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PENN GRADE MICELLAR DISPLACEMENT PROJECT
FIRST ANNUAL REPORT, JUNE 1975—JUNE 1976

By

Pennzoil Company
Prepared for DOE Under
Contract No. E(46-1)-8002

Date Published—March 1978

Bartlesville Energy Research Center
U.S. Department of Energy
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FIRST ANNUAL REPORT, JUNE 1975—JUNE 1976

By

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PENN GRADE MICELLAR DISPLACEMENT PROJECT
YEAR ENDING JUNE 30, 1976

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FIRST ANNUAL REPORT
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SUMMARY

The main objective of the Penn Grade-ERDA Micellar Displacement Project is to assess and hopefully, demonstrate the feasibility of commercial application of the micellar-polymer process for tertiary oil recovery from a rather large, but relatively "tight" section of the Bradford Third Sand. The initial phase of this project involves pertinent core and field injectivity measurements from a freshly drilled well, as a basis for assessing the feasibility of a small demonstration test flood to be performed under Phase II.

This report details the work done and results obtained under Phase I (Injectivity Test) completed during the first year of the project. These results, having indicated that the pattern test envisaged under Phase II is indeed feasible, work is now in progress to carry the project to the pattern test phase, in pursuit of project goals.

INTRODUCTION

Penn Grade/ERDA Contract

The Penn Grade Micellar Displacement Project is a tertiary oil recovery test of the micellar-polymer process in the Bradford Field. The test is conducted under the auspices of the Pennsylvania Grade Crude Oil Association with the financial participation of the United States Energy Research and Development Administration (ERDA), Pennzoil Company, Witco Chemical Corporation, and

Quaker State Oil Refining Corporation. The test, locally referred to as the Lawry Project, is funded by ERDA Contract No. E-(46-1)-8002, which was awarded to the Pennsylvania Grade Crude Oil Association on June 30, 1975, in the amount of \$4,444,000. This is a cost-sharing contract of 5-year duration with 50 percent government funding amounting to a total of \$2,222,000. Pennzoil, Witco, and Quaker State will equally share the remaining 50 percent of the funding with Pennzoil designated as operator for the performance of the test.

The test will employ the Marafloodtm process with the Marathon Oil Company providing technical services under sub-contract. The objective of the Lawry Project is to demonstrate the efficiency and economics of using the Marafloodtm process to recover tertiary oil from a relatively tight, but major portion of the previously waterflooded Third Sand in the Bradford Field.

The Penn Grade Micellar Displacement Project is to be conducted in two parts. Phase I consists of a single injection well to determine the injectivity characteristics of Marafloodtm process fluids in the low permeability Bradford Third Sand reservoir. Phase II would provide for the development of a 24-acre pattern test, consisting of nine enclosed 5-spots on one and one-half acre spacing, should acceptable injection rates be achieved during Phase I. Phase I will cover a one-year period and Phase II will cover a four-year period. A major decision point for performance evaluation will occur during Phase II at the point when the aggregate volume of the micellar slug and polymer solution injected into the test sand is approximately 50% of the pore volume of the pattern.

Field and Site Selection

The test site is on the Lawry Farm, Foster Township, McKean County, Pennsylvania. (Figure 1) The Lawry lease is located in the heart of the Bradford Field and

represents sand conditions typical of over 50 percent of the Bradford Field reservoir. The results of a successful test will allow the commercial exploitation of substantial lease acreage owned by various companies and independent operators in the general area of the test site.

Oil production from the Bradford Field was established in 1871. The field has grown to approximately 85,000 acres and has produced an estimated 660 million barrels of oil. Controlled waterflooding was started in 1926 and has accounted for more than 60 percent of the total production. (Figure 2)

The 98-acre Lawry lease has been successfully waterflooded as has most of the Bradford Field. Operations were initiated on the lease in 1929 and terminated in 1964, with waterflood recovery at approximately 9,000 barrels of oil per acre. Stripper production has been maintained to present.

The Bradford Third Sand is the main pay horizon in the Bradford Field. It is a member of the Chemung formation (Upper Devonian Age) and is a hard, brown, fine-grained sand. The oil accumulation is due apparently, to permeability-porosity traps, with several pools existing within the producing limits of the Bradford Field.

On the Lawry lease the Bradford Third Sand occurs at a depth of about 1,300 feet. The producing interval is approximately 100 feet thick with sand and shale members. The top 50 feet contain the bulk of the effective sand. Core data (Table 1) from Well H-88, located on the east side of the project site, shows an average permeability of 9.6 millidarcys and an average porosity of 14.4 percent. The oil has a viscosity at reservoir conditions of approximately 4 centipoise and is a sweet 44⁰ API gravity crude. The sand is classically

oil wet and the reservoir is characterized by relatively uniform permeability. Localized fracturing is present in the reservoir and conforms to the depositional trend which is northeast-southwest.

Penn Grade oil fields produce a very desirable crude oil which is used as a prime feed source for the refining of a major portion of United States lubricating oils. These fields had an estimated 12 billion barrels of high-quality crude oil in place and have long been subjected to secondary recovery techniques. The very survival of the industry is now dependent upon the commercial development of adequate tertiary recovery processes. This test is designed to investigate the use of micellar solutions as tertiary recovery agents in the low permeability sections of the Bradford Third Sand. Interest is centered on these sections because most of the in-place Pennsylvania Grade crude oil is located in such low permeability sands. Many different tertiary oil recovery methods have been attempted in the Bradford Field with limited success. A recent project has demonstrated the technical feasibility of tertiary recovery by micellar-polymer flooding in a more permeable part of the Bradford Third Sand in the Bingham lease. (See Appendix A)

Pattern Selection

The injectivity study was made on a single injection well (Phase I of the Lawry test) located on the boundary of the lease, north of the site proposed for the main test (Phase II).

The main Lawry test will contain forty-one development wells drilled as regular one and one-half acre five-spot patterns. The 24-acre test will contain nine enclosed five-spots within a 13.5-acre square surrounded by sixteen producing wells. The 24-acre project will be oriented 45 degrees off north to minimize the effects of the existing fracture system which is thought to be present in the Bradford Field. The oriented five-spot pattern will conform with the

original two-acre five-spot pattern employed in the secondary development of this lease and will be positioned to avoid "old well" overlap as much as possible. All "old wells" will be plugged and abandoned, and new wells will be drilled for this test. The proposed test pattern is shown on Figure 3.

The one and one-half acre five-spot spacing will permit evaluation and appraisal for commercial application in a reasonable period as specified in the ERDA contract. The spacing will also provide maximum reservoir data for process control while maintaining development and chemical investments at a reasonable level.

PHASE I - INJECTIVITY TEST

Objectives

The objectives of Phase I of the Lawry Project are as follows:

- 1) Obtain a 6-inch diameter core of the Bradford Third Sand for micellar-polymer lab work.
- 2) Determine the injectivity characteristics of Marafloodtm process fluids in the low permeability Bradford Third Sand reservoir.
- 3) Evaluate the feasibility of proceeding with a pattern test, Phase II, to evaluate the commercial application of a micellar-polymer process for tertiary oil recovery from low permeability sands.

The main consideration of Phase I will be whether or not the injection rates in the tight Bradford Third Sand formation will be sufficient for commercial operation.

Well H0-68

Drilling

Well H0-67 was spudded on December 18, 1974, and an 8-inch hole was drilled with cable tools to a depth of 1,075 feet, the core point. A conductor (12 inches in diameter) was set at 20 feet, and 414 feet of 8-5/8 inch casing was set to protect the fresh water-bearing strata at this location. While running in the core tools preparatory to cutting a 6-inch diamond core, the core barrel, 178 feet of 5-inch O.D. drill collars, and 29 feet of 3-1/2 inch drill pipe were dropped in the hole. The fishing job was unsuccessful and the hole was abandoned in favor of a new location (H0-68) 25 feet north of H0-67.

Well H0-68 was spudded on February 13, 1975 and an 8-inch diameter hole was drilled with cable tools to the core point of 1,075 feet. A conductor (12 inches in diameter) was set at a depth of 70 feet and 415 feet of 8-5/8 inch casing was set to protect the fresh water-bearing strata. The Bradford Third Sand was cored using a 7-3/4 inch by 6 inch rotary diamond corehead. The Driller's Log is shown in Table 2.

Core Program

The Bradford Third Sand interval 1,075 feet to 1,123 feet was rotary cored with a 7-3/4 inch by 6 inch diamond corehead using a saline drilling fluid with a sodium chloride concentration of 10,000 to 20,000 ppm. A 10-foot core barrel was used and a total of five cuts were made. Core recovery was 45.9 feet out of 48 feet.

The core was removed from the barrel, wiped clean, measured and described, and placed in 3-foot plastic containers filled with Lawry lease crude oil. The core interval 1,082.55 feet to 1,120.91 feet was shipped to Marathon's Denver Research Center for evaluation and specialized fluid displacement tests.

Seven samples of the core were taken and analyzed by the John DePetro Laboratory of Bradford, Pennsylvania. The average porosity as determined by the fluid saturation method was 14.5 percent. The air permeability was 19.3 millidarcys, and the oil saturation was 32.8 percent. The core description is shown on Table 3 and the core analysis is shown on Table 4.

Log Program

The logging program for Well H0-68 consisted of electrical and radioactive surveys run to determine reservoir parameters and assist in the completion of the well. Table 5 is a summary of all the logs run on Well H0-68, and the logs are shown on Figures 4 and 5.

Data from the first five logs in Table 5 was analyzed by standard log calculation methods with the aid of a computer to produce a computer processed, "Com-Pro-Log" (Figure 6).

The tabulated reservoir properties analyzed on a foot-by-foot basis for the Bradford Third Sand interval 1,070 feet to 1,126 feet are shown on Table 6.

The CDI Inclinator survey indicates the location of the bottom of the hole relative to the top of the hole. The survey which was run on Well H0-68 is tabulated in Table 7 and illustrated in Figure 7. The bottom of the hole at 1,130 feet was displaced 11 feet horizontally north from the first reading taken at a depth of 425 feet.

A three-arm 15-inch span caliper survey was run on Well H0-68 after the nitro shot was used for completion stimulation of the well (Figure 5). The maximum deflection of the caliper was 10-3/4 inches, and the average hole diameter after shot was 8.5 inches (before shot 7.75 inches).

The reservoir temperature of the Bradford Third Sand (Figure 5) was measured at 64⁰F. in Well H0-68. The temperature survey was run 46 days after the well was shot with nitro. The stabilized fluid level from the log indicated 517 feet of fluid above the top of the Bradford Third Sand for a calculated reservoir pressure of 224 psi based on a water gradient of 0.433 psi/foot. A summary of the average reservoir properties for the Bradford Third Sand based on core and log data from Well H0-68 is shown on Table 8.

Completion

The Bradford Third Sand interval 1,085 feet to 1,124 feet was shot with 155 quarts of liquid nitro on March 19, 1975, as shown in Figure 8.

The well was cleaned out to 1,131 feet total depth, and a caliper log was run to determine the size of the shot hole and to select a seat for the open hole packer. The well was tubed with 2-7/8 inch EUE tubing internally-coated with coal tar epoxy, and a Butler-Larkin tension packer (Type CK, Fig. C-134) was set at 1,080 feet. The well was completed and ready for fluid injection on March 26, 1975. The completed wellbore diagram is shown on Figure 8.

Surface and Wellhead Facilities

The supporting surface facilities for Phase I consist of a filtration and polymer mix plant, shear plant, pressure plant, office lab for quality control, and storage tanks. These facilities are leased to the project and are shown in schematic on Figure 9. The systems which handle polymer and slug solutions are installed with plastic piping and internally plastic-coated steel to minimize the potential of iron pick-up which is detrimental to polymer and causes wellbore plugging.

Fresh water is furnished from Lawry WSW No. 5 equipped with a 2.5 HP submersible pump to provide an adequate water supply of 350 BPD. The supply well

is located approximately 550 feet west of Well H0-68 and produces good quality water (for analysis see Table 9). Supply water is treated with sodium hypochlorite for bacterial control and is filtered through a Lakeside coal-bed filter.

The filtration and polymer mix plant houses the 5-foot x 5-1/2-foot Lakeside coal-bed filter, a 50-square foot DeLaval DE filter complete with precoat and slurry tanks, an Acrison Model 120-E mixer for dry polymer, two centrifugal pumps for transferring fluids, and meters for fluid measurement. An 85-barrel epoxy-coated polymer concentrate tank is located outside the building.

The shear plant is used in the second stage of polymer mixing. The hydration of a dry Xanthan polymer is accelerated by shearing a concentrate solution. The shear plant contains a centrifugal pump for fluid transfer and circulation and an Oilwell C-323 triplex pump with 25 HP electric motor. The piping discharge on the triplex pump is such that the polymer concentrate solution is sheared through a series of three orifice plates taking a 500 psi pressure drop per plate.

The pressure plant contains an FWI P-200-A triplex pump with 5 HP electric motor and a Milroyal Model C pump with 2 HP electric motor complete with Mercoid pressure controls. The Milroyal Model C pump is a constant speed, variable stroke pump with positive volume control from 0.2 BPD to 42 BPD. Although both pumps were used for Phase I injection, the Milroyal volume control pump provided over 99 percent of the injection requirements.

The office and lab are provided for operational and quality control supervision. Millipore tests, Brookfield viscosity measurements, pH, total iron, and chlorine measurements were made on a daily basis. A very high degree of quality control

was maintained during Phase I, and all injected fluids were required to pass a 0.45 micron millipore test.

Phase I tank storage facilities contain four 210-barrel epoxy-coated tanks. One tank is used for Lakeside filtered fresh water and three tanks are used for polymer or micellar slug. The tanks are equipped with gas jet burners for heating during winter operations.

A flow schematic for the facility is shown in Figure 10. The well is located 40 feet away on the same elevation from the plant. The piping is 1-inch internally plastic-coated steel equipped with two 5-micron cartridge type filters - one located inside the pressure plant and the other on the wellhead. Fluid is metered with a Hersey water meter located inside the pressure plant, and injection pressure is measured at the wellhead and by a pressure recorder located inside the pressure plant.

The wellhead installation, as shown on Figure 11, is equipped with a lubricator for running a bottomhole pressure bomb without interrupting fluid injection. The installation is also equipped with a sample port, pressure gauge, and dead weight pressure connection. The well was winterized by providing a small insulated enclosure and a heat lamp to prevent freezing.

Fluid Injection

Summary

One of the objectives of Phase I of the Lawry Project was to determine the injectivity characteristics of Marafloodtm process fluids in the low permeability Bradford Third Sand reservoir. A summary of fluid injection into Well H0-68 for the year ending June 30, 1976 is shown on Table 10. The injection curve for the same period is shown on Figure 12.

Fluid injection into Well H0-68 covered four separate periods utilizing three different fluids. The four injection periods and associated fluids were as follows: Pre-slug, 3,415 barrels of water injected; Slug, 452 barrels of micellar solution injected; Mobility Buffer, 2,867 barrels of biopolymer injected; and post polymer, 3,650 barrels of water injected through June 30, 1976.

Pre-Slug Injection - Water

Water injection was started on July 9, 1975 into the Bradford Third Sand interval 1,080 feet to 1,130 feet of Well H0-68.

The injection pressure was initially restricted not to exceed 600 psig wellhead, which, when converted to bottomhole pressure, was below the known formation parting pressure in this area of the Bradford Field. The initial injection rate was 76 BPD at 580 psig wellhead pressure. The injection rate was set at a constant volume of 41 BPD on July 20, 1975. Water injection was maintained at the 41 BPD rate until October 3, 1975. The wellhead pressure gradually increased from 445 psig on August 1 to 510 psig on October 3, when the cumulative pre-slug water injected was 3,415 barrels.

During pre-slug water injection, the following tests were run: Pressure Fall-off; Tracer Surveys; Step-rate, 4 points of 24 hours each, and Step-rate, 16 points of 1/4 hour each. Well H0-68 was shut in for a 24-hour pressure fall-off test on July 24, 1975 after injecting 797 barrels of water. The data and analysis of this test are discussed under the section titled "Fall-off Tests".

A Temperature Log and Tracer Survey using radioactive beads and solution were run on Well H0-68 on August 11, 1975 following the injection of 1,500 barrels of water. The logs were run while maintaining stabilized water injection at a rate

of 41 BPD at 465 psig wellhead pressure. The tracer surveys indicated a complete packer seal at 1,080 feet. The percentage injectivity into different intervals of the Bradford Third Sand reservoir is shown in Table 11.

A four-point step-rate injectivity relationship for water injection was determined by varying the injection rate and allowing the pressure to stabilize over a 24-hour period. The test was conducted during August 16-19, 1975. Prior to starting the test, the water injection rate was reduced from 41 BPD to 12 BPD for a 24-hour pressure stabilization period. The results of the four different rates are shown on Figure 13 and are tabulated in Table 12.

A sixteen-point step-rate injectivity test was run to determine if a critical injection pressure existed within the reservoir under a wellhead pressure limit of 1,000 psig. The test was run on September 5, 1975 after injecting 2,326 barrels of water. Prior to starting the test, the injection rate was reduced from 41 BPD to 10 BPD for a 48-hour pressure stabilization period. The test was conducted by increasing the wellhead injection pressure in 50 psi increments, from 250 psig to 1,000 psig, by increasing the injection rate. The results of the test are shown on Figure 14 and are tabulated in Table 12. No adverse injection performance was indicated, and the injection rates which were maintained for a very short time interval do not represent the sustained injection capacity of this well.

Slug Injection - Micellar Solution

The micellar slug was prepared under the supervision of Marathon Oil Company and to specifications similar to a slug which had been successfully injected into another Penn Grade reservoir. The slug was mixed at Pennzoil's Project No. 7 (Bingham Flood) test site at Cyclone, Pennsylvania. The composition

is listed in Table 13.

The slug was DE filtered at Cyclone to pass a 0.45 micron millipore test and was transferred by 100-barrel tank truck to the Lawry test site 12 miles away. The physical properties of the micellar slug were measured and are listed in Table 14.

A total of 452 barrels of micellar slug was injected into Well H0-68 during the period October 3-27, 1975. The average injection rate was 20.5 BPD over the 24-day period. The injection rate was maintained at a constant value for 22 days, and the wellhead injection pressure, taken with a dead weight gauge, increased from 510 psig to 923 psig.

A pressure fall-off test, which will be mentioned in the section titled "Fall-off Tests", was run for two days. A daily sample was taken at the wellhead and checked for viscosity and 0.45 micron millipore quality control.

Mobility Buffer Injection - Biopolymer

Prior to the completion of the micellar slug injection, Marathon advised Pennzoil, as operator, to follow the slug injection with a polymer initially having a viscosity of 6 to 7 centipoise. This viscosity was to be maintained until a reasonably stable injection pressure-rate relationship was obtained and then the viscosity was to be increased to 10 centipoise.

The mobility buffer used in Well H0-68 was a custom-prepared polysaccharide biopolymer broth. Both 7 centipoise and 10 centipoise polymer solutions were injected during different periods of mobility buffer injection, and the broth was mixed to approximately 350 ppm for 7 centipoise polymer and 500 ppm for 10 centipoise polymer. The biopolymer was DE filtered to pass a 0.45 micron

millipore test. No shearing operation for polymer hydration was necessary in preparing the biopolymer solution.

A total of 2,867 barrels of biopolymer was injected into Well H0-68 during the period October 27, 1975 to February 25, 1976. Injection was started with 7 centipoise biopolymer solution. Viscosity was increased to 10 centipoise on January 16, 1976 and reduced to 7 centipoise again on February 19, 1976. During the injection period the following tests were run: Step-rate (7 cp viscosity), Step-rate (10 cp viscosity), and Pressure Fall-off (7 cp viscosity) discussed elsewhere under the section titled "Fall-off Tests".

The initial injection rate for the 7 centipoise biopolymer was 20 BPD at 850 psig wellhead pressure. The injection rate was maintained constant at 20 BPD and the wellhead injection pressure stabilized at 877 psi after six days.

A four-point step-rate injectivity relationship for 7 cp viscosity biopolymer injection was determined by varying the injection rate and allowing the pressure to stabilize. The test was conducted by going from lower to higher rates and allowing the injection pressure to stabilize over a 10-day period at each rate. The results of the four different rates are shown on Figure 15 and are tabulated in Table 15.

The 7 cp viscosity biopolymer injection curve indicates that pressure parting occurred in the formation when the rate was increased from 35 BPD to 40 BPD, and the wellhead injection pressure exceeded the critical pressure of 1,165 psig.

A four-point step-rate injectivity relationship for 10 cp viscosity biopolymer injection was determined by varying the injection rate and allowing the pressure to stabilize. Prior to starting the test, the 7 cp viscosity biopolymer

injection rate was reduced from 40 BPD to 20 BPD for an eight-day pressure stabilization period. The biopolymer viscosity was then increased from 7 cp to 10 cp and the test was conducted by going from lower to higher injection rates and allowing the pressure to stabilize. The pressure stabilization periods for the first two injection rates were for 10 days each and the last two rates were for 6 days each. The results of the four different rates are shown on Figure 16 and are tabulated in Table 15.

The 10 cp viscosity biopolymer injection curve indicates that pressure parting occurred in the formation when the rate was increased from 25 BPD to 30 BPD, and the wellhead injection pressure exceeded 1,122 psig. Some packer leakage was also observed while injecting biopolymer at a rate of 35 BPD at 1,130 psig wellhead pressure. The packer leakage appeared to be minor, as the fluid flow observed at the wellhead ceased after approximately three hours, and the total circulated volume measured approximately one barrel. The fluid leak-off into the open hole interval from the bottom of the surface casing to the packer (420 feet to 1,080 feet) was believed to be insignificant. The interval was tested at 0.8 BPD leak-off rate, with water under hydrostatic head, in Well H0-67 located 25 feet from Well H0-68.

The calculated critical formation parting pressure and gradient as determined from the biopolymer step-rate tests are shown in Table 15. The results show that the low permeability Bradford Third Sand in Well H0-68 will accept both 7 centipoise and 10 centipoise biopolymer injection at pressures below the established critical parting pressure as shown below:

<u>Biopolymer Viscosity</u>	<u>Injection Rate-BPD</u>	<u>Critical Wellhead Pressure PSIG</u>
7 cp	35	1165
10 cp	28 (extrapolated)	1165

After completing the 10 cp step-rate injectivity test, the biopolymer injection rate was reduced from 35 BPD to 20 BPD and the viscosity was reduced from 10 cp to 7 cp. The injection of 7 cp biopolymer was maintained for six days and the well was returned to water injection.

Post Polymer Injection - Water

Well H0-68 was returned to water injection on February 25, 1976 at a rate of 20 BPD at 962 psig wellhead pressure. The 20 BPD rate was maintained for ten days and the wellhead injection pressure dropped from 962 psig to 900 psig. The water injection rate was increased from 20 BPD to 30 BPD and was maintained at that rate for the remainder of the test. The June 30, 1976 water injection rate was 30 BPD at 1,025 psig wellhead pressure and the cumulative water injected following biopolymer was 3,650 barrels.

Fall-off Tests

Summary

Three pressure fall-off tests were conducted on Well H0-68 to determine the reservoir characteristics of the Bradford Third Sand in the vicinity of the test well. Analyses of the fall-off data were used to determine fluid transmissibility, wellbore skin effect, the possible presence of a fracture, and the limits of the reservoir or the area of investigation. The conventional methods of fall-off interpretation to determine reservoir characteristics cannot be used, however, for slug and polymer fluids without some modifications. Therefore, analyses of the data for the micellar slug and biopolymer fall-off tests will not be presented.

The analysis of the pre-slug water fall-off test was used to determine reservoir characteristics, and it also gave an indication of a wellbore fracture. The results of the analysis can be found in Table 2 of Appendix B and are summarized

as follows: Fluid Transmissibility (kh), 34.0 md-feet; Skin Factor, -3.1 to -4.2; and volume investigated during the 24-hour Fall-off Test, 1.9 to 19 acres.

Fresh Water Fall-off

Fresh water injection was started on July 9, 1975 and a total of 797 barrels of water was injected, prior to conducting the 24-hour pressure fall-off test from July 24-25, 1975. The fresh water fall-off test schedule is shown on Table 16.

The bottomhole pressure recording instrument was an Amerada Type RPG-3 with a 1,600 psi element and a 72-hour clock. The BHP chart was forwarded to Marathon's Denver Research Center for interpretation and analysis of the fall-off data.

The pressure data used by Marathon in the evaluation is listed in Table 1 of Appendix B. Because of their greater reliability, the data recorded manually by Pennzoil with dead weight gauge and downhole pressures corrected to wellhead were used in the evaluation.

A type curve (log-log relationship) of Δp versus Δt was utilized to determine the portion of data that could be analyzed to determine valid reservoir characteristics. The relationship is shown on Figure 1 of Appendix B. Compressive wellbore storage effect became insignificant shortly after water injection stopped. The 0.5 slope exhibited on the type curve indicates the presence of a fracture. This was also substantiated by the core analysis in Table 3. The point in time at which the fall-off data is no longer influenced by the fracture and can be evaluated by normal methods is not clear from this type curve.

A Horner Plot analysis was used to determine the reservoir characteristics.

The shut-in surface pressure was plotted versus $t + \Delta t / \Delta t$ on semi-log paper and is presented in Figure 3 of Appendix B. A straight line relationship was determined after 10 hours and resulted in a slope value of 201 psi/cycle and a 1-hour

pressure value of 321 psi. The summary of calculations and assumptions for the pre-slug water fall-off test analyses can be found in Table 3 of Appendix B.

PHASE II - 24 ACRE TEST

Decision

The final objective of Phase I was to make a decision to proceed with a pattern test to evaluate the commercial application of the micellar-polymer process. The Miscible Operating Committee for the Penn Grade-ERDA Lawry Micellar Displacement Project approved the initiation of Phase II on May 3, 1976.

Objectives

The objectives of Phase II (Main Test) of the Lawry Project are:

- 1) Develop 24-acre pattern test consisting of nine enclosed five-spots on one and one-half acre spacing. This will require the drilling of 41 new wells (16 injectors and 25 producers) and the coring of 16 injectors and the center producer. (See Figure 3).
- 2) Determine the reservoir properties based on core and log data.
- 3) Install plant and field equipment for operations of micellar-polymer flood.
- 4) Inject pre-slug water to condition the reservoir fluids for slug injection.
- 5) Inject Marafloodtm micellar slug.
- 6) Inject mobility control polymer solution.

- 7) Provide for a major decision point for a performance evaluation after 50 percent of a pore volume of slug and polymer has been injected.
- 8) Inject water.
- 9) Post-injection evaluation of the project.

Phase II is programmed for a period of four years. The objectives are placed in the proper perspective of time by the Milestone Chart as shown on Figure 17. The estimated cost of the total project is \$4,444,000 and the calendarized budget for Phase I and II is shown by years on Table 17.

Development Status as of June 30, 1976

The development drilling for Phase II will be done with cable tool rigs. Diamond cores will be taken by utilizing a portable rotary table, drill pipe and fluid pump. The producers and injectors will be completed open-hole with nitro shot stimulation.

As of June 30, 1976, five cable tool rigs were operating and two injectors (H0-69 and H0-70) and four producers (H-90, H-92, H-93, and H-94) had been completed.

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9	Water Analysis - Lawry WSW No. 5
10	Summary of Injection Test - Lawry H0-68
11	Summary of Radioactive Tracer Logs - Lawry H0-68
12	Summary of Water Step-Rate Injectivity Tests - Lawry H0-68
	Four-Point Step-Rate Water Injectivity Test
	Sixteen-Point Step-Rate Water Injectivity Test
13	Micellar Slug Composition
14	Micellar Slug Physical Properties
15	Summary of Biopolymer Step-Rate Injectivity Tests - Lawry H0-68
	7 cp Biopolymer Four-Point Step-Rate Injectivity Test
	10 cp Biopolymer Four-Point Step-Rate Injectivity Test
	Formation Parting Pressure and Gradient
16	Fresh Water Fall-off Test Schedule - Lawry H0-68
17	Calendarized Budget for Project

Table 1

CORE DATA

Lawry H-88

-21-

Sample No.	Permeability md	Cumulative Capacity md.-Ft.	Average Permeability md	Cumulative Fractional Capacity	Porosity Fractional	Cumulative Fractional Porosity Feet	Average Porosity
1	53.89	53.89			.1678	.1678	
2	49.45	103.43			.1703	.3381	
3	24.05	127.48			.1673	.5052	
4	12.63	140.11			.1453	.6505	
5	10.48	150.59			.1580	.8085	
6	10.10	160.69			.1452	.9537	
7	10.05	170.74	24.39	.6803	.1376	1.0913	.1559
8	9.92	180.66			.1520	1.2433	
9	9.10	189.76			.1142	1.3575	
10	9.02	198.78			.1437	1.5012	
11	8.68	207.46			.1551	1.6563	
12	6.43	213.89			.1517	1.8080	
13	6.41	220.50			.1468	1.9548	
14	5.47	225.77			.1335	2.0883	
15	5.20	230.97	15.40	.9203	.1499	2.2382	.1492
16	4.89	235.86			.1492	2.3874	
17	4.83	240.69			.1411	2.5285	
18	2.81	243.50			.1489	2.6774	
19	1.87	245.37			.1416	2.8190	
20	1.48	246.85			.1479	2.9669	
21	1.35	248.20	11.82	.9889	.1537	3.1206	.1486
22	0.67	248.87			.1255	3.2461	
23	0.65	249.52			.1405	3.3866	
24	0.57	250.09			.1247	3.5113	
25	0.52	250.61			.1298	3.6411	
26	0.37	250.98	9.65	1.0000	.1119	3.7530	.1443

Table 2

DRILLERS LOG

Lawry H0-68

<u>Description</u>	<u>Top</u>	<u>Bottom</u>	<u>Gas</u> <u>At</u>	<u>Oil</u> <u>At</u>	<u>WATER AT</u> <u>(Fresh or</u> <u>Salt Water)</u>
Clay & Gravel	0	65			
Slate	65	75			
Sand	75	90			Fresh @ 75'
Slate	90	112			
Sand & Slate	112	130			
Sand	130	140			Fresh @ 130'
Sand & Slate	140	220			
Limestone & Slate	220	250			
Slate & Shells	250	330			
Lime & Slate & Shells	330	510			
Slate & Shells	510	600			
Sand	600	610			
Slate & Shells	610	640			
Slate	640	720			
Slate & Shells	720	950			
Slate	950	990			
Slate & Shells	990	1083			
Bradford Third Sand	1083	1131	Producing Sand		Oil Show
Total Depth		1131			

Table 3

CORE DESCRIPTION

Lawry H0-68

Core Fluid - 10,000 to 20,000 ppm NaCl

Note: All sand cored (6 inch core) bleeding oil.

Core #1 - March 11, 1975

1075.0
9.35
1084.35

1075.0	-	1075.9	Shale
1075.9	-	1078.5	Silty shale
1078.5	-	1079.25	Shale
1079.25	-	1080.25	Siltstone
1080.25	-	1080.45	Limey silt
1080.45	-	1081.5	Limey silt - shale (Fracture @ 1080.65)
1081.5	-	1083.35	Cap rock w/shells
1083.35	-	1084.35	Sand, very tight (Top of Pay @ 1083.35)

Core #2 - March 11, 1975

1084.35
9.73
1094.08

1084.35	-	1089.55	Sand, very tight - shale w/very thin sand lenses at bottom
1089.55	-	1090.0	Calcareous silt
1090.0	-	1092.6	Sand, very tight
1092.6	-	1092.7	Calcareous silt
1092.7	-	1094.08	Sand, very tight

Table 3

CORE DESCRIPTION (Cont'd.)

Lawry H0-68

Core #3 - March 12, 1975

1094.08
10.12
 1104.20

1094.08	-	1094.15	Shale
1094.15	-	1095.25	Shale & sand
1095.25	-	1096.35	Sand
1096.35	-	1096.45	Shale band
1096.45	-	1097.45	Sand
1097.45	-	1098.0	Sand - shale band
1098.0	-	1098.35	Sand
1098.35	-	1098.5	Shale
1098.5	-	1100.95	Sand, pebbles @ 1100.25
1100.95	-	1101.0	Shale
1101.0	-	1101.25	Sand
1101.25	-	1101.3	Shale
1101.3	-	1102.4	Sand
1102.4	-	1102.55	Shale
1102.55	-	1102.65	Sand
1102.65	-	1103.35	Sand - shale
1103.35	-	1103.5	Shale
1103.5	-	1104.2	Sand - shale bands

Core #4 - March 12, 1975

1104.2
9.25
 1113.45

1104.2	-	1105.6	Sand - shale bands
1105.6	-	1106.52	Sand
1106.52	-	1108.25	Shale - sand bands
1108.25	-	1109.48	Sand
1109.48	-	1110.5	Shale w/sand lenses
1110.5	-	1112.08	Sand
1112.08	-	1113.21	Shale w/sand lenses
1113.21	-	1113.45	Shale w/sand at bottom

Table 3

CORE DESCRIPTION (Cont'd.)

Lawry H0-68

Core #5 - March 14, 1975

1113.45
7.48
1120.93

1113.45	-	1113.85	Sand
1113.85	-	1115.25	Sand & shale mix
1115.25	-	1116.3	Sand (Fracture plane @ 1116.3)
1116.3	-	1117.65	Shale - sand mix
1117.65	-	1118.9	Sand
1118.9	-	1119.45	Limey silt (Angular shale plane)
1119.45	-	1120.3	Sand w/small pebbles
1120.3	-	1120.53	Shale w/pebbles in sand
1120.53	-	1120.93	Sand

Table 4

CORE ANALYSIS

Lawry H0-68

Sample	Depth	*Percent Porosity	<u>Percent Saturation</u>			Oil Content Bbls/Ac.Ft.	Permeability md	Remarks
			Oil	Water	**Connate			
1	1084'	15.58	35.1	35.3	2.6	424	32.97	Trace shale - Few shells
2	1085'	13.28	34.4	39.7	3.3	354	24.90	Trace shale
3	1087'	11.48	38.1	33.4	3.9	339	5.47	Hard sand
4	1091'	14.60	31.3	36.6	2.6	355	8.16	Good sand
5	1095'	15.08	34.0	34.6	4.5	398	12.53	Free oil
6	1099'	15.63	26.0	45.9	4.2	315	15.00	Very good sand
7	1100'	15.97	30.5	42.5	4.2	378	36.36	Very good sand

*Determined by fluid saturated method

**Estimated salinity 100,000 ppm

Table 5

LOGGING INFORMATION

Lawry H0-68

<u>Type Log</u>	<u>Logged Interval</u>	<u>Scale</u>
1) Nuclear Compensated Neutron	450' - TD	5"/100'
2) Gamma-Density & Caliper	400' - TD	5"/100'
3) Velocity	700' - TD	5"/100'
4) Induction	400' - TD	5"/100'
5) SP-Guard	450' - TD	5"/100'
6) Gamma-Guard & Caliper*	1,000' - TD	20"/100'
7) CDI Inclinator	425' - TD	25' Interval
8) Caliper (after nitro shot)	1,000' - TD	20"/100'
9) Temperature**	50' - TD	20"/100'

* Includes Gamma Ray curve from surface to TD on 2"/100' scale.

** Stabilized well temperature run 46 days after well was shot with nitro.

Table 6

COM-PRO LOG ANALYSIS

Lawry H0-68

<u>Depth Feet</u>	<u>Density Grams/CC</u>	<u>Porosity Percent</u>	<u>Water Saturation Percent</u>	<u>Oil Saturation Percent</u>	<u>Oil Res. In Place Bbl/Ac.-Ft.</u>	<u>Oil Permeability Millidarcy</u>
1,070.0	2.542	8.2	100.0	.0		.0
1,071.0	2.543	8.1	100.0	.0		.0
1,072.0	2.516	9.7	100.0	.0		.1
1,073.0	2.545	8.0	100.0	.0		.0
1,074.0	2.570	6.6	100.0	.0		.0
1,075.0	2.584	5.7	100.0	.0		.0
1,076.0	2.593	5.2	100.0	.0		.0
1,077.0	2.574	6.3	100.0	.0		.0
1,078.0	2.599	4.8	100.0	.0		.0
1,079.0	2.594	5.1	100.0	.0		.0
1,080.0	2.657	1.4	100.0	.0		.0
1,081.0	2.679	.0	100.0	.0		.0
1,082.0	2.675	.3	100.0	.0		.0
1,083.0	2.659	1.2	100.0	.0		.0
1,084.0	2.612	4.0	100.0	.0		.0
1,085.0	2.503	10.6	76.3	23.7	173	.1
1,086.0	2.453	13.5	59.5	40.5	378	1.1
1,087.0	2.465	12.8	61.9	38.1	337	.7
1,088.0	2.483	11.7	66.7	33.3	270	.4
1,089.0	2.465	12.8	60.0	40.0	354	.8
1,090.0	2.459	13.1	58.4	41.6	379	.9
1,091.0	2.493	11.1	69.0	31.0	238	.2
1,092.0	2.522	9.4	82.9	17.1	112	.1
1,093.0	2.514	9.9	80.0	20.0	137	.1
1,094.0	2.516	9.8	81.3	18.7	126	.1
1,095.0	2.546	8.0	99.4	.6	3	.0
1,096.0	2.554	7.5	100.0	.0		.0
1,097.0	2.552	7.6	100.0	.0		.0
1,098.0	2.518	9.7	80.7	19.3	129	.1

Table 6 (Continued)

COM-PRO LOG ANALYSIS

Lawry H0-68

<u>Depth Feet</u>	<u>Density Grams/CC</u>	<u>Porosity Percent</u>	<u>Water Saturation Percent</u>	<u>Oil Saturation Percent</u>	<u>Oil Res. In Place Bbl/Ac.-Ft.</u>	<u>Oil Permeability Millidarcy</u>
1,099.0	2.505	10.4	75.1	24.9	179	.1
1,100.0	2.499	10.7	72.8	27.2	203	.2
1,101.0	2.469	12.5	62.6	37.4	325	.6
1,102.0	2.465	12.8	61.6	38.4	340	.7
1,103.0	2.497	10.9	74.0	26.0	196	.2
1,104.0	2.534	8.7	96.4	3.6	22	.0
1,105.0	2.557	7.3	100.0	.0		.0
1,106.0	2.572	6.4	100.0	.0		.0
1,107.0	2.572	6.4	100.0	.0		.0
1,108.0	2.584	5.7	100.0	.0		.0
1,109.0	2.580	6.0	100.0	.0		.0
1,110.0	2.552	7.6	100.0	.0		.0
1,111.0	2.522	9.4	94.4	5.6	37	.0
1,112.0	2.538	8.5	100.0	.0		.0
1,113.0	2.509	10.2	85.4	14.6	103	.1
1,114.0	2.535	8.6	100.0	.0		.0
1,115.0	2.556	7.4	100.0	.0		.0
1,116.0	2.534	8.7	90.0	10.0	61	.0
1,117.0	2.544	8.1	93.7	6.3	35	.0
1,118.0	2.558	7.3	100.0	.0		.0
1,119.0	2.553	7.6	98.6	1.4	7	.0
1,120.0	2.511	10.1	74.7	25.3	177	.1
1,121.0	2.505	10.4	74.1	25.9	187	.1
1,122.0	2.491	11.3	72.0	28.0	219	.2
1,123.0	2.483	11.7	71.7	28.3	231	.3
1,124.0	2.501	10.7	80.3	19.7	145	.1
1,125.0	2.475	12.2	71.1	28.9	244	.4
1,126.0	2.493	11.1	78.6	21.4	164	.2

Table 7

CDI INCLINOMETER SURVEY

Lawry HO-68

In Survey Run

(Orientation Ref. Magnetic North)

Station Interval	Measured Depth	Vertical Depth	Inclination Deg.	Min.	Bearing Deg.	Horizontal Displace.	Azimuth Deg.	Min.	Rectangular North/South	Coordinates East/West	Dog Leg Severity
	425	425.00							0.0	0.0	
25	450	450.00	0	22	S 1.507 W	0.16	S	1 30 W	0.16 S	0.00 W	1.39
25	475	475.00	0	25	S 20.157 E	0.34	S	9 53 E	0.33 S	0.06 E	0.61
25	500	500.00	0	21	S 1.636 W	0.48	S	6 19 E	0.48 S	0.05 E	0.63
25	525	525.00	0	7	S 25.641 W	0.53	S	3 30 E	0.52 S	0.03 E	0.99
25	550	550.00	0	18	S 3.814 W	0.65	S	2 4 E	0.65 S	0.02 E	0.78
25	575	575.00	0	0	S 0.000 E	0.65	S	2 4 E	0.65 S	0.02 E	1.18
25	600	600.00	0	0	S 19.983 W	0.65	S	2 4 E	0.65 S	0.02 E	0.0
25	625	625.00	0	5	S 90.000 W	0.65	S	0 58 W	0.65 S	0.01 W	0.31
25	650	650.00	0	37	N 26.564 E	0.43	S	14 53 E	0.41 S	0.11 E	2.63
25	675	674.99	0	42	N 19.194 E	0.24	S	60 13 E	0.12 S	0.21 E	0.50
25	700	699.99	1	14	N 39.272 E	0.63	N	61 48 E	0.30 N	0.55 E	2.47
25	725	724.98	1	19	N 16.924 E	1.11	N	40 24 E	0.84 N	0.72 E	2.00
25	750	749.98	1	5	N 14.419 E	1.55	N	32 44 E	1.30 N	0.84 E	0.97
20	770	769.97	1	27	N 7.269 E	2.02	N	26 31 E	1.80 N	0.90 E	2.03
30	800	799.96	1	33	N 3.874 E	2.78	N	20 5 E	2.61 N	0.95 E	0.43
25	825	824.95	1	14	N 5.297 E	3.31	N	17 42 E	3.15 N	1.00 E	1.24
25	850	849.95	1	27	N 9.460 W	3.88	N	13 25 E	3.78 N	0.90 E	1.62
25	875	874.94	1	35	N 11.448 W	4.52	N	9 45 E	4.45 N	0.76 E	0.55
25	900	899.93	1	28	N 4.487 W	5.14	N	7 59 E	5.09 N	0.71 E	0.87
25	925	924.92	1	16	N 13.816 E	5.69	N	8 33 E	5.62 N	0.85 E	1.90
25	950	949.91	1	42	N 15.044 W	6.38	N	5 53 E	6.34 N	0.65 E	3.42
25	975	974.90	1	53	N 7.460 W	7.18	N	4 22 E	7.16 N	0.55 E	1.18
25	1000	999.88	1	48	N 12.145 W	7.93	N	2 45 E	7.92 N	0.38 E	0.68
25	1025	1024.88	1	24	N 8.589 W	8.53	N	1 57 E	8.52 N	0.29 E	1.64
25	1050	1049.87	1	20	N 19.650 W	9.07	N	0 36 E	9.07 N	0.10 E	1.08
25	1075	1074.86	1	27	N 10.039 W	9.70	N	0 5 W	9.70 N	0.02 W	1.06
25	1100	1099.85	1	25	N 11.307 W	10.31	N	0 46 W	10.30 N	0.14 W	0.19
25	1125	1124.84	1	27	N 12.610 W	10.93	N	1 27 W	10.92 N	0.28 W	0.21
5	1130	1129.84	1	24	N 12.900 W	11.05	N	1 34 W	11.04 N	0.30 W	1.12

Horizontal Departure = 11.05 Feet At N 1. Deg. 34. Min. W

Table 7 (Continued)

CDI INCLINOMETER SURVEY

Lawry HO-68

Out Survey Run

(Orientation Ref. Magnetic North)

Station Interval	Measured Depth	Vertical Depth	Inclination Deg.	Min.	Bearing Deg.	Horizontal Displace.	Azimuth Deg.	Min.	Rectangular North/South	Coordinates East/West	Dog Leg Severity
	425	425.00							0.0	0.0	
25	450	450.00	0	16	S 18.104 E	0.11	S 18	6 E	0.11 S	0.04 E	0.32
25	475	475.00	0	30	S 17.723 E	0.33	S 17	51 E	0.32 S	0.10 E	0.95
25	500	500.00	0	21	S 23.305 E	0.48	S 19	33 E	0.46 S	0.16 E	0.65
25	525	525.00	0	0	S 23.199 E	0.48	S 19	33 E	0.46 S	0.16 E	1.38
25	550	550.00	0	14	S 16.587 E	0.59	S 19	2 E	0.55 S	0.19 E	0.95
25	575	575.00	0	11	S 27.979 E	0.66	S 20	4 E	0.62 S	0.23 E	0.27
25	600	600.00	0	13	S 66.297 W	0.67	S 12	18 E	0.66 S	0.14 E	1.13
25	625	625.00	0	19	S 55.081 E	0.78	S 19	12 E	0.74 S	0.26 E	1.85
25	650	650.00	0	29	N 43.363 E	0.71	S 34	38 E	0.58 S	0.40 E	2.17
25	675	674.99	0	42	N 39.600 E	0.69	S 60	3 E	0.35 S	0.60 E	0.90
25	700	699.99	0	50	N 17.151 E	0.71	N 89	35 E	0.01 N	0.71 E	1.32
25	725	724.98	1	23	N 10.820 E	1.01	N 54	3 E	0.60 N	0.82 E	2.20
25	750	749.98	1	29	N 4.057 E	1.51	N 34	60 E	1.24 N	0.87 E	0.78
25	775	774.97	1	23	N 22.950 E	2.10	N 31	35 E	1.79 N	1.10 E	1.91
25	800	799.96	1	23	N 7.606 E	2.67	N 26	17 E	2.39 N	1.18 E	1.48
25	825	824.95	1	11	N 7.688 E	3.16	N 23	17 E	2.91 N	1.25 E	0.80
25	850	849.95	1	21	N 6.967 W	3.69	N 18	39 E	3.49 N	1.18 E	1.45
25	875	874.94	1	35	N 4.148 W	4.33	N 15	7 E	4.18 N	1.13 E	0.97
25	900	899.93	1	42	N 6.393 W	5.03	N 12	1 E	4.92 N	1.05 E	0.53
25	925	924.92	1	22	N 2.924 E	5.61	N 11	4 E	5.51 N	1.08 E	1.66
25	950	949.91	1	54	N 6.487 W	6.41	N 8	50 E	6.33 N	0.98 E	2.37
25	975	974.90	1	39	N 13.653 W	7.07	N 6	37 E	7.03 N	0.81 E	1.33
25	1000	999.88	1	52	N 3.517 W	7.88	N 5	34 E	7.84 N	0.76 E	1.52
25	1025	1024.87	1	26	N 8.184 W	8.49	N 4	34 E	8.46 N	0.68 E	1.81
25	1050	1049.87	1	19	N 15.025 W	9.03	N 3	20 E	9.02 N	0.53 E	0.80
25	1075	1074.86	1	25	N 7.447 W	9.64	N 2	39 E	9.63 N	0.45 E	0.83
25	1100	1099.85	1	23	N 8.244 W	10.24	N 2	1 E	10.23 N	0.36 E	0.16
25	1125	1124.84	1	27	N 10.845 W	10.85	N 1	16 E	10.85 N	0.24 E	0.37
5	1130	1129.84	1	24	N 13.144 W	10.97	N 1	6 E	10.97 N	0.21 E	1.58

Horizontal Departure = 10.97 Feet At N 1. Deg. 6. Min. E

Bottom Hole Separation = 0.52

Table 8

AVERAGE RESERVOIR PROPERTIES

Lawry H0-68

	<u>Core*</u>	<u>Log</u>
1) Top of Bradford Third Sand	1083.3	1084
2) Net Pay, feet	--	25
3) Porosity, percent	14.5	11.2
4) Permeability, millidarcys	19.3	--
5) Oil Saturation, percent	32.8	27.9
6) Formation Volume Factor	1.0	1.0
7) Reservoir Temperature, °F.	--	64
8) Reservoir Pressure, psi	--	224
9) Wellbore Diameter, inches	7.75	8.5**

* Seven Samples

** After Nitro Shot

Table 9

WATER ANALYSIS

Lawry WSW No. 5

Sample No.		1
Date Sampled		4-25-75
Date Received		Same
Point of Sampling		Supply Well No. 5
Appearance When Sampled		Very Clear
Appearance After Standing		Very Clear
Sediment After Standing		None
Temperature When Sampled	^o F	50
Color	U.S.G.S. Units	< 1
Odor		sl. H ₂ S
pH		7.3
Carbon Dioxide	CO ₂	18
Dissolved Oxygen	O ₂	0.16
Hydrogen Sulfide	H ₂ S	1.9
Residual Chlorine	Cl ₂	-
Turbidity	Jackson Units	3
Total Iron	Fe	0.21
Dissolved Iron	Fe	0.10
Manganese	Mn	< 0.01
Chlorides	Cl	31
Sulfates	SO ₄	< 0.1
Alkalinity to Phenolphthalein	asCaCO ₃	0
Alkalinity to Methyl Orange	asCaCO ₃	190
Total Hardness	asCaCO ₃	164
Sodium	Na	15
Calcium	Ca	43
Magnesium	Mg	14
Phosphate	PO ₄	0
Total Dissolved Solids (Sp. Conductivity)		258

Values are parts per million (ppm) unless indicated otherwise.
 17.1 ppm equal 1 grain per U.S. gallon - < means "less than".

Table 10

SUMMARY OF INJECTION TEST

Lawry H0-68

Date	Water Injection		Slug Injection		Polymer Injection		Viscosity CP @ 64° F.	End of Month Wellhead Press.-Psig.
	Avg. B/D	Cum-Bbls.	Avg. B/D	Cum-Bbls.	Avg. B/D	Cum-Bbls.		
7-75	49.9	1048	-	-	-	-	1.0	445
8-75	36.6	2183	-	-	-	-	1.0	480
9-75	36.9	3291	-	-	-	-	1.0	515
10-75	41.3	3415	20.5	452	16.8	67	S - 11.9 P - 6.8	S - 923 P - 882
11-75	-	-	-	-	20.3	502	7.0	865
12-75	-	-	-	-	30.5	1355	7.1	1173
1-76	-	-	-	-	26.1	2164	7.0 10.0*	1128
2-76	20.3	(81)	-	-	28.1	2867	10.2 7.2**	P - 975 W - 885
3-76	27.2	(896)	-	-	-	-	1.0	1054
4-76	30.1	(1800)	-	-	-	-	1.0	1075
5-76	30.3	(2740)	-	-	-	-	1.0	1100
6-76	30.4	(3650)	-	-	-	-	1.0	1025

NOTE: Water Injection Started 7-9-75
 Slug Injection Oct. 3 to 27, 1975
 Polymer Injection Started 10-27-75
 Changed from Polymer to Water 2-25-76

*Increased Viscosity on 1-16-76
 **Reduced Viscosity on 2-19-76

Table 11

SUMMARY OF RADIOACTIVE TRACER LOGS

Lawry H0-68

Tracer Logs Dated 8-11-75

<u>RA - Solution</u>		<u>RA - Beads</u>		
<u>Interval</u>	<u>% Injection</u>	<u>Interval</u>	<u>% Injection</u>	
1090 - 1095	20	1090 - 1094	4	
1102 - 1106	64	1094 - 1098	16	<u>20%</u>
1106 - 1115	<u>16</u>	1098 - 1100	8	
		1100 - 1102	12	
		1102 - 1104	23	
		1104 - 1106	12	<u>55%</u>
Total	100%	1106 - 1108	9	
		1108 - 1110	9	
		1110 - 1112	3	
		1112 - 1114	2	
		1114 - 1116	<u>2</u>	<u>25%</u>
		Total	100%	

Table 12

SUMMARY OF WATER STEP-RATE INJECTIVITY TESTS

Lawry H0-68

Four-Point Step-Rate Water Injectivity Test

<u>Water Injection Rate - BPD</u>	<u>Wellhead Pressure Psig</u>
11.4	175
21.6	225
30.7	310
40.9	420

Sixteen-Point Step-Rate Water Injectivity Test

<u>Time Interval Hrs - Minutes</u>	<u>Injection Rate B/D</u>	<u>Wellhead Pressure Psig</u>
0 - 15	51	250
0 - 30	60	300
0 - 45	76	350
1 - 0	83	400
1 - 15	88	450
1 - 30	96	500
1 - 45	105	550
2 - 0	114	600
2 - 15	123	650
2 - 30	135	700
2 - 45	149	750
3 - 0	163	800
3 - 15	176	850
3 - 30	184	900
3 - 45	196	950
4 - 0	201	1000

Table 13

MICELLAR SLUG COMPOSITION

	<u>Bbls.</u>	<u>Volume %</u>
TRS - 16*	32.2	5.46
TRS - 40*	32.5	5.51
Diesel	106.0	17.97
Amyl Alcohol	14.0	2.37
Butyl Alcohol	3.9	0.66
Water	<u>401.4</u>	<u>68.03</u>
Total	590.0	100.00

*Witco Brand Sulfonate

Table 14

MICELLAR SLUG PHYSICAL PROPERTIES

Viscosity - Brookfield @ 6 rpm	-	11.4 Centipoise @ 68 ⁰ F. 11.9 Centipoise @ 64 ⁰ F.
Specific Gravity	-	0.972 @ 64 ⁰ F.
Critical Temperature	-	110 ⁰ F. - High 52 ⁰ F. - Low

Table 15

SUMMARY OF BIOPOLYMER STEP-RATE INJECTIVITY TESTS

Lawry H0-68

7 cp Biopolymer Four-Point Step-Rate Injectivity Test

<u>Injection Rate-BPD</u>	<u>Wellhead Injection Pressure Psi</u>
20	890
30	1080
35	1165
40	1178

10 cp Biopolymer Four-Point Step-Rate Injectivity Test

<u>Injection Rate-BPD</u>	<u>Wellhead Injection Pressure Psi</u>
20	1050
25	1122
30	1125
35	1130

Formation Parting Pressure and Gradient

	<u>Biopolymer</u>	
	<u>7 cp</u>	<u>10 cp</u>
Critical Wellhead Inj. Pressure - psi	1165	1122
Hydrostatic Head @ 1,084 feet - psi	<u>469</u>	<u>469</u>
BHP @ 1,084 feet (Top of Sand) - psi	1634	1591
Parting Pressure Gradient - psi/ft.	1.50	1.46

Table 16

FRESH WATER FALL-OFF TEST SCHEDULE

Lawry H0-68

<u>July 1975</u>	<u>Time</u>	<u>Remarks</u>
20th		Inj. 41.6 BPD @ 400 psi
21st		Inj. 41.1 BPD @ 400 psi
22nd		Inj. 43.0 BPD @ 410 psi
	9:30 a.m.	BHP Bomb @ 1,076' (Log Depth)
23rd		Inj. 42.3 BPD @ 420 psi
24th		Inj. 42.1 BPD @ 420 psi
	9:30 a.m.	Shut Well In
25th	9:30 a.m.	Pulled BHP Bomb (72-hr.) and returned Well to Injection.

Table 17

CALENDARIZED BUDGET FOR
PENN GRADE MICELLAR DISPLACEMENT PROJECT

<u>Year</u>	<u>Wells</u>	<u>Plant</u>	<u>Micellar Slug</u>	<u>Mobility Buffer</u>	<u>Operation</u>	<u>Core Evaluation</u>	<u>Design and Engineering</u>	<u>Total</u>
1975								
Injectivity Test (Phase I)	\$ 65,000	\$ 25,000	\$ 5,000	\$ 8,000	\$ 80,000	\$ 9,000	\$ 75,000	\$ 267,000
1976								
Main Test (Phase II)	\$1,097,000	\$325,000	-	-	\$ 50,000	\$ 79,000	\$ 90,000	\$1,641,000
1977	-	-	334,000	91,000	270,000	-	28,000	723,000
1978	-	-	-	170,000	240,000	-	30,000	440,000
1979	-	-	-	91,000	214,000	-	33,000	338,000
1980	<u>495,000</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>240,000</u>	<u>190,000</u>	<u>110,000</u>	<u>1,035,000</u>
Total *	\$1,657,000	\$350,000	\$339,000	\$360,000	\$1,094,000	\$278,000	\$366,000	\$4,444,000

*ERDA - Penn Grade Contract No. E (46-1) - 8002

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FIGURE 2

FIGURE 4

LAWRY HO-68

FIGURE 5

LAWRY HO-68

COM - PRO LOG

Q FACTOR

S P I

FIGURE 6
COM - PRO ANALYSIS
LAWRY HO - 68

BIRDWELL C.D.I. INCLINOMETER SURVEY
 PENNZOIL
 WELL HO-68
 BRADFORD FIELD
 M KEAN CO., PENNSYLVANIA

IN RUN (x)
 VERT. DEPTH = 1129.84 FT.
 OUT RUN (o)
 VERT. DEPTH = 1129.84 FT.

BOTTOM HOLE SEPARATION=0.52 FT.

FIGURE 7

FIGURE 8

WELL BORE DIAGRAM

LAWRY HO-68

STORAGE TANKS
4-210 Bbl. Epoxy Coated tanks.

FIGURE 9
FACILITIES SCHEMATIC
LAWRY PROJECT PHASE 1

FIGURE 10
FLOW SCHEMATIC
LAWRY PROJECT PHASE I

FIGURE 11
WELLHEAD INSTALLATION
LAWRY HO-68

FIGURE 12

FIGURE 15

BIOPOLYMER (7.0 cp VISCOSITY) FOUR POINT

STEP-RATE INJECTIVITY TEST - LAWRY H0-68

		DATE
1	20 BPD @ 890#	12-9-75
2	30 BPD @ 1080#	12-19-75
3	35 BPD @ 1165#	12-29-75
4	40 BPD @ 1178#	1-8-76

-56-

RATE B/D

PSI WELLHEAD PRESSURE

FIGURE 16

BIOPOLYMER (10 cp VISCOSITY) FOUR POINT

STEP-RATE INJECTIVITY TEST - LAWRY HO-68

DATE

1	20 BPD @ 1050 PSI	1-26-76
2	25 BPD @ 1122 PSI	2-5-76
3	30 BPD @ 1125 PSI	2-12-76
4	35 BPD @ 1130 PSI	2-19-76

RATE B/D

50
40
30
20
10

PSI - WELLHEAD PRESSURE

MILESTONE CHART

PENN GRADE MICELLAR DISPLACEMENT PROJECT

CONTRACT EY-76-C-21-8002
BRADFORD FIELD, PENNSYLVANIA

COORDINATING AND REPORTING

LAB SUPPORT

LAB SUPPORT

DESIGN PATTERN & PLANT FACILITIES

INJECTION
TEST
DESIGN

ANALYZE
INJECTION TEST

DESIGN PROCESS
FOR
PATTERN TEST

FINAL
REPORT

J F M A M J J A S O N D	J F M A M J J A S O N D	J F M A M J J A S O N D	J F M A M J J A S O N D	J F M A M J J A S O N D	J F M A M J
1975	1976	1977	1978	1979	1980

DECISION POINTS

FIGURE 17

SOCIETY OF PETROLEUM ENGINEERS OF AIME
6200 North Central Expressway
Dallas, Texas 75206

PAPER SPE 4753
NUMBER

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Tertiary Recovery by the Maraflood Process in the Bradford Field

By

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Discussion of this paper is invited. Three copies of any discussion should be sent to the Society of Petroleum Engineers office. Such discussion may be presented at the above meeting and, with the paper, may be considered for publication in one of the two SPE magazines.

ABSTRACT

Following an encouraging pilot test, a large scale project using the Maraflood* oil recovery process was initiated in the Bradford Field in Pennsylvania. The expanded project of 47 acres utilized the old waterflood five-spot pattern in the area. A dramatic oil production response occurred at this project. The test has now progressed into a stabilized production decline from which a prediction can be made of future performance. Field testing has shown that tertiary oil can be recovered by the process from a previously waterflooded oil-wet Bradford Third Sand reservoir.

INTRODUCTION

Numerous laboratory tests have been conducted to study oil displacement with micellar solutions. (1-7) These lab tests and certain field tests have demonstrated that additional oil can be recovered by using micellar slugs followed by thickened water solutions. (8-10)

*The "Maraflood" (trademark of Marathon Oil Co.) oil recovery process.

References and illustrations at end of paper.

In the Bradford Field of Pennsylvania where the waterflooding technique began, many different tertiary oil recovery methods have been attempted with limited success. (11-12) The purpose of this paper is to present the results of the first successful field project to recover tertiary oil from the Bradford Third Sand reservoir. The performance of this test will be evaluated and the operations summarized.

This project is testing the Maraflood* oil recovery process on leases of the Pennzoil Company, operator of the test. Pennzoil is using the Maraflood process under license from the Marathon Oil Company.

Process Description

The process is a method of producing oil under both secondary and tertiary recovery conditions. Micellar solutions make up the first in a series of displacing fluid banks injected into an oil-bearing formation. These solutions can displace a high percentage of the residual oil in the reservoir when properly designed. Micellar solutions contain primarily hydrocarbon, surfactant, and water. They are designed to be stable in the presence of

reservoir fluids and rock. For maximum recovery efficiency, it is preferable that a slug of micellar solution has sufficient viscosity to give favorable mobility control with respect to reservoir fluids. A mobility buffer is injected for the protection of the recovery efficiency of the slug. The mobility buffer is a bank with lower mobility than the slug. Water solutions containing polymers are normally used as the mobility buffer. Water is then injected to drive the slug and mobility buffer through the reservoir.

PROJECT LOCATION AND RESERVOIR DATA

Test Site

The Bingham Field Test is located in the Bradford Field in McKean County, Pennsylvania. The test includes a pilot and an expansion on the Bingham Lease situated in the southeastern edge of the Bradford Field. The 0.75 acre pilot test is located 500 feet southwest of the expansion. The expanded test consists of approximately 47 acres utilizing the original old waterflood five-spot pattern with a well spacing of slightly less than three acres. Figure 1 is a map showing the location of the test area within the Bradford Field. Maps of the pilot and the expanded test pattern are shown in Figures 2 and 3. The producing wells in the expansion are divided into two groups - farms "A" and "B". Farm A consists of approximately 26 acres with nine confined five-spots. The remaining 16 producing wells surround the pattern and make up farm B. Three observation wells (109, 110, 413) are located at points midway between injectors and producers.

Reservoir Data

The oil reservoir under test is the Bradford Third Sandstone. This interval is the major producing formation in the Bradford Field. Average reservoir properties are shown in Table 1. The reservoir in the test area occurs at subsurface depths in the range of 1,860 feet and generally can be divided into three principal zones. The Upper zone varies in thickness from 15 feet to 25 feet across the test pattern. It is composed of coarse silt to very fine sand. Permeability and porosity average 6.7 md and 13.1% respectively.

The Middle zone varies in thickness from 16 feet to 22 feet and is composed of very fine sand. Two regions of varying rock properties can be found within the Middle zone. These regions appear to correlate areally across portions of the test pattern. The Middle-High region has an average permeability and porosity of 157.8 md and 19.3% respectively. The

permeability and porosity of the Middle-Low region average 22.7 md and 13.8% respectively.

The Lower zone is composed of coarse silt to a very fine sand, and the thickness of this zone varies from 7 to 12 feet. Permeability and porosity average 11.3 md and 12.8% respectively. Figure 4 is a block diagram of the reservoir in the expanded test area illustrating the continuity both vertically and areally of the reservoir in the region of the test. It should be noted that in certain portions of the pattern, the zones are separated by shale lenses.

Core analyses were confined to the three observation wells in the expansion area, in addition to those in the initial pilot test area. Therefore, it was necessary to extrapolate average measured rock properties across the pattern using gamma ray logs correlated with the wells having core analyses. This approach consisted of:

1. Averaging the rock properties of each zone from core analyses on Wells 109, 110, and 413, in addition to the wells located in the pilot area.
2. Correlating the occurrence of the zones as defined by core descriptions and measured rock properties with deflections on the gamma ray log.
3. Assigning the average zonal rock properties to different vertical sections of the pay sand in wells without core analyses based on gamma ray log deflections which were similar in nature to those observed in the core wells.

Oil Saturation

The oil saturation after waterflooding has never been firmly established for the area because of limited and often conflicting data. Therefore, a detailed analysis of data pertaining to the oil saturation remaining after waterflood was made for the pilot area.

Results of this investigation using four different methods are tabulated below:

	<u>So Range</u>	<u>Midpoint of Range</u>
Routine Commercial		
Core Analyses	0.27-0.36	0.32
WOR and Laboratory		
Rel. Perm.	0.28-0.43	0.35
Transient Test &		
Lab. Rel. Perm.	0.28-0.35	0.31
Log Calculations	0.22-0.50	0.36

Since more than 50% of the observations were in the range of 27% to 35%, it was concluded that the residual oil saturation after waterflooding in the area of the Bingham pilot was 27% to 35%.

Data from the expansion area were examined in the same manner with the exception of the log techniques. It was thought that due to the long history of waterflooding of the Bingham lease, commercial core analyses would give a reasonable approximation of oil saturations. The high produced WOR's in the range of 150 for the pilot wells when first placed on production indicated essentially no mobile oil present at the initiation of the test. Similar data from the expansion area show evidence of higher post-waterflood oil saturations. The values of oil saturations from routine commercial analyses on the three core tests in the expansion area are tabulated as follows: Data are from the middle sand section only.

<u>Well</u>	<u>Sor Range</u>	<u>Average So</u>
109	0.330-0.471	0.374
110	0.287-0.527	0.385
413	0.239-0.419	0.337

A weighted S_{or} average of the three wells in the expansion area of 0.362 was compared to 0.308 for the core wells in the pilot area.

The produced WOR's prior to the formation of the tertiary oil bank were also lower than those observed in the pilot. WOR values generally ranged from 30 to 60 with the average value of the nine confined five-spots (farm A) being 42. This WOR is equivalent to an oil cut of 2% which indicated a limited amount of mobile oil was present in the expansion area prior to initiation of the test. The routine core analyses presented are normally thought to give conservative values of post-waterflood oil saturations because some flushing of the core must have taken place during drilling.

The results of the study in the expansion area are given below:

	<u>S_o Range</u>	<u>Midpoint of Range</u>
Routine Commercial		
Core Analyses	0.24-0.53	0.39
WOR & Lab. Rel.		
Permeability	0.38-0.41	0.40
Transient Test & Lab.Rel.Perm.	0.36-0.43	0.40

Although the midpoint of saturation ranges are very close by all techniques, it is obvious

that there are significant areal differences across the expansion pattern. The data obtained from pressure transient tests should more closely represent the true reservoir conditions in the regions surrounding the test wells. Therefore, the post-waterflood oil saturation was concluded to be in the range of 36% to 43%.

PROJECT DESIGN

Laboratory Studies for Displacing Fluid Design

The micellar solution for the slug used in this test was a surfactant-stabilized dispersion of water in refined hydrocarbon. Marathon developed an initial slug formula in the laboratory which was adjusted for viscosity and mobility control. The high paraffinic Bradford crude and the apparent oil-wet character of the Bradford oil reservoir presented new conditions for the Maraflood process.

Specifications used in the design are as follows: Micellar slugs are formulated which are stable at reservoir temperature and compatible with the reservoir fluids and rock. The selection of a slug and the amount to be injected is based on the oil recovery efficiency of micellar floods in standard Berea cores and on economic considerations.

Slug viscosity, required for stable displacement, is determined by the combined oil and water mobility in the reservoir preceding the slug. The required mobilities are normally calculated from water/oil relative permeability data. However, due to the wettability of the Bradford reservoir, commercial data were not thought to be representative of reservoir performance when flooding with displacing fluids. A special core study was performed to obtain flowing oil and water mobilities for the slug design. The mobility of the oil/water bank flowing ahead of infinite slug injection was measured in Bradford core plugs. The use of Bradford core material simulated the wettability conditions of the reservoir.

The mobility buffer was composed of a water-soluble polyacrylamide polymer, Dow Pusher 500, mixed with fresh injection water. The polymer was selected by flow studies of the buffer solutions in cleaned Bradford core plugs. The buffer was designed to attain mobility control behind the slug without severe permeability loss.

The final slug and polymer design used for the pilot test and for the expansion are covered in the following sections.

Pilot Test

The field testing program began with an inverted five-spot pattern of one new injection well and four new production wells on an 0.75 acre spacing. The pattern was later expanded to 1.5 acres using the old waterflood pattern wells. Figure 2 shows the pilot pattern and pertinent data is summarized in Table 2. Also shown in Figure 2 are the six core tests drilled to evaluate the displacement efficiency of the injected fluids. This method of evaluation was used due to the unconfined nature of the pattern.

A 6% PV slug size was selected for the pilot test. A total of 1,800 barrels of slug were injected into Well 401. The viscosity of the slug averaged 35 cp which was purposely higher than the theoretical design of 25 cp for sufficient mobility control. The higher slug viscosity resulted in lower slug mobility and therefore required a lower mobility buffer solution to protect the slug. The buffer design schedule is shown in Table 2. The polymer used for the mobility buffer was Dow Pusher 500X, which had a lower molecular weight than Pusher 500, and required higher concentrations. Pusher injection was continued until 41,000 barrels were injected, which was then followed by water injection.

The fluid sequence was successfully injected into the Bradford Third Sand reservoir. All producing wells responded to the injection with increased oil cuts and oil production rates. Two wells, 405 and 406, were producing 100 percent water at the initiation of the test, so the appearance of oil in the produced fluids was a positive indication of a tertiary oil bank. Well 403 increased from an oil cut of 7 percent to a peak of 12 percent. The oil cut from Well 404 increased from less than one percent to a peak of 5.5 percent.

When the pilot test was expanded at the end of 1970, the total oil production from the 0.75 acre pattern was 3,500 barrels. Cumulative Pusher injection was 41,011 barrels, equivalent to 1.4 pore volumes, based on the designed pore volume of 29,000 barrels. The effectiveness of the flood was analyzed by: (1) a decline curve extrapolation based on the actual oil production; and (2) data from core tests drilled in the area swept by displacing fluids. Reduced oil saturation shown by core test indicated that the reservoir mainly affected by the process was the middle zone. There were also indications that slug had moved into the tight upper and lower zones in the two nearest core test wells.

To determine by core test the volume of oil displaced, a radial fluid distribution was assumed from injection Well 401. The core tests then represent points of saturation data on either side of a cylinder formed by the circles through each core test (See Figure 2). The reservoir volumes affected and the barrels displaced were based on the saturation determined by commercial core analyses. The specific thickness of the affected reservoir or the average oil saturation remaining in the total zone can be used to calculate the oil remaining upon conclusion of the test.

The minimum amount of oil displaced using core analyses ranged from 2,600 barrels to a maximum of 5,850 barrels based on the most optimistic oil saturations. Table 3 presents displacement efficiencies for the upper and middle zones with assumed reservoir oil saturations of 50% and 40% respectively. This resulted in a displacement efficiency of 57%. The effect of distance from the injection well 401 is illustrated by decreasing displacement efficiency, with increasing radial distance. This incremental displacement of 4,800 barrels compares to an extrapolation of the oil production which indicated an oil displacement of 5,200 barrels.

The reversion to water injection brought an almost immediate decline in oil production from the pilot area which indicated loss of mobility control. In late 1970, four old waterflood wells, two producers and two injectors, were placed on production to expand the pattern to 1.5 acres. It was interesting to observe that only the old production wells (313 and 330) produced oil. The two old water injection wells (0163 and 0164) produced only water for the remainder of the test. The old oil production wells continued on pump for another year, producing an additional 1,000 barrels of oil. Since the oil rates had been steadily declining, the test was terminated. However, the results of the pilot test encouraged the initiation of a large scale project.

Expansion Test

To further evaluate the Maraflood process for tertiary oil recovery and to obtain information on the normal well spacing for the Bradford field, a 46.5 acre expansion test was initiated.

The test utilized the existing waterflood wells and the pattern already developed on the Bingham lease. Therefore, the spacing of approximately 3 acres remained the same as in the previous waterflood. A map of the expanded

test pattern is shown in Figure 3 and pertinent data is given in Table 4. From the pilot test results, it was seen that only a fraction of the reservoir in this area would be effectively flooded by the process. Therefore, the definition of the "effective pore volume" was an important part of the design.

The reservoir rock volume that would be contacted by the injected fluids was determined prior to the initiation of the expanded test. This study resulted in a pore volume design which dictated the amounts of slug and mobility buffer used in the test. It was recognized that although process fluids enter a given vertical section of the reservoir, it does not mean the section will contribute any measurable tertiary oil production. It generally takes a certain pore volume of injection into the interval before a tertiary oil bank will reach the producing well. Unless the oil bank reaches the well, the interval will function as a thief zone and should not be considered as part of the effective pore space.

In the Bingham Expansion area the high permeability region of the Middle zone appears to make up most of the effective pore space being flooded by process fluids. Evidence to this effect in addition to the core data was obtained from (1) Radioactive tracer surveys on selected injection wells, and (2) modeling studies by the "Stiles" method.

From the engineering and geological work done prior to the initiation of slug injection, it was determined that a pore volume of 1,531,000 barrels would be used as a basis to calculate slug and buffer injection volumes. Farm A contained 872,000 barrels of this total and farm B, 659,000 barrels. Approximately 80,000 barrels of slug were injected which was a nominal 5% of the designed pore volume.

The slug viscosity was near the theoretical design value of 25 cp. The mobility buffer was a solution of Dow Pusher 500 polymer. The polymer concentration was tapered according to the schedule shown in Table 4. The pilot test had shown the detrimental effect of reverting to water injection so it was planned to inject at least 100% PV of a polymer solution behind the slug. Consideration is also being given to the maintenance of a minimal polymer concentration in the flood water through the conclusion of the project. The process fluid injectivity and results of the injection are covered in following sections.

FIELD DEVELOPMENT

The 25 existing oil producing wells and 16 water injection wells in the expansion area were reconditioned as follows:

Oil Producing Wells

The casing (6-5/8" O.D.) was replaced and the wells cleaned out to the original total depth. Each well was then shot with from 100 to 140 quarts of liquid explosive to improve the drainage area and remove any debris on the sand face. All producers were equipped with 2-3/8" tubing, a 1-3/4" working barrel, and an electric pumping jack with a cycle timer device. Each producer had an individual flow line (1 1/2" steel) to a central header where each well could be flow-tested and fluid sampled. The oil stock tanks were located in conjunction with the test header facility.

Injection Wells

The original tubing and packer were removed and the wells cleaned out to total depth. The wells were then shot with from 100 to 140 quarts of liquid explosive to improve the well radius and to remove accumulated deposits from long-term water injection. After the wells were cleaned out to total depth, a disc wall packer was run on 2-3/8" seamless tubing and set at the top of the pay sand. Ten sacks of cement were then placed on top of the packer in the annulus between the 2-3/8" tubing and the 6 1/4" bore hole.

Four headers were stratigically located along the main high pressure distribution line (3" steel) so that each injector was connected to the system with individual flow lines. Four injection wells were served at each header installation with an individual meter, cart-ridge-type filter, pressure taps, and fluid volume control coils. Each injection wellhead was equipped with a 2" full-opening valve on the injection tubing to facilitate wireline surveys and with provisions for a meter run.

Pressure Plant and Injection Facilities

The plant for the injection of slug and mobility buffer was equipped with one 600 square foot diatomaceous earth filter, three mixing headers, a mobility buffer mixing unit, two electrically-driven high-pressure triplex pumps, recording pressure gauges, and recording fluid meter facilities.

A tank farm is associated with the plant to provide storage for water, slug components, slug mixing and finished slug, and mobility buffer storage. The tankage used for the storage of finished slug and mobility buffer are lined with epoxy to prevent iron pickup and degradation of the fluids. All low pressure lines from the filter and the mobility buffer mixing unit to the epoxy-lined tanks and to the high pressure pumps are of plastic material. Additional facilities were installed in the plant to provide for pH control and the application of bacteriacides.

PROJECT OPERATIONS AND PERFORMANCE

Fluid Injection

Water injection was initiated into the sixteen injection wells of the Project on January 15, 1971, to provide the opportunity to mechanically test the injection system and to establish a post-waterflood oil production rate and an oil-water cut base prior to the application of the process.

On March 23, 1971, all water injection was terminated in preparation for slug injection. The slug injection progressed in a very stable manner for the period required to inject a total slug volume of 79,990 barrels which was completed in approximately three months. Each injection well received a specific volume of slug as scheduled by the design of the project. The slug was prepared in the self-contained plant which was equipped with mixing and filtration facilities. An on-site laboratory was provided to monitor the quality standard prescribed for this operation, which includes tests for viscosity and the effectiveness of fluid filtration.

Immediately following the slug injection the mobility buffer was injected to protect the trailing edge of the slug. The mobility buffer is mixed continuously using a screw-type feeder which permits control of the polymer concentration and water requirements to prepare a stable polymer solution. The water used to prepare the polymer solution is filtered through a diatomaceous earth filter and is treated with hydrochloric acid for pH control. When the polymer solutions are prepared, they are transported by plastic pipeline and stored in epoxy-lined tanks upstream from the high pressure pump. The quality control tests on the polymer solutions include viscosity, screen factor, and pH values. Currently, the polymer solutions are adjusted to a pH value of 8.0 ± 0.5 to prevent calcium carbonate deposition.

A cartridge-type filter was installed on each injection well to trap any minor gel accumulations that occur during the hydration of the polymer solution. Gels which pass through the injection well filters have caused injectivity problems with time. These problems can be temporarily resolved by using sodium hypochlorite treatments in the individual injection wells to stimulate polymer solution injection. Since these conditions are recurring the treatments must be repeated with time.

Polymer solutions are subject to degradation due to shearing; therefore, the injection rate is regulated with the use of a pressure drop device rather than a valve. This device is made of a 50 foot unit of 3/8" copper tubing placed down-stream from individual well meter. By adding or deleting a 50 foot unit of copper tubing, the fluid distribution to an individual injection well can be effectively controlled.

The less mobile polymer solutions used to provide mobility control tend to restrict injection which extends the operating life of the process. To maintain injectivity, the operating pressure has approached the theoretical critical reservoir pressure. A tracer program was initiated to determine whether pressure parting was occurring and will be covered in the Special Studies section.

In May, 1972, water injection was initiated into the old waterflood injection wells encompassing the test area, in an attempt to confine the process fluids to the test pattern. The effect of this peripheral water injection is shown in Figure 7.

Production

The oil production rate from the 25 producing wells stabilized at 30 barrels per day prior to slug injection. To observe the progress of this test, the total fluid production and oil production rates are monitored continuously. In addition, the produced fluids are analyzed on a monthly basis to determine the concentration of sulfonates and polymers. The chloride concentration in the produced water is monitored on a bi-monthly basis. Figures 5, 6 and 7 show the improvement in oil cut and producing rate along with the chloride concentration for the total project, farm A and farm B.

The first effects of the process were observed from the total project in October, 1971, when the producing rate increased to 48 barrels of oil per day from 32 barrels of oil per day, and the oil cut increased to 2.9% from

1.7%. The peak oil production was 220 barrels per day during August, 1972, and the peak oil cut of 13% was observed in May, 1972.

The oil production from the nine enclosed five-spots (farm A) increased from 18 barrels of oil per day in September, 1971 to 28 barrels of oil per day in October, 1971, and the oil cut increased to 4% from the initial oil cut of 2%. The peak oil production of 130 barrels per day was achieved in May, 1972, along with the maximum oil cut of 19%.

Oil production from the 16 outside producers (farm B) showed an increase in November, 1971, to 28 barrels of oil per day from 19 barrels of oil per day in October, 1971, along with an increase in oil cut of 2.8% from 2%. The peak oil production of 102 barrels of oil per day was reached in August, 1972, however, the peak oil cut of 10.5% occurred in April, 1972.

After peak oil production was attained, the present oil production decline curve closely resembled the previous waterflood performance. The total project has produced 127,000 barrels of oil through December, 1973.

Production Well Stimulation

Since the performance of each producing well is monitored and the fluids sampled for observation, the enclosed five-spots were analyzed individually as the flood progressed. The data assembled indicated by the material balance technique that two producing wells did not perform as effectively as the other wells in the enclosed five-spots. Therefore, during March, 1973, wells 297 and 91 were stimulated with a limited hydraulic fracture treatment consisting of 3,000 gallons of gelled water and 2,000 pounds of 20/40 sand. The effectiveness of this treatment on the productivity from wells 297 and 91 is reflected in the production performance of the total project and farm A as shown in Figures 5 and 6.

SPECIAL STUDIES

Analyses of Produced Fluids

Water samples from each of the producing wells have been analyzed monthly for chlorides, sulfonate and polymer concentration. Crude oil samples were analyzed on a like schedule for sulfonate concentration.

The chloride concentration in the produced water began increasing soon after the initiation of the project. Figures 5, 6, and 7 show the chloride concentration in conjunction with the oil production rate and oil cut versus time for

the total project, farm A and farm B. The increasing chloride concentration associated with the increase in oil production indicates that as the slug is moved through the reservoir, it displaces both connate water and residual oil which was not recovered by the previous waterflood.

The initial chloride concentration from farm A (See Figure 6) was 2,800 ppm in August, 1971, and reached a peak of 5,000 ppm in February, 1972. The peak chloride concentration preceded the peak oil production and began receding prior to the decline in oil production. The total project and farm B exhibited a similar chloride concentration and oil production relationship to that of farm A, the enclosed five-spots.

The relationship between chloride concentration and oil cut from farm A is shown in Figure 8. On a log-log plot, the chloride concentration versus percent oil cut exhibits a straight line function. This performance tends to support the effectiveness of the process to displace from the reservoir both the oil and the water coming in contact with the slug front.

The amount of sulfonate in the oil generally peaked coincident with the peak oil production. However, the sulfonate concentration in the water reached a maximum during the period of declining oil production and increasing water production. The polymer concentrations have been increasing as the oil production continues to decline and as the sulfonate concentrations diminish. An early show of high polymer concentrations caused some concern that there may be pressure parting of the reservoir. However, if there was no parting, these data would tend to indicate some breakdown of the slug bank.

Analytical data taken on fluids produced from the three observation wells is shown in Figures 9, 10, and 11. The data is typical of that observed from other producing wells within the project. The data indicates a broad slug transition zone in the reservoir between the observation and producing wells. It is also possible that the slug is lagging behind in the tighter permeability zones.

Core Test

Core test Well 414 was drilled as an offset to Well 0148 (see Figure 3) in mid-1972. The core analysis results are summarized in Figure 12. A study of the core strengthens the conclusion that the principal pore space being effectively flooded by the process is the high permeability region of the Middle zone known as the Middle-High. In Figure 12, only

the Middle-High region shows evidence of appreciable oil desaturation. Sulfonate traces have been found only in Samples 1824.4 and 1834.3 which are from the Middle section. These data also give added weight to the gamma ray log correlation used to define the reservoir zones.

Tracer Test

The injection of polymer solutions into the Bradford Third Sand reservoir at pressures near formation breakdown led to the testing for the occurrence of fractures. Three wells were chosen for the tracer test: 034, 042, and 0148. (See Figure 3)

The tracers were sodium nitrate (042) and ammonium thiocyanate (034 and 0148) and were injected during the week ending March 14, 1973. The producing wells surrounding these injectors were sampled weekly to determine the presence of tracer ions in the produced fluid. Beginning with April 13th, and ending with May 7, 1973, a positive test for nitrate was determined in the produced water from Well 297, which had recently received a fracture treatment. Since no positive tests for nitrate or thiocyanate were determined at other wells offsetting the test, it is assumed that no serious pressure parting problem exists in the reservoir.

EVALUATION OF TEST

The oil recovery evaluation of the test is based on the performance of farm A which best represents a confined pattern flood.

The farm A production decline curve was extrapolated to an average oil production rate of 1.33 BPD/well resulting in an estimated oil recovery of 130,000 barrels. The decline curve is presented in Figure 13. This recovery is based on extending the test through 1979 to further evaluate the effectiveness of the process. The data derived from the extension of the test will assist in future oil recovery estimates in that it has been rather difficult to determine the oil saturations after waterfloods in the Bradford Third Sand reservoir.

Relating the ultimate oil recovery to post-waterflood oil in place is difficult since estimates must be made for both the effective pore volume and the post-waterflood oil saturation. A range of recoveries expressed as percentages of post-waterflood oil saturation have been calculated for the range of affected pore volumes, based on minimum and maximum oil saturations of 36% and 43%, respectively, and an ultimate oil recovery of 130,000 barrels from farm A.

1. If the original farm A effective pore volume of 872,000 barrels is affected by the process, the ultimate oil recovery will range between 35% and 41% of the oil in place.
2. If only the 16-foot Middle-High zone of farm A with an estimated effective pore volume of 621,000 barrels is affected, the ultimate oil recovery will range between 49% and 58% of the oil in place.

This method of evaluation results in a broad range of recoveries with a minimum of 35% and a maximum of 58%. Indications to date are that a large percentage of the oil is being recovered from the Middle-High zone. Therefore, it is reasonable to assume that the ultimate recovery will be approximately 50% of the oil in place after waterflooding.

Sufficient field data has been gathered to state that:

1. The current extrapolation of five-spot performance in the confined pattern indicates an average of 5,000 barrels of oil per acre can be recovered.
2. A range of oil recovery values from 2,900 to 7,600 barrels per acre can be predicted and will be confirmed later based on actual recovery from individual five-spots within the pattern.
3. The section of the reservoir being most effectively flooded by the process is primarily the Middle-High zone which averages approximately 16 feet in thickness.
4. Analytical data indicate that the micellar slug is no longer a stable bank throughout the reservoir.

ECONOMIC CONSIDERATIONS

The project has demonstrated the effectiveness of the Maraflood process for tertiary oil recovery from a previously waterflooded Bradford Third Sand reservoir.

The design of any future commercial project will be greatly enhanced by the data assembled during the development and operations of this experimental test.

The future of the process will depend largely on the continued high demand for crude

oil in this area and the availability of slug and displacement fluid components at reasonable prices.

This project is economic at the crude oil price as of January 1, 1974.

CONCLUSIONS

1. Oil has been successfully recovered from previously waterflooded Bradford Third Sand by use of the Maraflood process.
2. An estimate of the recoverable oil from the confined portion of the test is 130,000 barrels, if present daily production is extrapolated to 1 BPD per well.
3. The project can be extended through 1979 based on the present evaluation.
4. Present indications are that the ultimate oil recovery will be approximately 50% of the oil in place at the time of the initiation of the project.
5. The process appears capable of recovering an average of 5,000 barrels of oil per acre unit in a confined pattern flood.
6. At the end of the project a range of oil recovery values will be available based on actual recovery from each five-spot in the pattern.
7. The production performance curve for the project to date has closely paralleled the previous waterflood performance.
8. Injectivity is the primary limiting factor in the application of the mobility buffer used in this reservoir due to polymer retention in lower permeability formations.
9. The main zone being effectively flooded by the process is a high permeability section in the middle of the reservoir.
10. Reduced slug costs and improved polymers, together with increased crude oil price, indicate that the Maraflood process will economically recover oil from the Bradford Third Sand reservoir in the Bradford Field.

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IN THE BRADFORD FIELD

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TABLE 1

SUMMARY OF AVERAGE RESERVOIR PROPERTIES
IN BINGHAM TEST AREA

<u>Property</u>	<u>Average Data</u>
Depth - Feet	1,860
Thickness - Feet	23.7
Porosity - Percent	18
Oil Saturation (After Waterflood)	
Pilot Area Range % PV	27 to 35
Expansion Area Range % PV	36 to 43
Permeability - md.	82
Permeability Capacity - Md.Ft.	2,207
Permeability Maximum - md.	311
Permeability Minimum - md.	8.4
Temperature - °F.	68
Oil Viscosity - cp.	5

TABLE 2
BINGHAM PILOT TEST

General Information

Reservoir: Bradford 3rd Sand
 Depth - 1870 feet
 Pore Volume- 29,000 barrels

Pattern: 3/4 Acre Inverted Five-spot
 Wells - 1 injector and 4 producers

Slug Injection:
 Started - 12/5/68
 Injected - 1,844 barrels
 Size - 6.4% PV

Thickened Water Injection:
 Started - 1/19/69

Schedule

<u>Injection</u> <u>bbl.</u>	<u>Concentration</u> <u>ppm</u>	<u>Average Viscosity</u> <u>cp @ 6 rpm & 70°F</u>
1,924	1,700	50
8,558	1,450	38
30,529	1,200	25

Sum thickened water injection - 41,011 barrels

Water Injection:
 Started - 6/25/70

TABLE 3
BINGHAM PILOT TEST
DISPLACEMENT EFFICIENCY
UPPER AND MIDDLE ZONES ONLY

Average S_{o_i} = 50% Upper Zone
 = 40% Middle Zone

<u>Cylinder or</u> <u>Annular Ring</u>	<u>Incremental</u> <u>OIP, bbl</u>	<u>Incremental</u> <u>Oil Disp.</u> <u>bbl.</u>	<u>Incremental</u> <u>% Efficiency</u>	<u>Dist. from</u> <u>Inj. 401</u>
401-407	2090	1990	.95	45' (407)
407-408	1310	967	.74	60' (408)
408-(411/412)	980	426	.43	70' (411/412)
*409-(411/412)	1067	424	.40	80' (409)
*409-410	<u>3004</u>	<u>1006</u>	<u>.33</u>	105' (410)
Totals	8451	4813	.57	

* Middle Zone only affected.

Total P.V. affected = 20,800 bbl.

TABLE 4

BINGHAM EXPANSION TESTGeneral Information

Reservoir: Bradford Third Sand
 Depth - 1866 feet
 Pore Volume - 1.5×10^6 Bbls.

Pattern: 2.9 acre five-spot
 Wells - 16 injectors and 25 producers
 Total Size - 46.5 acres

Injection

Slug Injection:
 Started - 3/23/71
 Injected - 79,990 bbls.
 Size - 5% PV

Mobility Buffer Injection:
 Started - 6/3/71

Polymer Schedule

<u>Injection</u> <u>% PV</u>	<u>Concentration</u> <u>ppm</u>	<u>Average Viscosity</u> <u>cp @ 6 rpm & 70°F</u>
0-2	1,500	50.0
2-20	1,150	35.0
20-26	980	25.0
26-31	900	21.5
31-37	840	19.0
37-43	760	16.5
43-48	700	14.2
48-65	650	12.5
65-71	590	10.7
71-77	540	9.4
77-82	480	8.2

The total thickened water injection was 1,257,000 barrels or 82% PV for the week ending 1/1/74.

Planned Schedule

82-85	480	8.2
85-90	440	7.2
90-95	380	6.2
95-100	350	5.4
100-105	320	4.7
105-110	280	4.1
110-115	255	3.6
115-120	225	3.2
120-125	195	2.8
125	150	2.2

Fig. 1 - Location of Bingham Project within the Bradford Oil Field.

Fig. 2 - Map of Bingham pilot pattern.

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Fig. 3 - Map of Bingham expansion test area.

Fig. 4 - Block diagram of Bingham expansion test.

Fig. 5 - Total project - oil producing rate, oil cut and chloride concentration versus time.

Fig. 6 - Farm A - oil producing rate, oil cut and chloride concentration versus time.

Fig. 7 - Farm B - oil producing rate, oil cut and chloride concentration versus time.

Fig. 8 - Farm A - chloride concentration versus percent oil cut

Fig. 9 - Well 109 - sulfonate in oil and in water and polymer concentration versus time.

Fig. 10 - Well 110 - sulfonate in oil and in water and polymer concentration versus time.

Fig. 11 - Well 413 - sulfonate in oil and in water and polymer concentration versus time.

Fig. 12 - Well 414 - Bingham core test summary.

Fig. 13 - Farm A - production forecast.

APPENDIX B

ANALYSIS OF FALLOFF TEST CONDUCTED IN LAWRY HO-68

(Dated: September 29, 1975)

In July of this year, a pressure falloff test was conducted in the Bradford Third Sand reservoir to determine reservoir characteristics in the vicinity of injection well, Lawry HO-68. This injection well is located within Pennzoil's Lawry lease, McKean County, Pennsylvania, and is to be used in determining the applicability of the Maraflood[™] Oil Recovery Process in low permeability, Penn Grade crude reservoirs. Analyses of the falloff data obtained during this falloff test indicate transmissibility during water injection to be approximately 36 md-ft/cp with a skin factor of about -5.0. These analyses also indicate the presence of a fracture.

Fresh water injection was initiated into Well HO-68 on July 9 at about 42 BPD with a wellhead pressure of 400 spig. This rate was maintained until July 24, at which time the wellhead pressure had increased to 432 psig. On July 24, the water injection was stopped and a 24-hour falloff test was conducted. During this test the pressures were monitored as follows:

- a) Wellhead pressures monitored with a dead weight surface gauge
- b) Bottom-hole pressures monitored by a down-hole gauge
- c) Early wellhead pressures monitored manually by Pennzoil personnel

Because of their greater reliability, the data recorded manually by Pennzoil personnel and bottom-hole gauge were used in this evaluation. Table 1 presents this pressure information.

A type curve (log-log relationship) of Δp versus Δt was utilized to determine the portion of data that could be analyzed to determine valid reservoir characteristics. This relationship is given in Figure 1. Compressive wellbore storage becomes insignificant shortly after water injection stopped. But the .5 slope exhibited on the type curve indicates presence of a fracture. The point in time at which the falloff data is no longer influenced by the fracture system and can be evaluated by normal methods is not clear from this type curve.

A type curve matching technique was therefore utilized to interpret the fall-off data. This type curve matching technique is presented in the July, 1975 issue of Journal of Petroleum Technology in an article entitled "Applied Pressure Analyses for Fractured Wells" by A. C. Gringarten, H. J. Ramey, Jr., and R. Raghaven. Figure 2 gives the match obtained when using an analytical solution using a boundary condition of uniform flux along the vertical fracture. The attempted match using an analytical solution with a boundary condition of an infinite conductive vertical fracture was not satisfactory. Also, Pennzoil personnel indicated that a horizontal fracture was not likely here; therefore, a match using horizontal fracture system was not attempted. The resulting reservoir transmissibility from this analysis was 37.4 md-ft/cp with a skin

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factor between -3.3 and -4.4. Fracture length was determined to be from 69 to 218 feet. The area investigated during this falloff can be estimated from the fracture length approximation and was determined to be from 1 to 12 acres. Table 2 summarizes these results and Table 3 presents the calculations and assumptions utilized for these determinations.

When applying the Horner Plot analysis, care must be exercised to use only the data that represent reservoir characteristics. This portion of the data is usually determined from the type curve plot, but for this test the type curve (presented in Figure 1) is not conclusive as to when these data occur. Therefore the criteria presented in the above cited article were utilized. In the above article, it was stated that the correct semi-log straight line should be achieved by dimensionless time ($t_{D_{xf}}$) = 3 or maybe as

soon as $t_{D_{xf}} = 1$. For this system, the correct semi-log straight line should begin between 3.3 and 10 hours.

Data occurring after 10 hours on the Horner Plot given in Figure 3 were therefore analyzed. The resulting reservoir transmissibility was 34 md-ft/cp with a skin factor from -3.1 to -4.2. These values agree with the parameters determined from the type curve match as compared in Table 2. Calculations and assumptions used in evaluating the Horner Plot are given in Table 3.

Falloff data interpretation by use of the Horner Plot also provides an estimation of the reservoir pressure; for this test the estimation of reservoir pressure was 258 psig. This value agrees quite well with the reservoir pressure of 244 psig which was determined in May, 1975 during a temperature log survey in Well H0-68.

During this 24-hour falloff test, no indication of a reservoir limit was encountered. The area investigated during this 24-hour period can be approximated from the calculated reservoir parameters, although the uncertainty in the system's compressibility prevents a close approximation. Using 1×10^{-5} psi⁻¹ to 1×10^{-6} psi⁻¹ as the upper and lower values for system compressibility, the reservoir volume investigated during the 24-hour period was from 1.9 to 19 acres. These values agree closely with the above limits as determined from the type curve match. Although an indication of what extent this reservoir may be, these calculated limits should be utilized only as lower limits.

TABLE 1
PRESSURE CHANGES DURING
24-HOUR FALLOFF TEST

<u>Shut-In Time</u>		<u>Wellhead Pressure</u>
<u>Hrs.</u>	<u>Min.</u>	<u>psig</u>
	0	432
	1	415
	2	406
	3	397
	4	391
	5	387
	6	383
	7	378
	8	374
	9	371
	10	369
	11	366
	12	362
	13	360
	14	357
	15	355
	16	353
	17	350
	18	348
	19	346
	20	344
	21	342

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<u>Shut-In Time</u>		<u>Wellhead Pressure</u>
<u>Hrs.</u>	<u>Min.</u>	<u>psig</u>
	22	340
	23	338
	24	336
	25	335
	26	333
	27	331
	28	330
	29	328
	30	326
	35	318
	40	312
	45	306
	50	301
	55	296
1	0	292
1	15	279
1	30	268
1	45	258
2	0	249
2	15	241
2	30	234
2	45	227
3	0	220
3	15	213
3	30	207

Appendix B

<u>Shut-In Time</u>		<u>Wellhead Pressure</u>
<u>Hrs.</u>	<u>Min.</u>	<u>psig</u>
3	45	203
4	0	198
4	15	194
4	30	189
4	45	185
5	0	181
5	15	177
5	30	173
5	45	169
6	0	165
9	59	117*
11	30	111*
12	14	105*
12	59	99*
13	44	94*
14	30	90*
15	15	85*
15	59	80*
16	44	75*
17	29	71*
18	14	66*
18	59	63*
19	44	59*
20	29	55*
21	14	52*

Appendix B

<u>Shut-In Time</u>		<u>Wellhead Pressure</u>
<u>Hrs.</u>	<u>Min.</u>	<u>psig</u>
21	59	49*
22	43	44*
24	0	42

* - bottom-hole values corrected to surface values

TABLE 2
SUMMARY OF DATA ANALYSES

	<u>Type Curve Method</u>	<u>Horner Plot Analysis</u>
kh/ μ	37.4 md-ft/cp	34.0 md-ft/cp
Skin Factor	-3.3 to -4.4	-3.1 to -4.2
Volume investigated during 24-hour falloff test	1.2 to 12 acres	1.9 to 19 acres
Estimated reservoir pressure	NA	258 psig
Estimated fracture length	69 to 218 feet	NA

TABLE 3

SUMMARY OF CALCULATIONS
AND ASSUMPTIONS

Assumed Reservoir Parameters:

$$h = 25 \text{ ft.}$$

$$\beta = 1.0 \text{ res. bbl/STB}$$

$$C_t = 1 \times 10^{-5} \text{ to } 1 \times 10^{-6} \text{ psi}^{-1}$$

$$r_w = .67 \text{ ft.}$$

Equations Utilized:

$$P_D = \frac{kh \Delta P}{141.3 q \mu \beta} \quad (1)$$

where:

 P_D = dimensionless pressure k = permeability, md h = thickness, ft ΔP = pressure change, psi q = injection rate, BPD μ = viscosity, cp β = formation volume factor, res. bbl/STB

$$t_{DL} = \frac{.00634 k t}{\phi \mu C_t L^2} \quad (2)$$

where:

 t_{DL} = dimensionless time (for half fracture length) t = time, days ϕ = porosity, fraction C_t = system compressibility, psi^{-1} L = half fracture length, ft.

$$r_w' \approx \frac{L}{2} = r_w e^{-s} \quad (3)$$

Appendix B

where:

s = skin factor

r_w = wellbore radius, ft.

$$kh/\mu = \frac{(162.6) q B}{M} \quad (4)$$

where:

M = slope of semi-log straight line from Horner Plot, psi/cycle

$$s = 1.1513 \left\{ \frac{P_{1hr} - P(\Delta t=0)}{M} - \log \frac{k}{\phi \mu C_t r_w^2} + 3.2275 \right\} \quad (5)$$

where:

P_{1hr} = pressure at 1 hour on semi-log straight line, psi

$P(\Delta t=0)$ = pressure at time of $\Delta t=0$, psi

$$r_d = .03 \sqrt{\frac{kt}{\phi \mu C_t}} \quad (6)$$

where:

r_d = radius of drainage, ft.

t = time, hr.

Utilizing match presented in Figure 2 and equation #1:

$$\frac{kh}{\mu} = \frac{(141.3)(42)(1)(.63)}{100}$$

$$\frac{kh}{u} = 37.4 \text{ md. ft/cp}$$

Applying equation #2 and assuming $C_t = 1 \times 10^{-6} \text{ psi}^{-1}$

$$L^2 = \frac{(.00634)(37.4)(1/24)}{(.11)(25)(10^{-6})(.3)}$$

$$L^2 = 11976 \text{ ft.}^2$$

$$L = 109.4 \text{ ft.}$$

$$\text{Fracture Length} = 2L = 218.8 \text{ ft.}$$

Applying equation #2 and assuming $C_t = 10^{-5} \text{ psi}^{-1}$:

$$L^2 = \frac{(.00634)(37.4)(1/24)}{(.11)(25)(10^{-5})(.3)}$$

$$L^2 = 1197.6 \text{ ft.}^2$$

$$L = 34.6 \text{ ft.}$$

$$\text{Fracture Length} = 2L = 69.2 \text{ ft.}$$

Applying equation #3:

$$e^{-s} = \frac{L}{2r_w} = \frac{109.4}{(2).67}$$

$$s = -4.4$$

$$e^{-s} = \frac{L}{2r_w} = \frac{34.6}{(2).67}$$

$$s = -3.25$$

From match, reservoir extends out at least to reservoir limit to fracture limit ratio of 10/3:

$$x_f = 2L$$

$$x_e = 3.33(2L) = 3.33(2)(109.4)$$

$$x_e = 728.6 \text{ ft.}$$

$$\text{Area Investigated} = x_e^2 = 530,863 \text{ ft.}^2$$

$$\text{Area} = 12 \text{ acres}$$

$$x_e = 3.33 (2) (36.4) = 230.4 \text{ ft.}$$

$$\text{Area Investigated} = (230.4)^2 = 53,100 \text{ ft.}^2$$

$$\text{Area} = 1.2 \text{ acres}$$

Using the semi-log straight line shown in figure 3 and equation #4:

$$\frac{kh}{\mu} = \frac{(162.6)(-42)(1)}{-201}$$

$$\frac{kh}{\mu} = 34.0 \text{ md-ft/cp}$$

Appendix B

Assuming $h = 25$ feet and $C_t = 10^{-6} \text{ psi}^{-1}$ and equation #5:

$$s = 1.1513 \left\{ \frac{321 - 423}{-201} - \log \frac{34}{(.11)(25)(10^{-6})(.67)^2} + 3.2275 \right\}$$

$$\underline{s = -4.2}$$

Assuming $h = 25$ feet and $C_t = 10^{-5} \text{ psi}^{-1}$:

$$s = 1.1513 \left\{ \frac{321 - 423}{-201} - \log \frac{34}{(.11)(25)(10^{-5})(.67)^2} + 3.2275 \right\}$$

$$\underline{s = -3.1}$$

Applying equation #6 to approximate area investigated during 24-hour falloff period and with $C_t = 10^{-6} \text{ psi}^{-1}$:

$$r_d = .03 \sqrt{\frac{(34)(24)}{(.11)(1)10^{-6}(25)}}$$

$$r_d = 516.8 \text{ ft.}$$

$$\text{Area Investigated} = \pi R^2 = \pi (516.8)^2$$

$$\text{Area} = 838,976 \text{ ft.}^2$$

$$\underline{\text{Area} = 19.3 \text{ acres}}$$

$$\text{with } C_t = 10^{-5} \text{ psi}^{-1}$$

$$r_d = .03 \sqrt{\frac{(34)(24)}{(.11)(1)10^{-5}(25)}}$$

$$r_d = 163.4 \text{ ft.}$$

$$\text{Area Investigated} = \pi (163.4)^2$$

$$\text{Area} = 83,897 \text{ ft.}^2$$

$$\underline{\text{Area} = 1.93 \text{ acres}}$$

Utilizing equation #2 to estimate time to reach correct semi-log straight line on Horner Plot:

$$t = \frac{(t_{DL})(\phi)(\mu)(t)(L^2)}{(.00634)k}$$

$$t = \frac{(3)(.11)(1)(25)(10^{-6})(109.4)^2}{(.00634)(37.4)}$$

$$t = .416 \text{ days}$$

$$t = 10 \text{ hours}$$

$$t = \frac{(1)(.11)(1)(25)(10^{-6})(109.4)^2}{(.00634)(37.4)}$$

$$t = 3.33 \text{ hours}$$

Appendix B

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