780 MSTB	13,680 MSTB
MOVEABLE OIL IN PLACE (2)	10,295 MSTB	3859 ± 1403 MSTB
CONTINUED PRIMARY	710 MSTB	710 MSTB
DIFFERENTIAL WATERFLOOD (3)	2040 MSTB	—
DIFFERENTIAL POLYMER FLOOD (3)	805 MSTB	—

(1) PRIOR TO ANY PRODUCTION

(2) AS OF JULY 1, 1978

(3) ORIGINAL PREDICTIONS

6/25/79-10 LR

Table 16
1978 ENDPOINT RELATIVE PERMEABILITY DATA⁽¹⁾
SYNTHETIC CRUDE AND BRINE FROM DEIONIZED WATER

<u>SAMPLE (2)</u> <u>DEPTH</u>	<u>SAND</u>	<u>STRESSED</u> <u>POROSITY</u>	<u>K_b, md</u> <u>(S_w = 100%)</u>	<u>K_{oi} (3)</u> <u>(md)</u>	<u>S_{wr} (%)</u> ⁽³⁾	<u>K_w (3)</u> <u>(md)</u>	<u>S_{orw} (%)</u> ⁽³⁾	<u>K_w @ S_{orw}</u> <u>K_{oi} @ S_{wr}</u>
1970	Gc	.261	120	276	29.7	7.0	39.7	.025
2110	Hx	.277	86.8	355	32.4	6.8	34.0	.019
2110	Hx	.268	84.4	315	16.0	5.6	31.7	.018
2170	J _s	.215	9.1	51.5	59.9	0.72	22.8	.014

(1) ISOSTATIC STRESS OF 900 PSIG

(2) WELL 16-6-27

(3) BRINE CONTAINS 8 g NaCl/LITER OF WATER AND
OIL VISCOSITY APPROXIMATELY 15.2 CPS

6/25/79-3 LR

Table 17

**1979 ENDPOINT RELATIVE PERMEABILITY DATA⁽¹⁾
COALINGA CRUDE AND SYNTHETIC WATERS**

<u>SAMPLE (2)</u> <u>DEPTH</u>	<u>SAND</u>	<u>Kb, md (3)</u> <u>(Sw = 100%)</u>	<u>Koi (4)</u> <u>(md)</u>	<u>Swr (%)</u>	<u>Kw (4)</u> <u>(md)</u>	<u>Sorw (%)</u>	<u>Kw (5)</u> <u>(md)</u>	<u>Sorw (%)</u>	<u>Ko (6)</u> <u>(md)</u>	<u>Sw (%)</u>	<u>Kw @ Sorw(8)</u> <u>Koi @ Swr</u>
2109	Hx	69.0	146	31.0	12.6	26.0	7.2	~ 20	—	—	.086
2004	Gd	83.1	362	40.8	29.6 ⁽⁷⁾	—	26.4	—	197	30.4	.082
2004	Gd	119.0	223	32.5	7.3 ⁽⁷⁾	—	3.9	—	65.7	27.3	.033

(1) ISOSTATIC STRESS OF 900 PSIG

(2) WELL 16-6-27

(3) SYNTHETIC FORMATION WATER ($Ca^{++}/Na^{+} = .018$)

(4) COALINGA CRUDE AND SYNTHETIC FORMATION WATER ($Ca^{++}/Na^{+} = .018$)

(5) CORE FLOODED WITH SYNTHETIC USBR WATER ($Ca^{++}/Na^{+} = .16$) AFTER WATERFLOOD WITH FORMATION WATER

(6) RESATURATING CORE WITH COALINGA CRUDE AFTER WATERFLOODS

(7) EMULSION PRODUCED DURING WATERFLOOD WITH SYNTHETIC FORMATION WATER

(8) Kw @ Sorw FOR SYNTHETIC FORMATION WATER ($Ca^{++}/Na^{+} = .018$)

6/25/79-1 LR

Table 18
ENDPOINT RELATIVE PERMEABILITY DATA⁽¹⁾
BEFORE DARLEY TREATMENT

<u>SAMPLE (2)</u> <u>DEPTH</u>	<u>SAND</u>	<u>Kb, md (3)</u> <u>(Sw = 100%)</u>	<u>Koi (4)</u> <u>(md)</u>	<u>Swr (%)</u>	<u>Kw (5)</u> <u>(md)</u>	<u>Sorw (%)</u>	<u>K DARLEY</u> <u>(md)</u>
1986.7	Gd	93.2	151	38.8	36.3	~25.	32.8
1970	Gc	101	256	40.2	67.0	~22.	(6)

(1) ISOSTATIC STRESS OF 900 PSIG

(2) WELL 16-6-27

(3) SYNTHETIC FORMATION WATER ($\text{Ca}^{++}/\text{Na}^{+} = .018$)

(4) COALINGA CRUDE AND SYNTHETIC FORMATION WATER ($\text{Ca}^{++}/\text{Na}^{+} = .018$)

(5) WATERFLOOD WITH 35,000 PPM BRINE ($\text{Ca}^{++}/\text{Na}^{+} = .02$)

(6) SAMPLE NOT DARLEY TREATED

6/25/79-6 LR

Table 19
BRINE PERMEABILITY DATA (1)
AFTER DARLEY TREATMENT

1986.7' (Gd SAND)(2)		1970' (Gc SAND)(2)	
SALINITY (3) (ppm)	PERMEABILITY (md)(4)	SALINITY (3) (ppm)	PERMEABILITY (md)(5)
40,000	60.7	40,000	65.5
8,300	63.1	9,200	70.1
2,200	69.8	2,000	72.9
900	75.8	850	72.3
540	78.7	540	73.3
260	87.9 (6)	260	75.7 (7)

(1) ISOSTATIC STRESS OF 900 PSIG

(2) WELL 16-6-27

(3) $\text{Ca}^{++}/\text{Na}^{+}$ = CONSTANT = 0.15 (I.E. USBR RATIO)

(4) BASE WATER PERMEABILITY AT $\text{Sorw} = 36.3$ md (DARLEY TREATED SAMPLE)

(5) BASE WATER PERMEABILITY AT $\text{Sorw} = 67.0$ md (SAMPLE NOT DARLEY TREATED)

(6) RESIDUAL OIL SATURATION = 12.9 PERCENT

(7) RESIDUAL OIL SATURATION = 12.0 PERCENT

6/25/79-2 LR

Table 20
LABORATORY STUDIES SHOWING
EFFECT OF SHEAR ON VISCOSITY
(300 PPM KELZAN SOLUTION)

<u>SHEAR PRESSURE (PSI)</u>	<u>SHEAR RATE ($\gamma N \times 10^6 \text{ SEC}^{-1}$)</u>	<u>PERCENT VISCOSITY LOSS</u>	
		<u>RUN 1</u>	<u>RUN 2</u>
100	0.40	0	0
300	0.86	23.2	25.7
500	1.1	41.9	37.8
700	1.4	46.5	44.6
900	1.7	48.8	51.3

6/26/79-7 LR

Table 21
LABORATORY STUDIES SHOWING
EFFECT OF MULTIPLE SHEARING ON VISCOSITY
(300 PPM KELZAN SOLUTION FROM UNSHEARED CONCENTRATE)

<u>TIMES SHEARED @ 100 PSI</u>	<u>PERCENT VISCOSITY LOSS</u>	
	<u>RUN 1</u>	<u>RUN 2</u>
1	0	0
2	9.3	9.4
3	16.3	13.5
4	25.6	16.2
5	25.6	17.5

6/25/79-9 LR

Table 22
LABORATORY STUDIES SHOWING
EFFECT OF MULTIPLE SHEARING ON VISCOSITY
(300 PPM KELZAN SOLUTION FROM ONCE-SHEARED CONCENTRATE)

<u>TIMES SHEARED @ 100 PSI</u>	<u>PERCENT VISCOSITY LOSS</u>	
	<u>RUN 1</u>	<u>RUN 2</u>
1	0	0
2	4.6	4.2
3	7.0	8.5
4	11.6	10.6
5	11.6	10.6

6/25/79-15 LR

Table 23
FIELD STUDIES SHOWING EFFECT OF
DIFFERENTIAL PRESSURE ON VISCOSITY

SAMPLE	PRESSURE (PSI)	VISCOSITY , CP (@ 7.3 SEC ⁻¹)			
		RUN 1		RUN 2	
		W/O BOMB	WITH BOMB	W/O BOMB	WITH BOMB
PUMP SUCTION	—	5.0	—	5.5	—
PUMP DISCHARGE	600	3.2	5.0	—	5.5
BEAM 1 DISCHARGE	500	3.3	4.9	—	5.5
BEAM 2 DISCHARGE	400	3.4	4.7	—	5.1
BEAM 3 DISCHARGE	300	3.8	4.7	—	5.0
BEAM 4 DISCHARGE	200	4.3	4.5	—	4.8
BEAM 5 DISCHARGE	100	4.3	4.3	—	4.8
BEAM 6 DISCHARGE	50	4.3	4.3	—	4.8
BEAM 7 DISCHARGE	0	4.3		4.8	—

6/26/79—20 LR

Table 24
SAMPLING PROCEDURES
SAMPLE ACCUMULATING CHAMBER
FOR SHEAR -SENSITIVE SOLUTIONS

(SEE FIGURE 38)

1. ATTACH EMPTY PRESSURE VESSEL TO INJECTION LINE (OR CAN BE PERMANENTLY INSTALLED).
2. START FILLING PRESSURE VESSEL.
3. AS SOON AS THE LINE PRESSURE AND THE VESSEL PRESSURE HAVE EQUALIZED, SLOWLY OPEN THE NEEDLE VALVE ON TOP OF THE PRESSURE VESSEL.
4. DISPLACE A MINIMUM OF FIVE VESSEL VOLUMES WHILE MAINTAINING A DIFFERENTIAL PRESSURE OF 50 PSI OR LESS.
5. CLOSE THE OUTLET VALVE ON THE PRESSURE VESSEL FIRST, THEN THE TWO INLET VALVES.
6. DISCONNECT THE PRESSURE VESSEL.
7. BLEED THE PRESSURE FROM THE TOP VALVE OF THE PRESSURE VESSEL AND OBTAIN SAMPLE BY ALLOWING FLUID TO DRAIN OUT BOTTOM VALVE.

NOTE: DEPENDING ON LINE PRESSURE AND SAMPLING VALVES (FULL OPENING, NEEDLE VALVES, ETC.), VISCOSITY LOSSES AS HIGH AS 30% HAVE BEEN OBSERVED WHEN SAMPLING DIRECTLY FROM LINES WITHOUT USING THE ABOVE PROCEDURE.

6/25/79-12 LR

Table 25
FIELD DATA COMPARING INJECTION PUMP
VISCOSITY AND WELLHEAD VISCOSITY

<u>SAMPLE LOCATION</u>	<u>PRESSURE (PSI)</u>	<u>VISCOSITY , CP (@ 7.3 SEC ⁻¹)</u>
INJ. PUMP DISCHARGE	660	6.8
WELLHEAD 2-7-26	460	6.0
WELLHEAD 2-9-26	120	4.6
WELLHEAD 15-6-27	480	6.4
WELLHEAD 15-9-27	450	6.1

6/25/79-14 LR

Table 26
FIELD DATA SHOWING
EFFECT OF DOWNHOLE SAMPLER⁽¹⁾ ON VISCOSITY

<u>SAMPLE</u>	<u>SAMPLING DEPTH</u>	<u>VISCOSITY, CP (@ 7.3 sec⁻¹)</u>
WELL 2-7-26	2195 FT.	2.8
WELL 2-9-26	2247 FT.	3.2
WELL 15-6-27	1973 FT.	2.6
WELL 15-9-27	1939 FT.	2.8
POLYMER TANK NO. 1	—	4.8

(1) PRIOR TO MODIFICATION OF DOWNHOLE SAMPLER (FIGURE 39)

6/25/79-4 LR

COALINGA FIELD INDEX MAP – POLYMER DEMONSTRATION PROJECT

FIGURE 2

TYPE LOG
COALINGA FIELD
ZONE II RES.

2200420-01

FROM K7-1-904

FIGURE 4

COALINGA POLYMER PILOT PERFORMANCE CURVE IMMEDIATE PILOT AREA

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FIGURE 5

PRODUCTION PERFORMANCE
PATTERN PRODUCTION WELLS
COALINGA POLYMER PILOT

DOWNDIP

--- OIL

— GROSS

CENTRAL

FIGURE 9

FIGURE 10

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INJECTION WELL CURVE WELL 2-7-26

INJECTION WELL CURVE WELL 2-9-26

INJECTION WELL CURVE WELL 15-6-27

INJECTION WELL CURVE WELL 15-9-27

LOGGING OBSERVATION WELL CHANGES
WELL 16-6-27
COALINGA POLYMER DEMONSTRATION PROJECT
MAY 1978 THROUGH APRIL 1979

(ONLY MINOR CHANGES SEEN ON OTHER LOGS RUN DURING THIS TIME)

2200935-00

FIGURE 14

FIGURE 16.

FIGURE 17

**COALINGA POLYMER PROJECT
GR LOGS LOGGING OBSERVATION WELL 16-6-27 FOR
DETECTION OF RADIOACTIVE COBALT INJECTED IN WELL 15-6-27**

SHEET 1

97

FIGURE 18

COALINGA POLYMER PROJECT

GR LOGS IN LOGGING OBSERVATION WELL 16-6-27 FOR
DETECTION OF RADIOACTIVE COBALT INJECTED IN WELL 16-6-27

SHEET 2

FAN CHART FOR GAS SATURATION
COALINGA POLYMER DEMONSTRATION PROJECT

2200553-00

FIGURE 22

WELL 4-13-26
DUAL-SPACED NEUTRON LOGS

FIGURE 23

WELL 3-11-28
DUAL-SPACED NEUTRON LOGS

2200888-00

WELL 285A-27
DUAL-SPACED NEUTRON LOGS

WELL 16-6-27
DUAL-SPACED NEUTRON LOGS

2200887-00

GRAVITY DRAINAGE MODEL
IMMEDIATE PILOT AREA
COALINGA POLYMER DEMONSTRATION PROJECT

FIGURE 27

EFFECT OF GRAVITY DRAINAGE
COALINGA POLYMER DEMONSTRATION PROJECT

FIGURE 28

CORE DATA BY WELL

S₀ UNSTRESSED OR S₀ CORRECTED

COALINGA POLYMER DEMONSTRATION PROJECT

2200596-00

CORE DATA BY SAND
S₀ UNSTRESSED OR S₀ CORRECTED
COALINGA POLYMER DEMONSTRATION PROJECT
EAST COALINGA FIELD
FRESNO COUNTY, CALIFORNIA

2200595-00

113
PERMEABILITY, md

FIGURE 33

114

FIGURE 34

FIGURE 35.

2200947-00 6/79

FIGURE 36

PRESSURE REGULATING AND SAMPLING APPARATUS FOR SHEAR SENSITIVE FLUIDS

SAMPLE ACCUMULATING CHAMBER FOR SHEAR SENSITIVE FLUIDS

PARTS NEEDED

<u>NUMBER</u>	<u>QUANTITY</u>	<u>ITEM</u>
---------------	-----------------	-------------

1	2	1/4" NEEDLE VALVE (OUTLET VALVE)
2	2	0-600 PSI. PRESSURE GAUGE
3	1	1800 PSI. SAMPLE VESSEL
4	1	1/4" PRESSURE RELIEF VALVE
5	2	1/2" FULL OPENING INLET VALVE (2500 PSI. + FOR STRENGTH)
6	1	1/2" UNION 2500+ PSI.
7	-	1/2" SCH 80 PIPE NIPPLES AND FITTINGS
8	1	1/2" TO 1/4" REDUCER

MODIFIED BOTTOMHOLE SAMPLER
COALINGA POLYMER DEMONSTRATION PROJECT

2200933-00

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