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PROJECT EVALUATION: PENN GRADE MICELLAR DISPLACEMENT PROJECT

Work Performed for the Department of Energy
Under Contract No. DE-AC19-80BC10033

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SUMMARY

The Penn Grade Micellar Displacement Project tested the micellar/polymer flooding process in a low permeability (7.65 md average permeability) portion of the Bradford Third Sand reservoir. This test, herein referred to as the Lawry Test, followed the successful test of the micellar/polymer flooding process in a higher permeability (82 md) portion of the Bradford Third Sand reservoir (Bingham Test). The Lawry Test failed technically and economically as an oil recovery process. Total oil recovery amounted to about 5.2 percent of the oil-in-place at the time of micellar injection. Project failure did not appear to be the result of poor operational practice.

Project participants recognized the difficulty of applying the micellar/polymer process in such a low permeability reservoir (7.65 md) at the initiation of the project. Nevertheless, the large reserve of oil trapped within the low permeability portions of the Bradford Field made the project attractive. There appeared to be three major reasons for project failure:

1) Reservoir Heterogeneity,
2) Adverse Ion Exchange Phenomena, and
3) High Sulfonate Loss.

Data from Phase I testing, injection well tracer surveys, injection well logging, produced chloride concentrations and the Phase II evaluation well confirmed that only a small portion of the Lawry pilot was contacted by injected fluids. This portion of the reservoir may have been from 3 to 6 feet of the net 29 feet of pay in the reservoir. Produced salinity and hardness levels suggested the occurrence of adverse ion exchange phenomena. Adverse ion exchange behavior would be expected to have resulted in severe sulfonate loss, and low oil recovery. Additional data are needed to confirm this conclusion.

In addition, injectivity was low throughout the project. Significant losses of injectivity were continually experienced throughout polymer injection. In the absence of the above problems, it is likely that the process would not be practical in areas typical of Lawry because of low injectivity.

INTRODUCTION

The Penn Grade Micellar Displacement Project was a tertiary oil recovery pilot test of the micellar/polymer process in a low permeability portion of the Bradford Field, located in McKean County, Pennsylvania. The project was performed in a 24-acre tract, known as the Lawry Farm, in the Bradford Third Sand. Funding was provided at the 50 percent level by the Department of Energy (DOE) with the balance of costs shared equally by the Pennzoil Company, Quaker State Oil Refining Corporation and Witco Chemical Corporation.[1-3] Pennzoil Company operated the pilot test. Fluid design work was performed by Marathon Oil Company. The test was patterned after the earlier, successful, Bingham test of the micellar/polymer process. The Bingham test was performed in a more permeable portion of the Bradford Third Sand. The purpose of this report is to review and evaluate Lawry project performance and to compare performance to the Bingham Test.

Background Information

In 1871, production began in the Bradford Field with subsequent waterflooding beginning in 1926. As of March 1978, the Bradford Field was about 85,000 acres in size and had produced an estimated 660 million barrels of oil. The major reservoir in the field is the Bradford Third Sand. Much (about 50 percent) of the Bradford Third Sand has relatively low permeability. It is a hard, brown, fine-grained sandstone and is a member of the Chemung formation.

Pilot Area Description

The micellar pilot area was located on the Lawry Farm, Foster Township, McKean County, Pennsylvania. Pattern development is shown in Figure 1. The site comprised 24 acres with 41 development wells drilled on one and one-half acre, five-spot patterns. Nine enclosed five spots were surrounded by 16 producing wells in the test area. The enclosed five-spots comprised Farm A and the outer, unbounded five-spots comprised Farm B. Reservoir characteristics of the Lawry Farm are summarized in Table 1. Average air permeability was rather low (about 8 md) in this portion of the Third Sand.

PROJECT DESIGN

The Penn Grade Micellar Displacement Project (herein to be referred to as the Lawry Test) was designed in two phases. Phase I was to determine the injectivity characteristics of micellar/polymer fluids in a low permeability portion of the Bradford Third Sand. With acceptable injection rates in Phase I, Phase II would include developing the pilot area and conducting the micellar/polymer oil displacement test in the 24-acre area. Phase I was estimated to require one year and Phase II work was estimated to require four years to complete.

Phase I

Phase I work required the drilling, casing and completion of an injection well (H-68). Well H-68 was located about 400 feet north and east of Well H-90. The well was completed as an open hole and shot with 155 quarts of liquid nitroglycerin. Reservoir characteristics in the well area were established by logging and well testing so as to determine if this region were representative of the pilot area. Injection facilities for micellar and polymer fluids were designed and constructed. Plastic pipe and/or plastic-coated pipe was used in the construction of surface facilities. Epoxy-coated tanks were used for fluid storage. Injected fluids were filtered such that micellar and polymer fluids passed a 0.45 micron millipore test. Quantities of fluids injected into H-68 in Phase I are summarized in Table 2. A total of 10,384 barrels of fluid was injected in Phase I. Injection pressures and rates are summarized in Figure 2.

During pre-slug water injection, pressure fall-off tests (PFOT), tracer surveys, and step-rate tests were performed. The PFOT indicated a flow capacity of 34.0 md-feet with a skin factor of -3.1 to -4.2. Type curve analysis of PFOT data indicated the presence of a fracture. Radioactive tracer surveys indicated that most of the injected fluids were entering a four to eight foot pay section in the mid-portion of the reservoir. Step-rate tests did not indicate pressure parting of the reservoir at injection rates of from 11 to 201 barrels per day and wellhead pressures of up to 1,000 psig. Typically water was injected at about 40 barrels per day.

Micellar fluid was prepared at the composition listed in Table 3 and filtered through a diatomaceous earth (DE) filter. Viscosity of the fluid was 11.4 cps at 68°F. Injection was stable at about 20 barrels per day with a wellhead pressure of about 920 psig.

Two biopolymer solutions were injected. The first contained about 350 ppm (7 cps viscosity) of a custom-prepared biopolymer broth. The second solution contained about 500 ppm (10 cps viscosity) biopolymer. Both solutions were DE filtered. Step-rate tests indicated formation parting at about 1,165 psig wellhead pressure during polymer injection. At this critical wellhead pressure of 1,165 psig, the 7 cps polymer solution had a maximum injection rate of 35 barrels per day and the 10 cps polymer solution had a maximum injection rate of 28 barrels per day.

Following polymer injection the well was returned to water injection. Water was injected at 20 barrels per day for the first four days. After that, water rate was increased to 30 barrels per day at a wellhead pressure of about 1,025 psig.

Phase I tests were considered to be successful. Injection rates for the MarathonR process fluids were considered acceptable[3] and work proceeded to Phase II.

Phase II

A total of 25 producing and 16 injection wells were drilled to prepare the Lawry Farm for pilot operations. All 16 injectors and the center producer (H-102) were cored. Injection and production wells were completed as open holes. After logging, wells were stimulated with from 140 to 195 quarts of nitroglycerin per well. Thirteen old producing wells in the pilot area were plugged and abandoned.

Injection facilities, DE filtration equipment, mixing equipment, production equipment, etc., are described in detail in the second and third annual reports.[2,3] Equipment was designed so as to minimize corrosion. PVC tubing, epoxy-coated vessels, etc., were used throughout facilities so as to protect injected fluids from corrosion and contamination. In addition, a small laboratory was constructed on-site to monitor the quality of injected fluids.

A rather extensive transient testing program was designed for the pilot area. This program included fluid level measurement, interference testing and a pressure fall-off testing program. Fluid level testing and interference testing indicated that the pilot area was generally heterogeneous and anisotropic. This directional, permeability trend was determined to be in a northwest-southeast direction. Stabilized reservoir pressure in the pilot area was 467.2 psi with a gradient of 200 psi occurring across the pilot area. An injection well logging program revealed that most injected fluids entered thin, high permeability zones occurring at the top of the sand interval. The pilot pattern was oriented 45 degrees off north so as to minimize regional natural fracture system effects known to exist. Details of the analysis of this test program are provided in the Third Annual Report.[3]

Laboratory Work

Marathon Oil Corporation performed laboratory design work. Fluids were formulated and screened in bench-top testing. More promising fluids were core tested in radial core tests in two-inch thick, six-inch diameter cores from the project area. Details of the core test procedures were provided in the Second Annual Report.[2] Results from at least 39 core tests were reported. The data determined the most cost-effective micellar fluid to have the composition described in Table 4. Neodol, primary amyl and normal butyl alcohols were added (from 0.90 to 1.77 volume percent) to this composition to stabilize the fluid system. Lawry water (a fresh water) composition is listed in Table 5. Original lab work was based on the use of Neodol 23-3A (manufactured by Shell Oil Co.). This material was not available when the project fluid injection began. Additional study indicated that either Neodol 25-3A or Neodol 25-3S could be substituted for Neodol 23-3A.

Field mixed slug performance data are summarized in Figure 3.[3] In this figure, final oil saturation (SOF), after micellar/polymer injection, is plotted against micellar slug size in percent pore volume. These radial core tests were performed at median flow rates varying from 0.256 feet per day to 0.344 feet per day. Data suggested a slug size of about 13 percent pore volume for maximum oil recovery. The most cost effective slug size was selected by project participants to be nine percent pore volume.

Improved oil displacement was noted when cores were injected with a higher salinity brine prior to micellar injection. The optimum concentration of this brine was determined to be 50,000 ppm sodium chloride. This is consistent with the somewhat low, average equivalent weight of the mixed sulfonates in the field slug. From Witco product information data, the sulfonate mixture, as specified in Table 4, would be expected to have an average equivalent weight of 395.

Pennzoil Company, in conjunction with Witco Chemical Corporation and Quaker State Refining Corporation, had developed biopolymers in a broth form. Both products were tested for possible use in the Lawry test.

The Pennzoil/Witco broth was used in Phase I injection. Concern about the availability and consistency of products led to its rejection for use in Phase II. Field and laboratory experience with Kelzan, a biopolymer in powder form, indicated it to be suitable. Filtration and hydration techniques were improved. Kelzan solutions which consistently passed a 0.45 micron filtration were prepared. Based on solution quality and product availability, Kelzan was selected for the project. Formaldehyde (250 ppm) was added to injected polymer solutions to prevent bacterial degradation.

Proposed Injection Sequence

Based upon laboratory work, the fluid injection sequence outlined in Table 6 was agreed upon. As designed, a 10 percent pore volume (PV) slug of preflush brine (50,000 ppm NaCl) was to be followed by a nine percent PV slug of micellar fluid. These fluid banks were to be chased by a graded polymer bank composed of a 10 percent PV slug of 9 ± 0.5 cps (500 ppm) polymer, a 51 percent PV slug of 5.5 ± 0.5 cps (350 ppm) polymer, and a 30 percent PV slug of 1.8 ± 0.2 cps (100 ppm) polymer. There was no prediction published as to the expected performance from this sequence of fluid injection in the Lawry Test.

PHASE II - OPERATIONS[3,5]

Quantities of fluids actually injected into the Lawry Project are summarized in Table 6. Project injection rates are summarized in Figure 4.[5] Injection rates varied from well to well during brine injection. Brine injection was continued until each pilot well had accepted at least the specified 10 percent slug. As a result, the overall preflush brine injection was 16.6 percent instead of 10 percent PV.

The injected brine varied in concentration from about 45,000 ppm to about 57,000 ppm sodium chloride. Well tests, performed during brine injection, indicated no skin damage. Injection surveys performed on wells H-69, H-70, H-72, H-73, H-76, H-77, H-80, H-82 and H-83 indicated that most of the injected brine entered a relatively thin, high permeability section at the top of the reservoir. Once production began, the total injection rate stabilized at about 1,100 barrels per day with a plant pressure of about 300 psig.

A total of 1,079 barrels of fresh water was injected between the preflush brine and micellar fluid so as to clean preflush brine out of the injection facilities. Micellar fluid injection began on September 12, 1977. Injection rates rapidly declined and stabilized at an average of 353 barrels per day for the total project. Plant pressure rapidly increased from 300 psig to about 1,100 psig. Injected micellar fluid viscosity varied from 7.8 to 9.0 cps. Injected fluid samples consistently passed the 0.45 micron filtration test. Efforts to equalize injection rates into individual wells were unsuccessful. Because of this, wells were converted to polymer injection after receiving their allotted portions of micellar fluid. This overlapping section of both micellar fluid and polymer "spike" occurred in the pilot area between February 17, 1978 and April 11, 1978. The total micellar slug injected was 9.4 percent of the total pore volume. Well tests indicated no abnormal behavior occurring during micellar slug injection.

"Spike" polymer was prepared as a 9 ± 0.5 cps (500 ppm) solution and "body" polymer was prepared as a 5.5 ± 0.5 cps (350 ppm) solution. Polymer viscosities were determined in a Brookfield LVT viscometer at six rpm. Injected polymer was reported to be consistently maintained within viscosity and filtration specifications. Polymer solutions were prepared by:

1) Preparing a 6,000 ppm concentrate using dry polymer and Lawry supply water,
2) Shearing the concentrate at high pressure conditions,
3) Diluting to the desired concentration with supply water, and
4) Filtering through a DE filter.

Chlorination of supply water and the addition of 250 ppm formaldehyde appeared to prevent biological degradation of injected polymer solutions. Coils of either 1/4-inch or 3/16-inch tubing, installed on injection wellheads, controlled individual well rates. A 15.3 percent pore volume (105,148 barrels) slug of "spike" polymer was injected. This was followed by a 25.5 percent pore volume (174,806 barrels) slug of "body" polymer. Injectivity continually declined during polymer injection.

Injectivity Problems

The major operational problem encountered was that of declining polymer injection rates. Typical injection rates for the various fluids are listed in Table 7 for Phase I and Phase II operations. Rates in Phase I were considered acceptable.[3] Average preflush brine and micellar fluid injection rates in Phase II operations were equal to or somewhat higher than Phase I rates. However, polymer injection rates were lower in Phase II (roughly one-half). For wells H-69, H-71, H-72, H-74, H-77 and H-80 average rates were quite low during polymer injection. Rates in these wells averaged from about 8 barrels per day to about 14 barrels per day during polymer injection. It is interesting to note that the best oil producer, H-102, was surrounded by wells (H-69, H-76, H-77, and H-80) that had lower average injection rates of 8.6, 20.4, 7.7 and 8.4 barrels per day during polymer injection.

Pressure dissipation tests performed on injection wells were reported. No abnormal well behavior was interpreted.[5] Because of decreasing polymer injection rates, wells H-77 and H-80 were stimulated in attempts to improve injectivity. Stimulation treatments included circulation to remove debris from the sand face, acid soak (18 hours) and circulation, and sodium hypochlorite soak and circulation, Both 10 percent and 32 percent inhibited hydrochloric acid solutions were used. Reported improvements in injectivity from stimulations were essentially nil.

Production

Oil production data are summarized in Tables 8 through 10 and in Figures 5 and 6. Monthly oil and water production rates are illustrated in Figure 5. Cumulative oil production for the total project and for the Farm A and Farm B portions of the project are plotted in Figure 6. Figure 6 also includes a plot of the total project water-oil ratio (WOR). At the time of project termination, the WOR was at a relatively stable level of from 30 to 35 barrels of water per barrel of oil. Oil producing rates had begun a slight decline at the time of project termination. A detailed listing of the oil production for the total project and for the Farm A and Farm B portions of the project is provided in Table 9. Total oil production amounted to 14,103 barrels. This amounted to about 5.15 percent of the oil-in-place (OIP) at the beginning of the test. Farm A resulted in a recovery of 4.4 percent of the OIP and Farm B resulted in a recovery of 6.04 percent of the OIP. Project oil displacement performance was quite poor. Total oil production was less than the quantity of oil injected into the project in the micellar fluid. The micellar fluid contained 28.7 volume percent of platformate charge (a refinery stream). This amounted to about 18,500 barrels of hydrocarbons injected into the project (excluding surfactants and alcohols). From a technical and economic viewpoint, the Lawry test was a failure.

Oil production data by individual producing well are summarized in Table 9. Oil production varied considerably from well to well with a minimum of 132 total barrels (H-91) and a maximum of 1,714 total barrels (H-102). There appeared to be the expected general correlation between oil production and water production. Generally more oil production occurred with increased water production (i.e., higher rates resulted in greater oil production).

Farm A oil production data are summarized in Table 10. These data summarize performance for the nine regular five-spot patterns in the project. The best well in the entire project (H-102) produced slightly over 9 percent of the OIP in this five-spot pattern. This well also produced polymer up to the 300 ppm level. There seemed to be no particular correlation with sulfonate and/or polymer production and oil production. For instance, Well H-103 produced sulfonate at levels of up to 7.7 percent of injected sulfonate concentration while total oil production amounted to 671 barrels. Well H-102 produced sulfonate at a level of up to about 1.0 percent while total oil production amounted to 1,714 barrels. Well H-107 showed a maximum sulfonate concentration of 6.3 percent of the injected sulfonate concentration and a total oil production of 346 barrels.[4]

Chemical production trends are summarized in Figures 7 through 11. Farm A data (regular five-spot patterns) are summarized in Figures 7 and 9. Farm B data are summarized in Figures 8 and 10. Sulfonate production data for the total project are summarized in Figure 11.

Early in the life of the project, water samples were collected from Separators A and B on June 7, 15, and 28, 1977. Analysis of these samples indicated average background concentrations of chloride to be 1,432 ppm and calcium to be 150 ppm. Injection of the 50,000 ppm sodium chloride (30,368 ppm chloride) solution was begun on May 20, 1977. Within six weeks of the beginning of brine injection, breakthrough of brine occurred at producing wells. Chloride curves in Figures 7 and 8 show that significant chloride production occurred before completion of chloride injection. This early breakthrough indicated a very poor sweep efficiency in both Farm A and Farm B. In Farm A, volumetric sweep appeared to be roughly 20 percent based upon the occurrence of the maximum in produced chloride concentrations. Similar performance was observed in Farm B. Produced chloride concentrations are plotted versus total volumes of water produced in Figures 9 and 10. Areas under the curves were determined. These data indicated that about 43.8 percent of the salt injected into Farm A was recovered and about 58.1 percent of the salt injected into Farm B was recovered. These data, combined, would indicate that about 52 percent of injected salt (total project) was recovered during the life of the project. From another viewpoint, these data indicated that approximately half the injected sodium chloride was lost during the life of the project. Since chloride is a non-absorbing tracer ion, and since its analysis is rather straightforward, these data raise the possibilities of injected fluids leaving the pilot area or being trapped within the pilot area.

Produced chloride and calcium data in Figures 7 and 8 also illustrate adverse ion exchange behavior in the pilot. Prior to initiation of the Lawry Project, ion exchange sites on the reservoir clays would have contained a sodium to calcium/magnesium ratio proportional to reservoir brine (0.0370 N sodium to 0.0074 N calcium plus 0.0024 N magnesium).[6,7] Injecting the preflush brine would change reservoir clay composition. The preflush brine sodium to calcium/magnesium ratio was much higher (0.8561 N sodium to 0.0022 N calcium plus 0.0012 N magnesium). Its effect would be to soften reservoir ion exchange sites. Calcium and magnesium would be released from clays into solution. Data plotted show that calcium concentrations in produced brines increased as chloride concentrations increased and slowly decreased as chloride decreased. It is expected that increased calcium concentrations would have had an adverse effect on sulfonate propagation.

Sulfonate and polymer propagation data are also summarized in Figures 7 and 8. Maximum sulfonate concentrations noted in produced aqueous fluids were less than one percent of the injected level. Polymer concentrations approached 32 percent of injected (Spike - 500 ppm). Data provided, although sparse, suggest that polymer propagated much better than did sulfonate in the Lawry Test. Insufficient data were provided to estimate polymer losses. No data were reported for the propagation of cosurfactants (Neodol, amyl alcohol or butyl alcohol). Since Neodol is a water soluble, anionic surfactant, it is possible that sulfonate analysis data include Neodol.

Figure 11 summarizes total sulfonate data[5] versus produced fluid volumes. Also included in the figure are oil-cut data. From this figure, sulfonate production appeared to precede oil response. Early sulfonate production in aqueous fluids is consistent with:

1) Poor oil recovery performance,
2) Adverse ion exchange behavior, and
3) Reservoir heterogeneity.

In order to estimate sulfonate loss, analysis data of sulfonate in produced oil are needed. However, a qualitative estimate of sulfonate losses can be prepared from data available. Integrating the area under the sulfonate curve in Figure 11 determined a qualitative estimate of sulfonate recovery to be less than one percent of injected chemical. These data suggested that essentially all sulfonate was lost to the reservoir.

Cumulative chemical production data over the period from June 1977 to January 1980 were provided in the final report. These data indicated that as of January 1980, about 3,710 barrels of micellar fluid had been produced. This represented about 5.8 percent of the injected surfactant. Again, these data indicated that most of the injected sulfonate was lost to the reservoir. These data also indicated that, as of January 1980, about 36,300 barrels of polymer had been produced. This represented about 18.6 percent of the injected polymer as of January 1980. Polymer injection continued until November 1980. Insufficient information was provided to estimate the total loss of polymer in the project. However, considerably more polymer than sulfonate was recovered throughout the life of the project.

<u>Evaluation Well</u>

Late in the project (April, 1980), it was decided to drill an evaluation well located 55 feet north of injection well H-84, between wells H-84 and H-110. The well was cored and logged. After initial logging, the well was completed with fiberglass casing which allowed additional induction logging to be performed after well completion.[5] Core recovery was 54.9 feet out of 55 feet of core cut.[5] Routine core analyses (permeability and oil saturation) were performed on recovered core material. In addition, core samples were analyzed for sulfonate content.

Results of these analyses indicated that oil saturations were significantly reduced in a three or four foot section of sand located near the top of the pay. Cores showing a reduction in oil saturation over waterflood saturations had permeabilities greater than 8.25 md.[5] Sulfonate retention was generally measurable only in the higher permeability sections (greater than 8.25 md).

These results, showing poor conformance, appeared to be consistent with earlier results in the project. In Phase I work, tracer surveys indicated that most injected fluids entered a thin, higher permeability zone of from four to eight feet in thickness toward the middle of the pay. In Phase II work, the injection-well logging program performed on nine injection wells indicated that most of the preflush brine entered a high permeability streak at the top of the pay. Produced brine concentrations showed rapid breakthrough of preflush brine. This is consistent with fluids contacting a relatively small portion of the reservoir. It follows that if injected fluids contacted a relatively small fraction of the pay, oil saturations would be reduced in these sections only, and chemical retention would be observed in these sections only.

EVALUATION

The Lawry Test failed technically and economically as an oil recovery project. Total oil recovered was about 5.15 percent of the estimated oil-in-place at the beginning of the project. The total barrels of oil recovered (14,103) amounted to less than the quantity of oil injected in the micellar fluid (18,500 platformate charge). This was in contrast to the earlier Bingham Test in the Bradford Third Sand. In the Bingham Test about 21 percent of the oil-in-place after waterflooding was recovered. The major difference in the two tests was the permeability variations between the two areas. This difference (82 md versus 7.65 md average K) was recognized as a major problem in the design stage. The purpose of the Lawry Test was to determine the feasibility of the process in a representative, low permeability portion of the reservoir. Results of the Lawry Test indicated that, at least for the fluid system tested, micellar/polymer flooding was not attractive in low permeability portions of the Bradford Third Sand.

A number of factors may have caused the failure of the test. Some of these will be discussed in an attempt to isolate the major reason or reasons causing project results. These factors are:

1) Operational Practice,
2) Conformance or Sweep Problems,
3) Injectivity Loss,
4) Inadequate Preflush,
   - salinity not optimum,
   - adverse ion exchange,
5) Inadequate Fluid Design,
6) Loss of Mobility Control, and
7) Adverse Chemical Loss.

Operational Practice

As noted throughout this report, operational practice in the Lawry Test was generally well designed and reasonable for reservoir conditions. Quality control of fluids appeared to have been well maintained. Adequate precautions were taken to protect fluids from corrosion. Mixing procedures were reasonable for the fluid systems. Biodegradation appeared to be controlled.

Fluids were injected near to or, perhaps, greater than parting pressure throughout much of the test. Data provided in the Appendix of Reference 5 (Table 10) indicated parting at wellhead pressures of as low as 568 psi to as high as 1,026 psi. Typically, the project was operated at average wellhead pressures of from 900 to 1,100 psi.[5] The adverse effects of this operational practice are difficult to assess. It is speculated that this practice did not result in significant loss of injected chemicals. It may have contributed to early breakthrough performance of sulfonate and polymer. If significant fractures were opened, fluids would have contacted less of the reservoir and/or could have been carried outside the pilot area. Since tracers were not included in micellar and polymer fluids, insufficient data are available to determine if injected fluids were driven out of the pilot area.

Conformance - Sweep Problems

As noted above, data from the evaluation well, injection well tracer surveys and injection well logging, and produced chloride data following preflush injection, all indicated poor volumetric sweep efficiency or poor injection well fluid conformance. These data indicated that only a small portion of the reservoir was contacted by injected fluids. If only four feet of pay (about 14 percent) were effectively contacted by injected fluids throughout the pilot area, the 14,103 barrels of oil recovered would represent about 35 percent of the OIP in this four foot zone. Although low, this recovery would be more encouraging. Poor conformance was a significant problem in the Lawry test. It is probable that heterogeneity was a reservoir characteristic that could not be significantly altered by operational practice.

Injectivity Loss

Significant injectivity losses occurred throughout polymer injection. As noted in Table 7, injectivities during preflush brine and micellar fluid injection, in Phase II operations, were comparable to those in Phase I. These injectivities were considered acceptable. Table 11 lists calculated estimates of the median frontal advance rate[8] in feet per day for various injection rates. Two estimates were prepared for each rate. The first estimate was calculated using an effective formation thickness of 29 feet and the second was calculated using an effective formation thickness of four feet. Depending upon the calculation, median rates varied from 0.04 to 1.55 feet per day. For typical injection rates of 20 to 40 barrels per day and a reservoir thickness of 29 feet, the median frontal advance rates varied from 0.07 to 0.14 feet per day. These rates are quite low. It is likely that these rates are too low for economic application of the process. However, if only a fraction of the reservoir were flooded (4 feet of pay, instead of 29 feet) rates would have varied from about 0.5 to about one foot per day. These higher rates would likely have allowed attractive economics if sufficient oil were present.

Core flood data in radial core tests were performed at a typical median frontal advance rate of 0.3 foot per day. Oil recovery performance data are summarized in Figure 3. Core floods performed in linear core tests studied the effects of flow rate on the oil recovery of Lawry test, micellar fluids.[9] As illustrated in Figure 12, fluids were shown to be very rate sensitive, i.e. generally decreasing oil displacement efficiency with decreasing flow rate. However, fluids tested showed a somewhat improved recovery at very low flow rates (0.1 feet per day). This is an unexpected tendency. The reported phase study data[9] suggested that Lawry fluids were lower phase fluids. As such, they would be expected to show immiscible displacement behavior, which would imply steadily decreasing oil displacement efficiency with decreasing flow rate. Final oil saturations reported in cores from the evaluation well, in swept zones, were in the range of from about 2 to about 30 percent pore volume. Four of the core plug samples indicated final oil saturations of less than 15 percent. This suggested that flow rates were adequate in the swept, near-well regions. Additional laboratory testing would confirm the effect of flow rate on the displacement efficiency of Lawry fluids.

Preflush

Core testing indicated the improved performance expected from preceding micellar fluid injection by a preflush of 50,000 ppm NaCl solution. The rather low average-sulfonate-equivalent-weight (calculated to be about 395) is consistent with the requirement of the 50,000 ppm NaCl preflush for optimum oil displacement. The effects of the presence of calcium in produced fluids were not reported in laboratory data. It is speculated that calcium levels, typical of Farm A produced waters, would adversely affect micellar fluid performance. In Farm A, calcium levels increased from about 140 ppm at the beginning of the project to about 500 ppm. Concurrent with 500 ppm calcium levels, chlorides were produced at about 30 percent of the injected level. This would imply that calcium levels could have been much higher in zones taking injected fluids, perhaps 1,100 ppm or greater. It is speculated that such a level of calcium would have formed calcium sulfonates and would have precipitated most of the injected sulfonate mixture. Water soluble, low equivalent weight fractions would have remained in solution. If precipitation occurred, sulfonate loss would be high. High sulfonate losses noted in the project are consistent with adverse ion exchange behavior. Early sulfonate breakthrough in aqueous fluids, as observed, is consistent with adverse ion exchange behavior.

It is also probable that high calcium concentrations would shift the optimum salinity level for best oil displacement performance. Additional data are needed to verify effects of adverse ion exchange behavior. Analyses of sulfonate and analyses of calcium in produced oils from Lawry would provide clues as to the tendency of calcium sulfonate formation. It is speculated that adverse ion exchange behavior resulting from the injection of the 50,000 ppm NaCl preflush was a major contributor to the failure of the project.

Fluid Design

Laboratory data were somewhat unsettling. Radial core test data suggested that fluid design was adequate. Linear core test data, although limited in number, suggest adverse rate sensitivity to a rate of 0.25 feet per day. At lower rates of 0.1 feet per day, an unexpected trend of improved oil recovery was noted. Data showing produced calcium levels from laboratory core tests were not available for comparison to project calcium levels. If laboratory calcium and magnesium levels were not typical of levels noted at Lawry, fluid design was likely inadequate. It should be noted that inclusion of Neodol in the fluid system would be expected to improve the calcium tolerance of the fluid system.

Optimum oil displacement did not occur at reservoir salinity/hardness conditions. Laboratory data indicated the requirement of a higher salinity brine ahead of the micellar slug for optimum oil displacement. Insufficient data are available to compare salinity levels in laboratory and Lawry produced fluids.

Mobility Control

Relative permeability data are not provided. However, radial core test data suggested that the mobility design was adequate. Precautions taken to protect the biopolymer appeared to be adequate. Produced polymer concentrations were reported to be at least 30 percent of injected polymer concentrations in Farm A fluids. Concentrations of up to about 60 percent of the injected level (500 ppm) were noted in fluids from Wells H-102 and H-110. As of January 1980, significant production (18.6 percent of that injected) of polymer was determined. There was no indication that significant biodegradation of polymer occurred. Significant mobility control loss did not occur. However, poor volumetric sweep was certainly noted.

Chemical Loss

Insufficient data were provided to assess the chemical loss of polymer, Neodol, butyl alcohol and amyl alcohol. Polymer did not appear to be adversely lost to the reservoir. As of January 1980, about 18.6 percent of injected polymer appeared to have been produced and polymer injection was continuing.

Sulfonate loss appeared severe. Maximum sulfonate concentrations reported in produced fluids were less than 10 percent of the injected concentration. The above, qualitative estimate of sulfonate loss indicated a loss of 99 percent of injected sulfonate. Loss estimated from January 1980 data indicated an approximate 94 percent loss of injected micellar fluid. With one exception, sulfonate loss in reduced oil saturation regions in cores from the evaluation well varied from 0.173 mg sulfonate per gram of rock to 1.140 mg sulfonate per gram of rock. Loss averaged 0.625 mg per gram of rock in the six core plugs analyzed. This loss was not particularly severe. However, core plug losses from the evaluation well do not appear consistent with produced fluid, sulfonate concentration levels. It is speculated that the apparent, severe sulfonate losses were the result of adverse ion exchange phenomena.

Chloride analyses of produced fluids indicated that about 50 percent of injected chloride was lost during the life of the project. Injected chloride would not be expected to show adsorption loss. Instead, loss would be expected by injected brine going out of the pilot area or by injected brine entering very low permeability sections and propagating at a slow rate compared to project life. The latter mechanism is thought to be in keeping with the heterogeneity of the Lawry test area.

Major Reasons for Project Failure

Three reasons are speculated to have caused the poor performance in the Lawry Test. These reasons are:

1) Reservoir Heterogeneity,
2) Adverse Ion Exchange Phenomena, and
3) High Sulfonate Loss.

Injected fluids (preflush brine, micellar and polymer) appeared to contact a small portion of the reservoir. Heterogeneity was such that only a few feet at the top of the pay had adequate permeability for fluids to flow. By contacting a small portion of the reservoir, limited oil mobilization was achieved.

Contact of reservoir clays by injected preflush brine served to soften ion exchange sites and resulted in increased calcium and magnesium ions in formation waters. These higher hardness levels would be expected to affect sulfonate adversely. Sulfonate would be expected to either precipitate or form oil soluble calcium and magnesium sulfonates. In either case, oil displacement efficiency would be reduced and sulfonate losses would be increased. This adverse ion exchange phenomena is thought to be the primary reason for the apparent, high sulfonate losses.

Aside from these reasons, another negative influence was also noted. Injection rates declined throughout polymer injection. These lower rates would result in poorer displacement efficiency in an immiscible displacement process such as micellar flooding. From a practical viewpoint, it is unlikely that the micellar polymer process is amenable to the low-permeability Bradford Third Sand reservoir because of the low injection rates experienced.

Comparison to the Bingham Test

Prior to the Lawry Test the micellar/polymer process was successfully tested in a more permeable portion of the Bradford Third Sand. This earlier test was referred to as the Bingham Test.[10] Properties of the pilot areas in the Bingham and Lawry tests are compared in Table 12. In February 1976, approximately 21 percent of the OIP were reported as recovered in the Bingham Test. Oil recovery was projected to be from 35 to 58 percent of the OIP when the project would be completed. Oil cuts in Farm A of the Bingham Test were as high as 19 percent. Farm B oil cuts peaked at 10.5 percent. These oil cuts are considerably higher than the maximum oil cut of 5 percent in Farm A of the Lawry Test. Permeability in the Bingham area was considerably higher (82 md average versus 7.65 md average). Porosity, which translates to barrels of oil available per acre foot of reservoir, was also much higher in the Bingham Test.

Both pilot areas were quite heterogeneous. A Dykstra-Parsons coefficient was calculated for both areas. The Bingham data (limited data available) resulted in a coefficient of 0.84 and Lawry data resulted in a coefficient of 0.88. These coefficients are interpreted as describing both pilot areas as having similar heterogeneity, although at considerably different absolute permeability levels. It is interesting to note that about 16 feet of the 23.7 feet of net pay appeared to have been processed by micellar fluids in the Bingham Test. A much smaller portion of the net pay appeared to have been processed in the Lawry Test. Although both areas were heterogeneous, the adverse combination of heterogeneity and low permeability level in the Lawry Test seemed to be much more detrimental to the process. Actual fluid performance data would suggest that Lawry was a more heterogeneous portion of the reservoir.

There was no evidence of adverse ion exchange phenomena occurring in the Bingham Test. Preflush brine was not used in the Bingham Test. A smaller slug of micellar fluid (5 percent pore volume versus 9.4 percent) was injected in the Bingham Test. Micellar compositions differed somewhat with the Bingham fluid containing about 47 volume percent petroleum distillate instead of the approximate 29 percent used in the Lawry Test. Polyacrylamide polymer was used at Bingham instead of the polysaccharide used at Lawry. From data reported, both polymers appeared to function effectively in their respective tests. Both polymers apparently resulted in injectivity reduction. However, injectivity losses at Bingham were not reported to be as severe. Unlike Lawry, injectivity was restored by stimulation treatments at Bingham. Severe losses of either sulfonate or polymer were not reported in the Bingham Test.

From data reported, the micellar polymer process appeared to be a viable oil recovery technique in the higher permeability portions of the Bradford Third Sand reservoir typical of the Bingham Test. The process did not appear to be viable in the lower permeability portions of the reservoir typical of the Lawry Test. A major problem in the Lawry Test was the low injectivities experienced. The apparent, more severe heterogeneity of the Lawry pilot area reduced the opportunity for successful micellar/polymer testing. Even though the more adverse chemistry of the Lawry area could likely be handled, the low flow capacity of the area does not appear amenable to the practical application of micellar/polymer flooding.

Project Improvement

At the time of project initiation, preconditioning a reservoir was considered a viable design alternative. Designing a micellar fluid system for the salinity/hardness environment of the Lawry is the primary suggestion for project improvement. In retrospect, a system functional at the reservoir salinity level (see Table 5) would alleviate much of the adverse ion exchange behavior caused by the high-salinity preflush brine. In addition, with optimum oil displacement occurring at this lower reservoir salinity level, injection of a high-salinity preflush would not be required. Such a design would likely require a higher average equivalent weight sulfonate product than was used.

From an evaluation standpoint, the inclusion of tracers in injected fluids (say the micellar slug) would have assisted the interpretation of fluid flow in the pilot area. It is probably not practical to trace 16 injection wells; however, tracers could readily have been included in the four central injection wells. By using a combination of chemical and radioactive tracers, both the micellar and spike polymer slugs could have been traced in these wells. A more complete geologic study would have provided a better basis for project diagnosis and evaluation.

Research Ideas

One of the means by which the process could be improved for Lawry and other low permeability reservoirs is the development or refinement of techniques to selectively stimulate the tighter portions of the pay.

This would enable fluids to be injected at a higher rate and sweep a larger amount of the reservoir rock. The difficulties with current techniques are that fractures are often difficult to confine within the pay and orientation cannot be controlled. There are numerous techniques for selective stimulation, but these have been only partially successful due mainly to the variations that exist in the strength and elasticity of rock. A need exists for reviewing and documenting the available techniques for creating controlled stimulation and making the information available to those involved in enhanced oil recovery. As necessary, additional research may be needed to develop improved techniques.

Other processes than chemical should be considered. The reservoir is probably too shallow for the application of carbon dioxide or enriched gas flooding. However, these processes could be screened for possible application. Saturations are probably too low for steam flooding. Perhaps wet combustion would be suitable, although the reservoir is rather shallow (1,280 feet).

LAWRY TEST

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TABLE 1

PENN GRADE MICELLAR DISPLACEMENT PROJECT

Reservoir Properties
24 Acre Lawry Test

Second Annual Report

Depth:	1,280 feet
Temperature:	64°F
Net Pay:	29 feet
Porosity:	12.65 percent
K:	7.6 md
S_o:	33 percent (core analysis); adjusted to 40 percent
Crude Viscosity:	5 cps
Pore Volume:	684,577 barrels
Area:	24 acres

Fourth Annual Report

	Farm A	Farm B
Pore Volume:	388,617 bbls.	295,960 bbls.
S_o:	40%	40%
Oil-in-Place: (OIP)	155,447 bbls.	118,384 bbls.

TABLE 2

PHASE I - LAWRY TEST, WELL H-68 FLUID INJECTION SUMMARY

Date	Fluid	Total Fluid Injected, Bbls	Cumulative Injected, Bbls
10/75	Water	3,415	3,415
10/75	Micellar	452	3,867
02/76	Polymer	2,867	6,734
06/76	Water	3,650	10,384

TABLE 3

PHASE I - LAWRY TEST
MICELLAR SLUG COMPOSITION*

Component	Volume Percent
Witco TRS-16**	5.46
Witco TRS-40**	5.51
Diesel	17.97
Amyl Alcohol	2.37
Butyl Alcohol	0.66
Water	68.03

* Specific gravity 0.972 @ 64°F.
** Petroleum Sulfonate

TABLE 4

LAWRY TEST MICELLAR FLUID COMPOSITION

Component	Weight Percent	Volume Percent	*Average Equivalent Weight
Witco TRS-16	4.66	4.20	420
Witco TRS-40	6.40	5.12	340
Platformer Charge	21.58	28.67	-
Lawry Supply Water	67.36	62.01	-

* Witco petroleum sulfonate, product information data.

TABLE 5

LAWRY TEST
WATER ANALYSES

First Annual Report

Injection Water:	Lawry WSW #5
Na	15 ppm
Ca	43 ppm
Mg	14 ppm
Cl	31 ppm
SO_4	0.1 ppm
TDS	258 ppm

Second Annual Report

Produced Water:

	Farm A	Farm B
Na	925	804
Ca	144	152
Mg	24	34
Cl	1575	1375
SO_4	5	3
TDS	2950	2580

TABLE 6

PHASE II - LAWRY TEST
FLUID INJECTION VOLUMES

Fluid	Planned Injection		Actual Injection	
	Bbls	% PV	Bbls	% PV
Preflush Brine	68,459	10	113,908	16.6
Clean Out Water	-	-	1,079	-
Micellar Fluid	61,613	9	64,394	9.4
Polymer				
Spike-500 ppm	68,458	10	105,148	15.3
Body -350 ppm	349,134	51	*174,806	25.5
Tail -100 ppm	205,373	30	* None	-
				66.8

* Test terminated.

TABLE 7

INJECTION RATE COMPARISON
LAWRY TEST

Fluid	*Phase I: Well H-68 Bbls/day	**Phase II: Average Bbls/day
Preflush Brine	40	61
Micellar Fluid	20	22
Polymer		
10 cps	28	-
7 cps	35	-
9 cps	-	19
5.5 cps	-	15

* Single well test.
** Average based upon the total project (16 injection wells).

TABLE 8

OIL RECOVERY - LAWRY TEST*

	Total Fluid Injected, Bbls	Project Oil-In-Place (OIP), Bbls	Pore Volume (PV) Bbls	Oil Recovery		
				Bbls	% PV	% OIP***
Total Project	**459,889	273,831	684,577	14,103	2.06	5.15
Farm A	241,049	155,447	388,617	6,954	1.79	4.47
Farm B	218,840	118,384	295,960	7,149	2.42	6.04

* Data as of November 20, 1980, reported in the Final Report.
** This total is in slight disagreement with a total determined from data presented in Table 6 (459,335 Bbls).
*** OIP - Oil-in-place after waterflooding.

TABLE 9

LAWRY TEST
TOTAL OIL PRODUCTION SUMMARY

Well	Cumulative Bbls, Water	Cumulative Bbls, Oil
Total Project	598,339	14,103
Farm A	227,545	6,954
Farm B	370,794	7,149
H-90	18,564	137
H-91	17,353	132
H-92	19,478	165
H-93	9,726	135
H-94	16,143	412
H-95	18,482	207
H-96	15,956	278
H-97	21,935	778
H-98	19,032	693
H-99	27,255	502
H-100	17,820	240
H-101	29,489	540
H-102	27,430	1,714
H-103	17,806	671
H-104	31,220	820
H-105	23,836	470
H-106	40,383	713
H-107	24,273	346
H-108	26,941	676
H-109	21,108	344
H-110	31,005	1,088
H-111	25,557	580
H-112	28,595	756
H-113	36,762	855
H-114	32,141	853

TABLE 10

LAWRY TEST - FARM A
REGULAR FIVE-SPOT OIL PRODUCTION

Center Producer	OIP Bbls	Bbls PV	Total Bbls Oil Produced (11/20/80)	Total Injected Bbls Assigned To Producer (11/20/80)
H-94	17,925	44,812	412	22,298
H-97	17,044	42,611	778	24,887
H-98	17,637	44,093	693	20,537
H-101	18,736	46,839	540	32,764
H-102	18,284	45,709	1,714	21,650
H-103	15,484	38,709	671	28,887
H-106	17,659	44,147	713	32,576
H-107	15,641	39,103	346	26,427
H-110	17,684	44,210	1,088	31,024
		*390,233	6,955	241,050

Percent Pore Volume Injected = 61.8

Percent Pore Volume Oil Recovered:

Farm A = 4.47 % OIP
Well H-102 = 9.37 % OIP
Well H-107 = 2.21 % OIP

* This volume is reported as being 388,617 bbls in numerous tables.

TABLE 11

LAWRY TEST

ESTIMATED MEDIAN FRONTAL VELOCITIES (V_f)*

Area: 1.5 acres
Porosity: 12.65

q, Bbls/day	h, feet	V_f, ft/day
60	29	0.21
	4	1.55
40	29	0.14
	4	1.03
30	29	0.11
	4	0.77
20	29	0.07
	4	0.52
10	29	0.04
	4	0.26

* Estimated after, Parsons, R. W., "Velocities in Developed Five-Spot Patterns", JPT, May, 1974, p.550.

TABLE 12

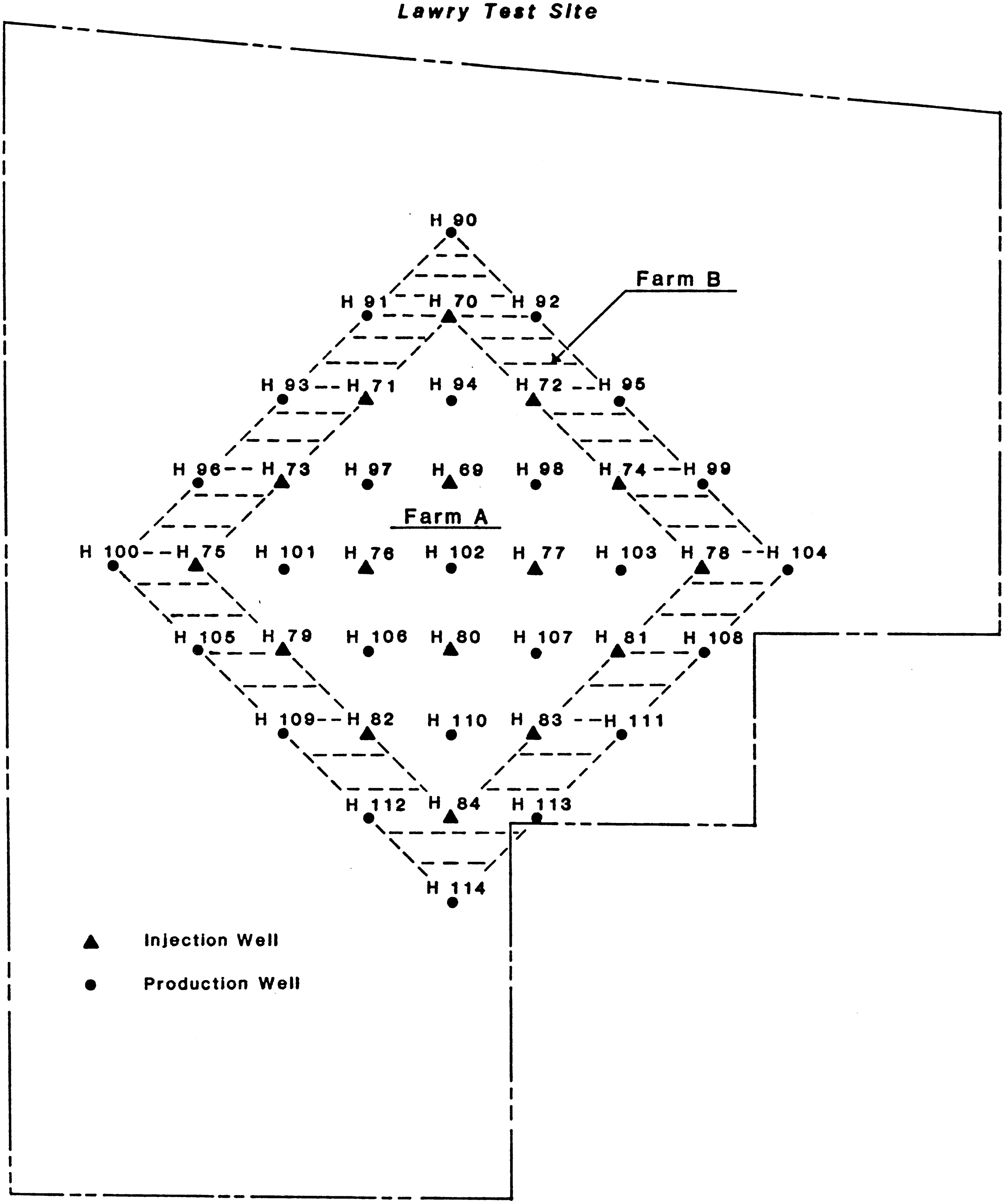
BRADFORD THIRD SAND MICELLAR TESTS

Characteristic	Bingham Test	Lawry Test
Reservoir	Bradford Third Sand	Bradford Third Sand
Depth, feet	1,866	1,280
Net feet of pay	23.7	29.0
Pilot size, acres	46.5	24
Pore Volume, bbls	1,531,000	684,577
Dykstra-Parsons Coefficient*	0.84	0.88
Average Porosity, percent	18	12.65
Permeability, md:		
Average	82	7.65
Maximum	311	60
Minimum	8.4	0.5
Capacity (Kh), md ft	2,207	222
Oil Saturation, percent:		
Average (official)	40	40
Range	36 to 43	-
Reservoir Temperature	68	64
Oil Viscosity, cps	5	5
Preflush Brine, percent P.V.	0	16.6
Micellar Slug Size, percent PV	5.3	9.4
Mobility Buffer:		
Type	Polyacrylamide	Polysaccharide
Size, percent PV	100 (tapered concentration)	41.0 (test terminated)
Cumulative Oil Recovered:		
Barrels Total	130,000	14,224
Percent OIP	21.2	5.2

* 11 percent porosity cutoff - Limited data available for the Bingham Test (22 data points)

Figure 1*

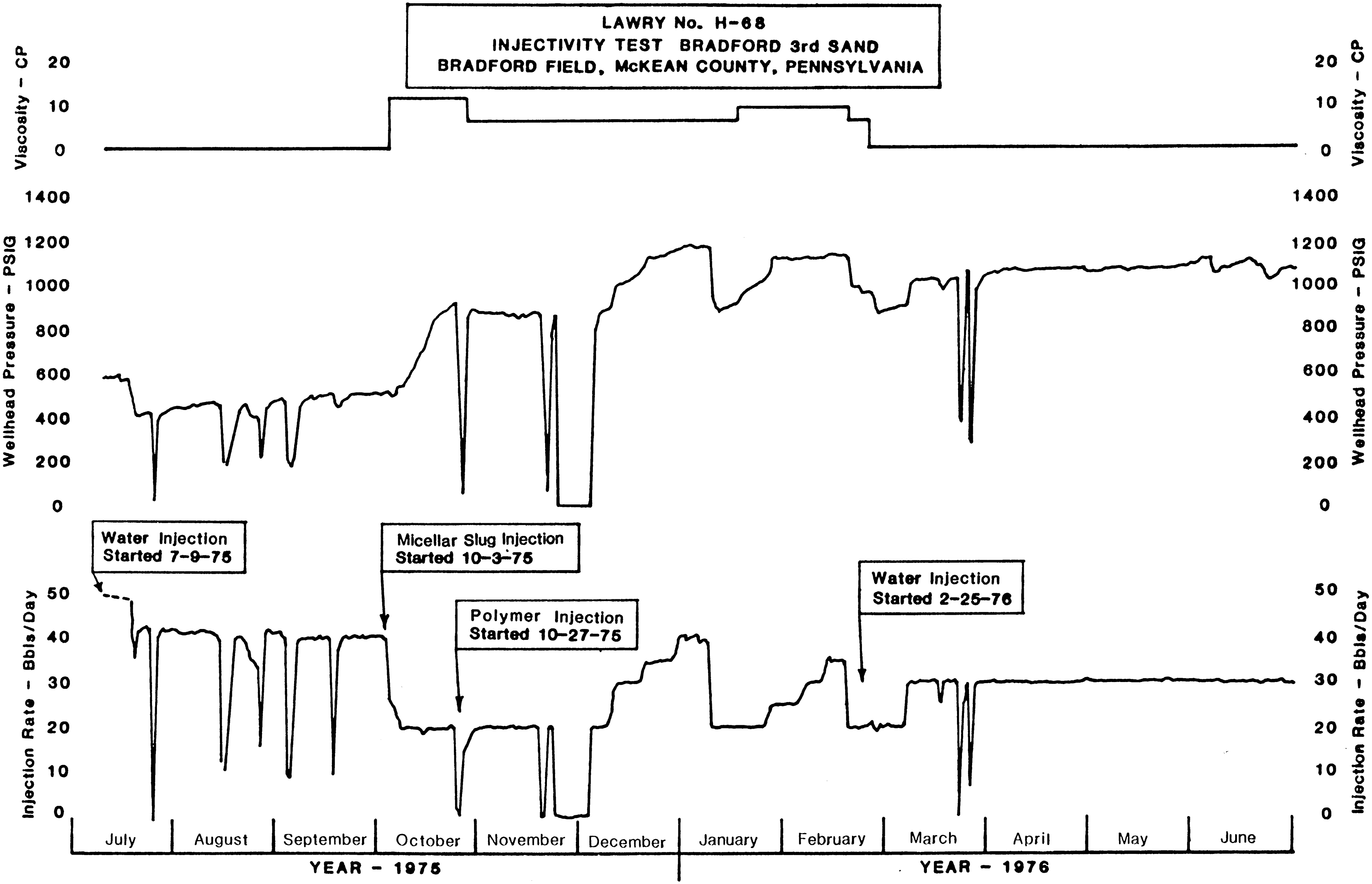
Lawry Test Site



* From Reference 2

Figure 2*

Fluid Injection Summary—Phase 1



*From Reference 2

Figure 3
Field Mixed Slug
Lawry Test

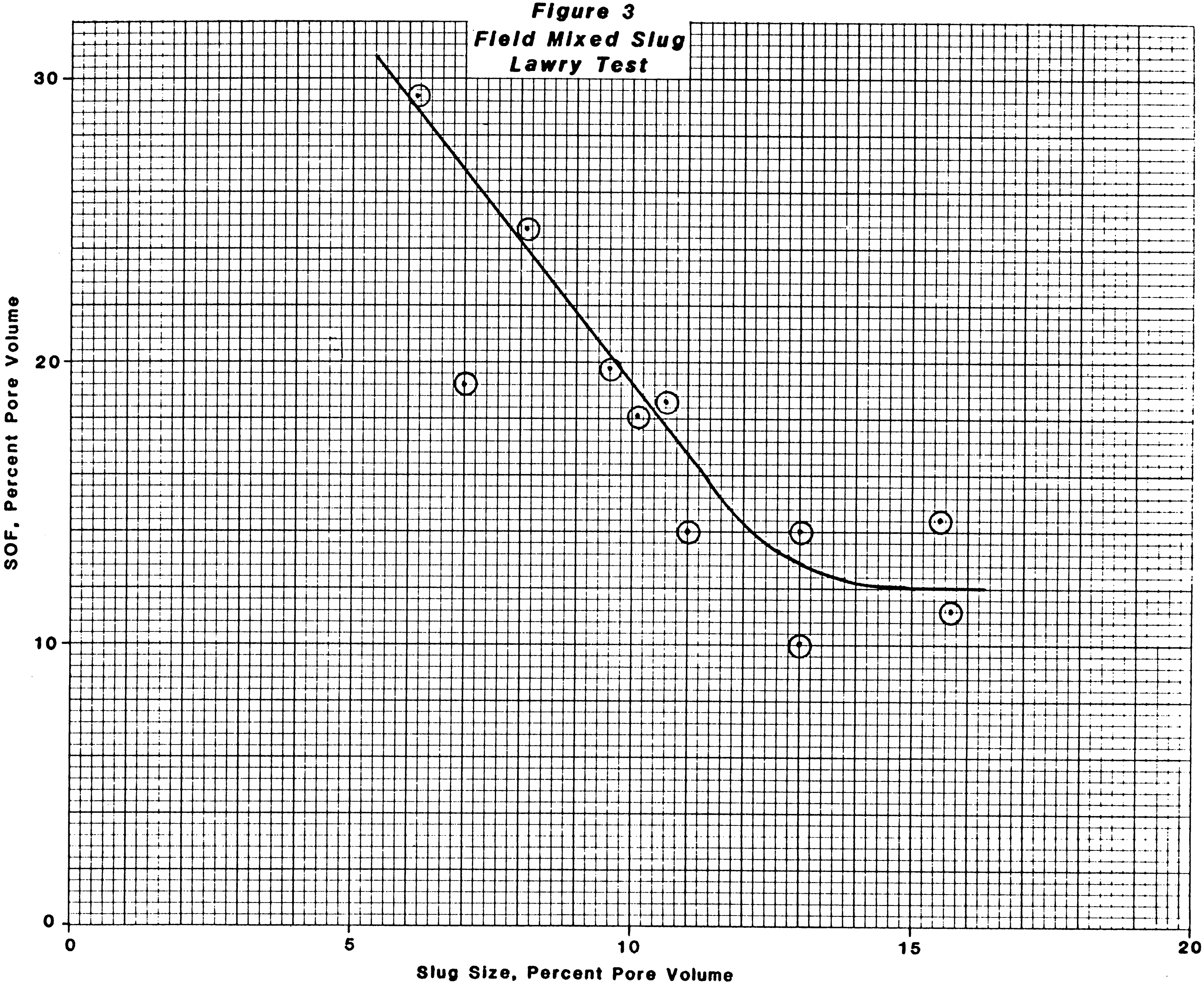
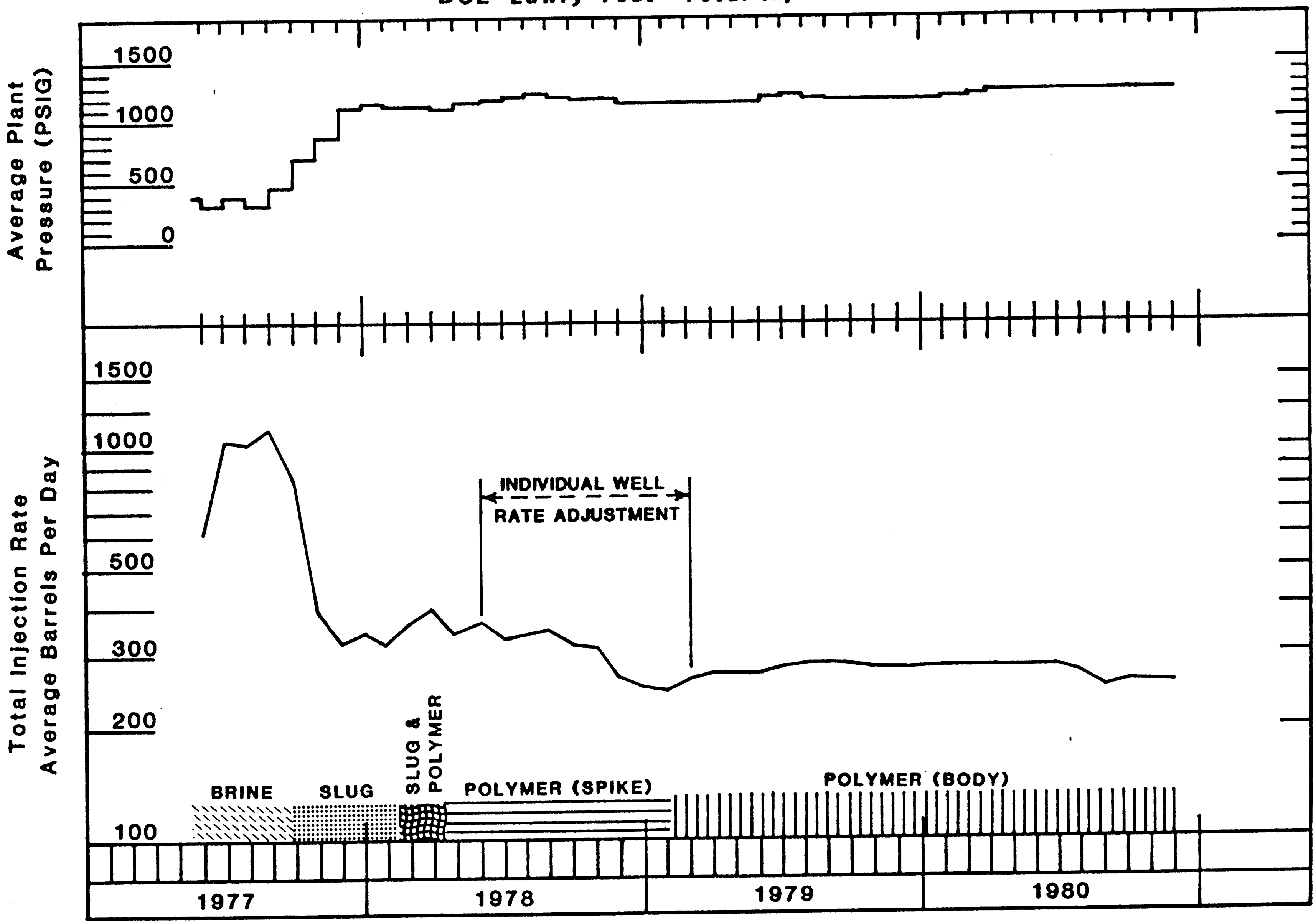


*Figure 4**

DOE -Lawry Test—Total Injection



*From Reference 5

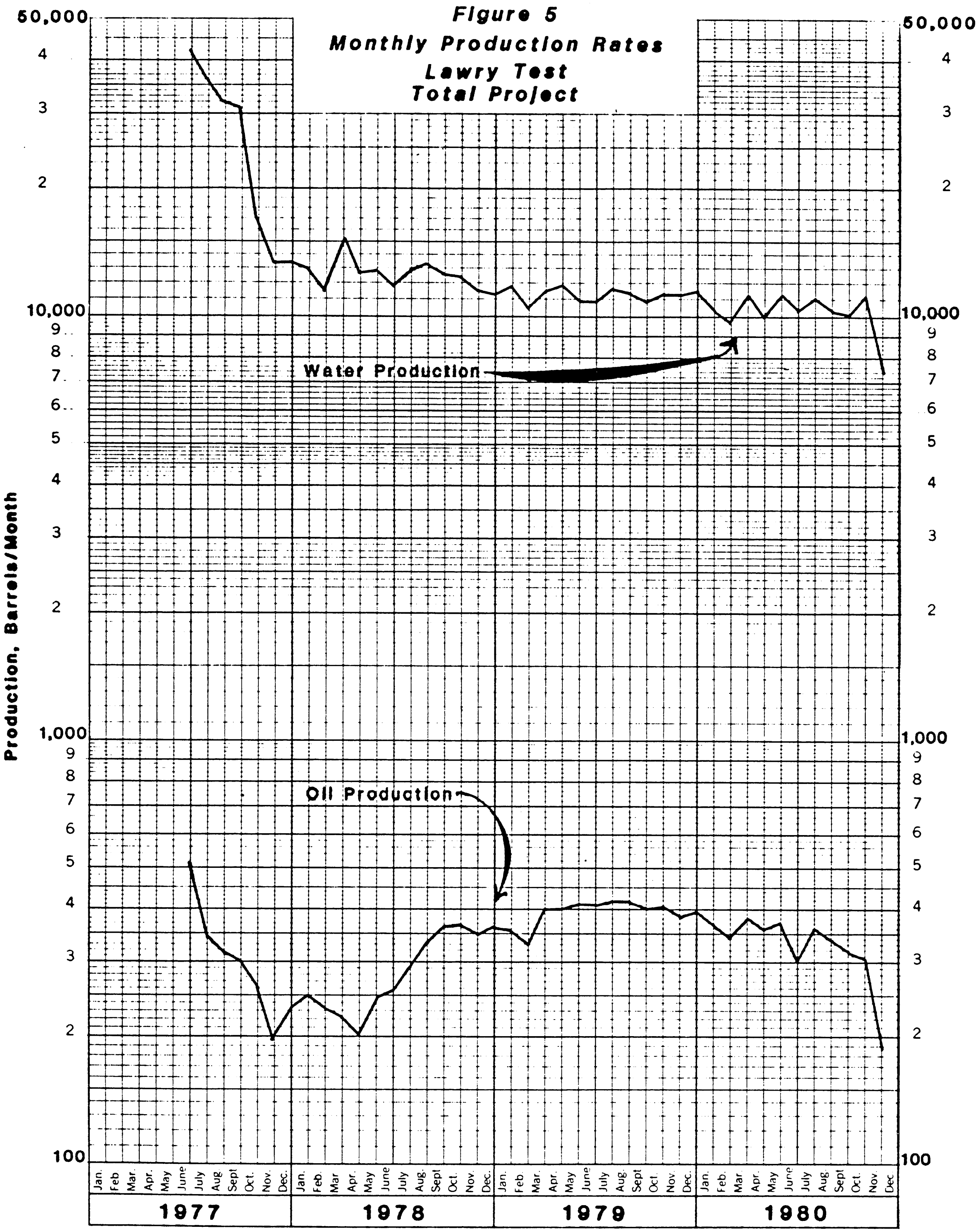


Figure 5
Monthly Production Rates
Lawry Test
Total Project
Production, Barrels/Month
50,000
10,000
1,000
100
Water Production
Oil Production
Jan. Feb Mar. Apr. May June July Aug Sept Oct. Nov. Dec.
1977
1978
1979
1980

Figure 6

Lawry Test

Bradford Micellar - Polymer Flood

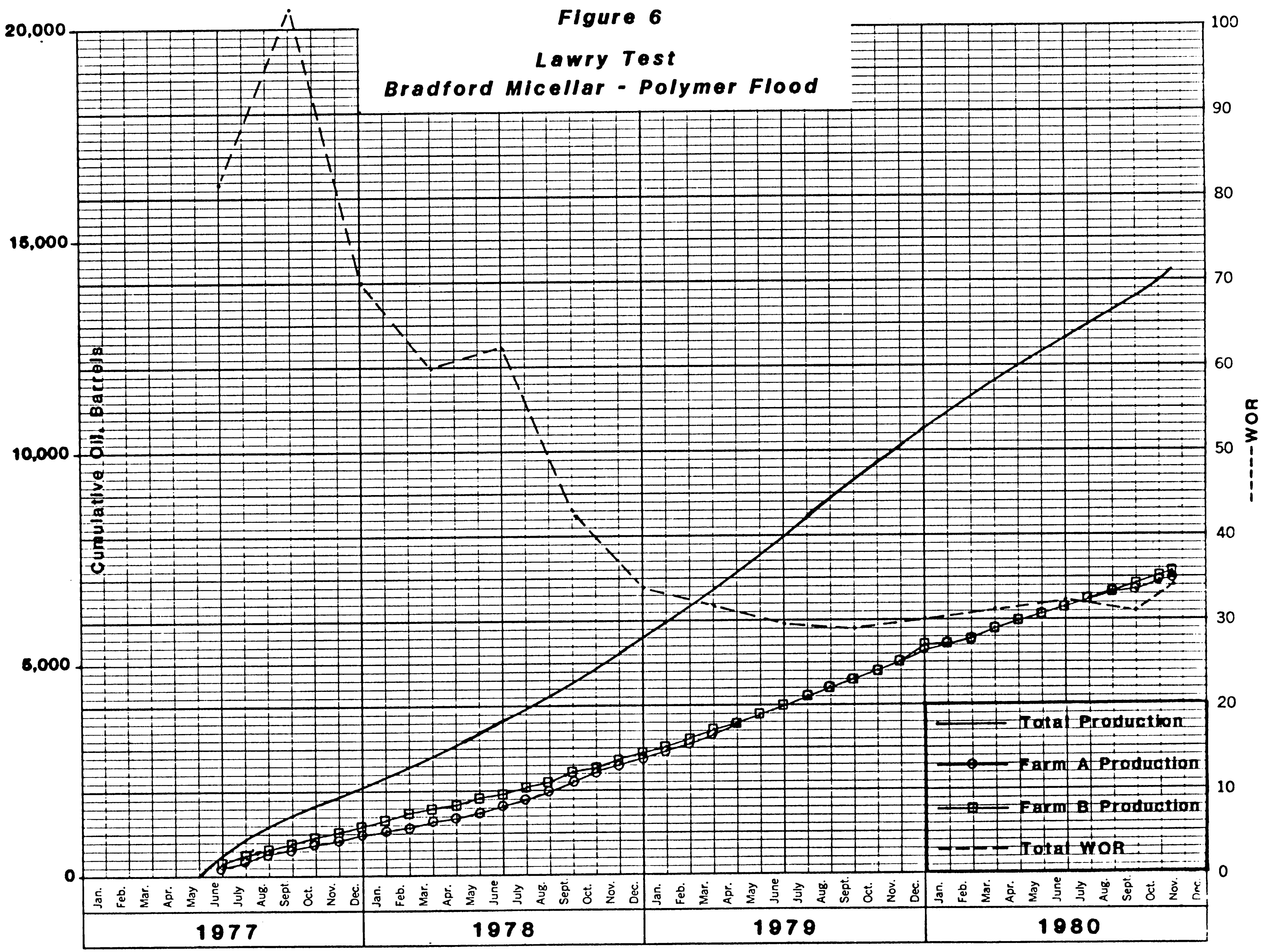


Figure 8

Lawry Farm B - Chemical Production

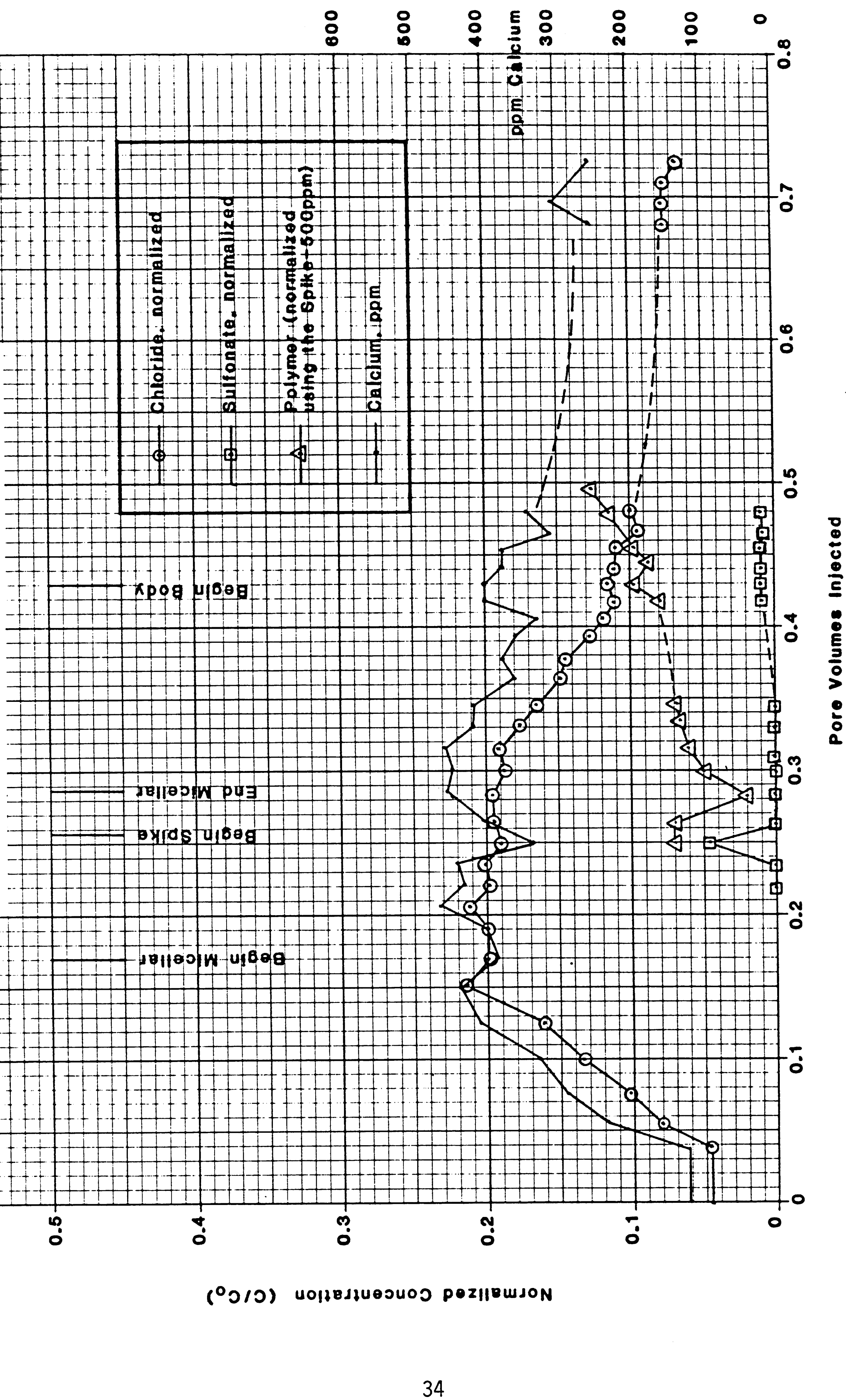


Figure 9

Lawry Farm A - Produced Chloride

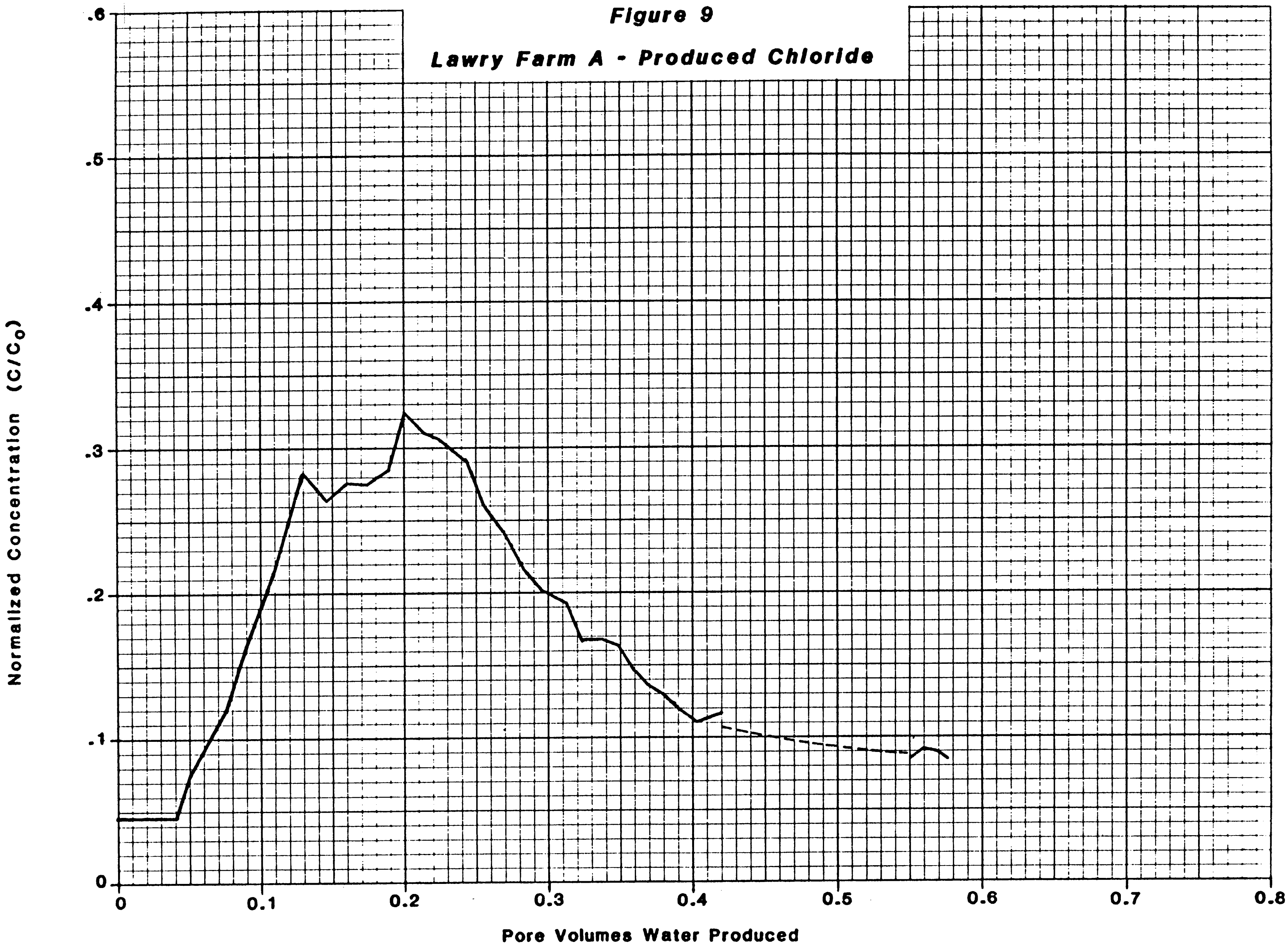


Figure 10

Lawry Farm B - Produced Chloride

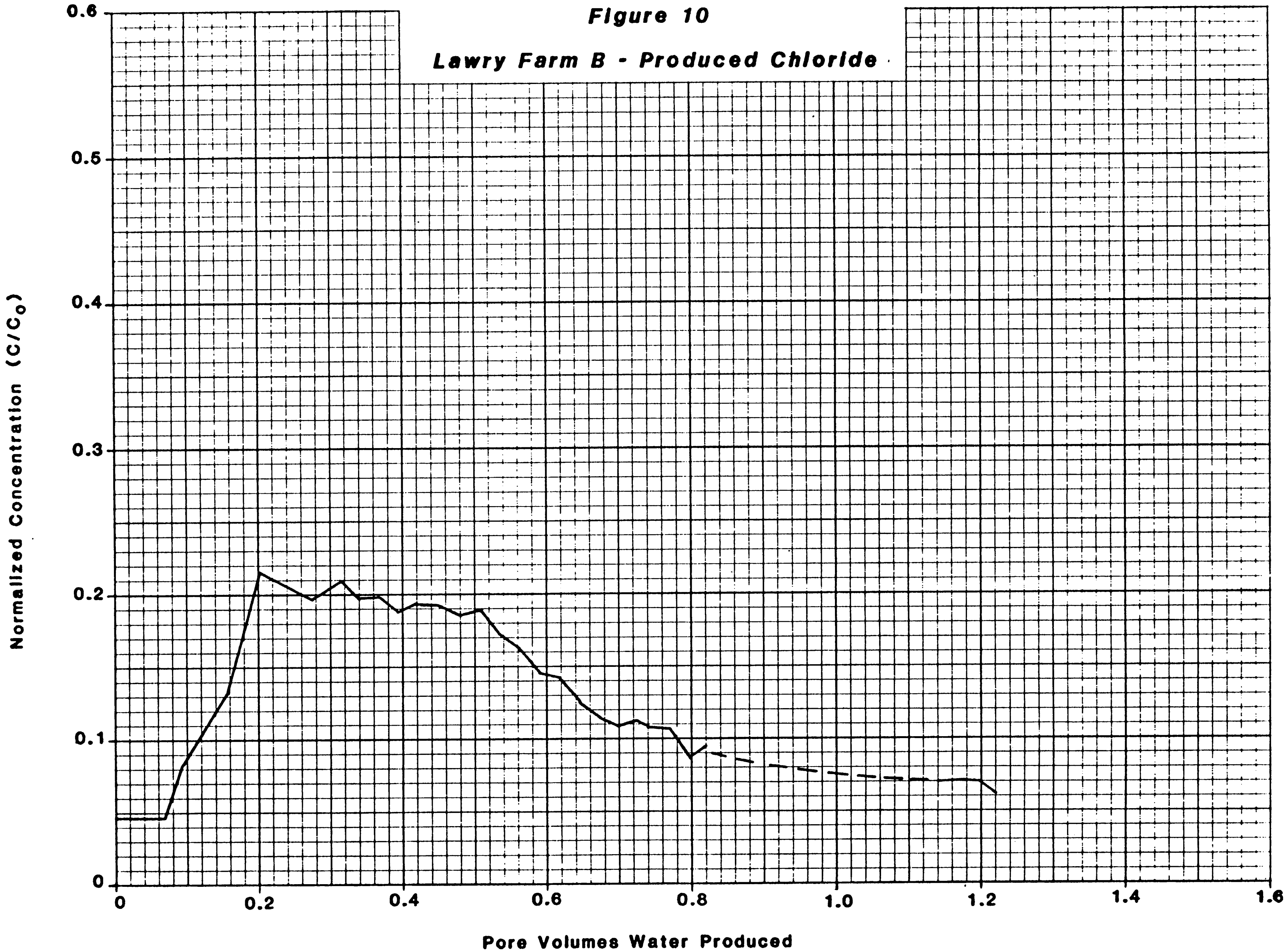


Figure 11

Lawry Test
Total Production

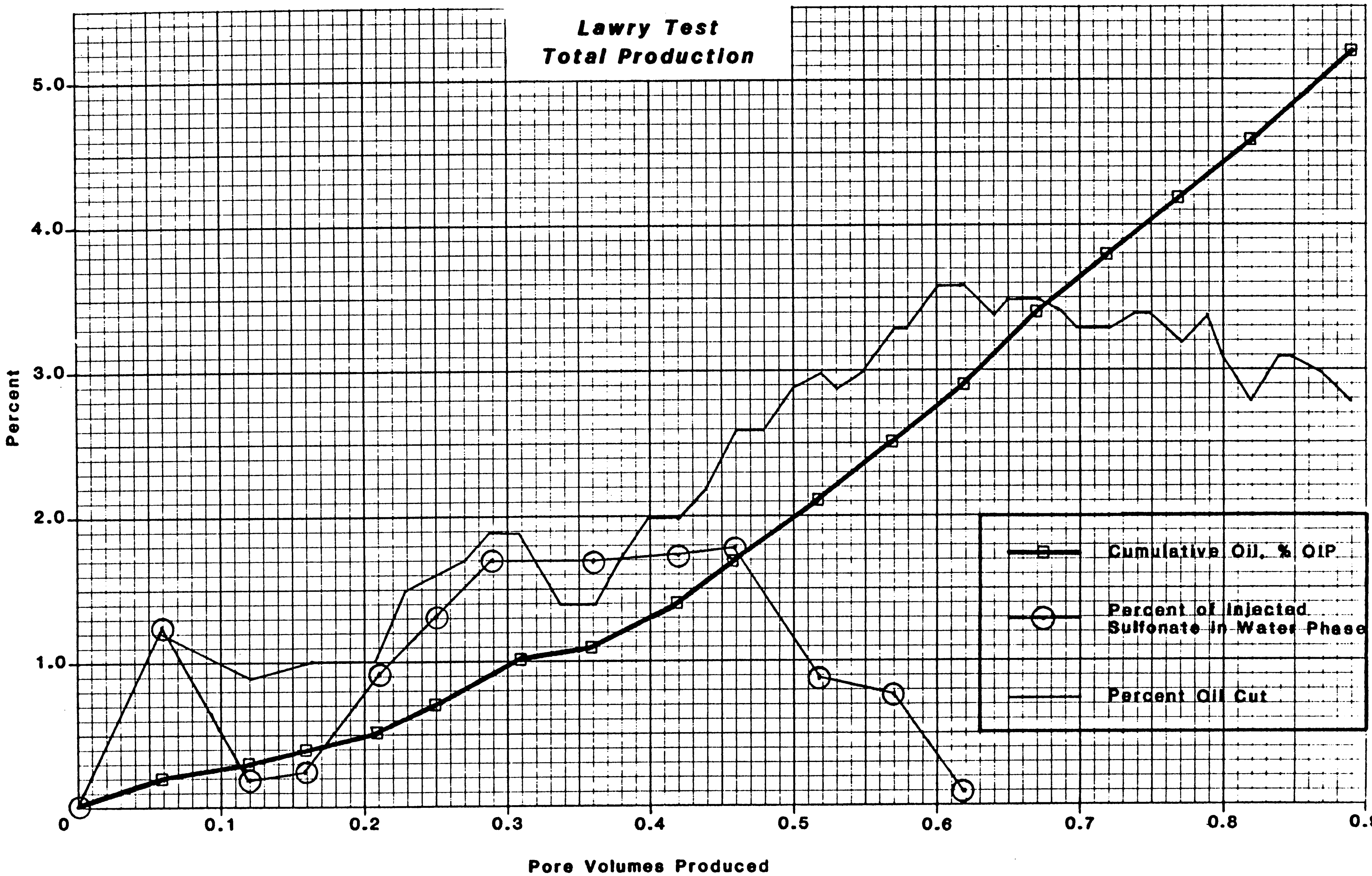
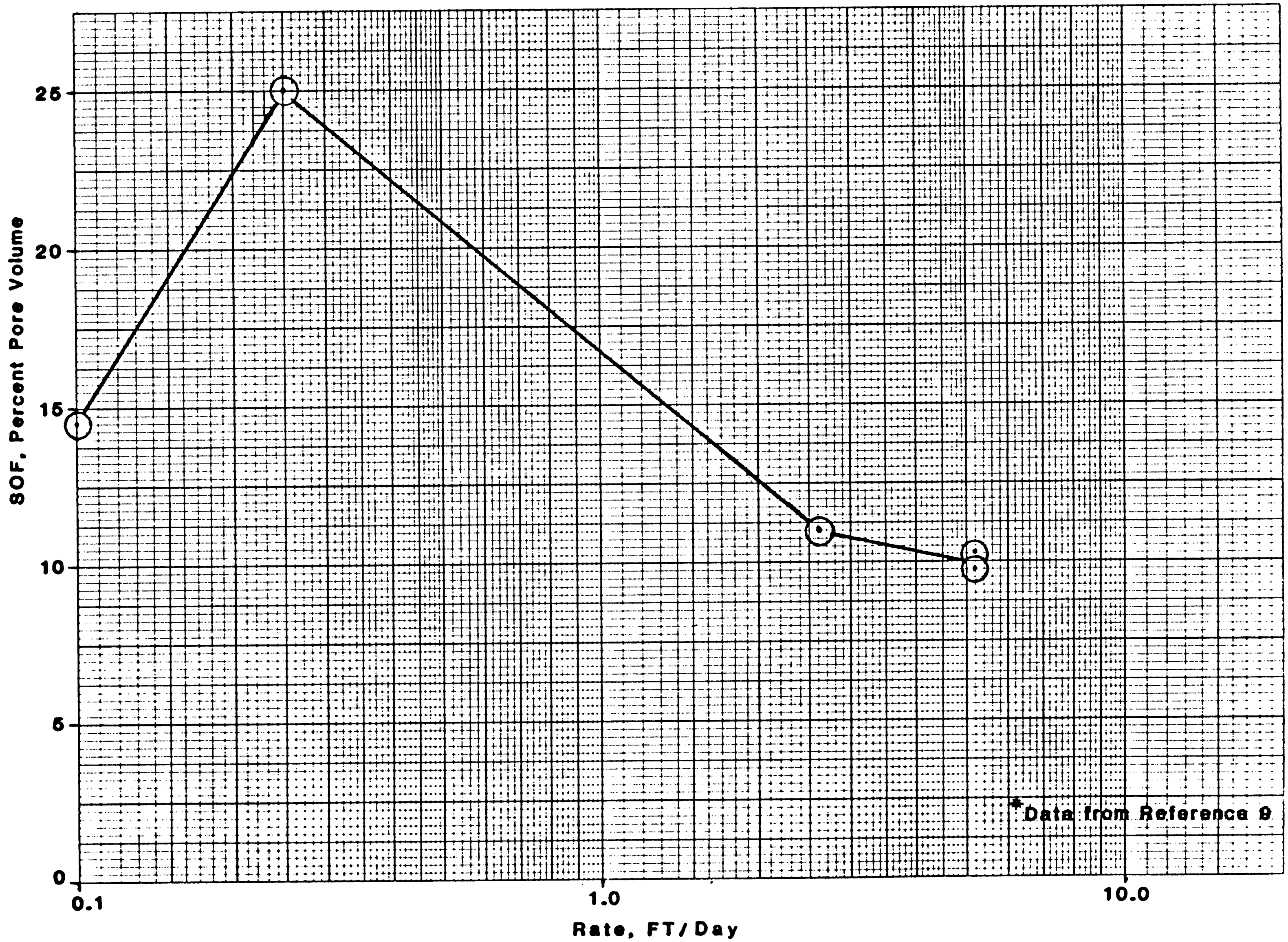


Figure 12*

Lawry Test Fluids

10% P. V. Slugs



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