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BELL CREEK FIELD
MICELLAR-POLYMER PILOT DEMONSTRATION

Third Annual Report
for the Period
October 1978—September 1979

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NOMENCLAURE

bbl	barrel
bpd	barrel per day
$Co^{57,58,60}$	radioactive isotopes of cobalt
EOR	enhanced oil recovery
gpd	gallons per day
h	formation thickness (ft)
H^3	tritium - radioactive isotope of hydrogen
IFT	interfacial tension
k_r	relative permeability
Kw_{ro}	permeability of water at residual oil saturation
K_{air}	absolute permeability
M	thousands
MM	millions
md	millidarcies
meq	milliequivalents
NTA	trisodium salt of nitrilotriacetic acid
NTA-150	40 wt-pct active aqueous solution of NTA
OIP	oil in place
ppm	parts per million
psig	lbs/in^2 gauge
PV	pore volume
ROS	remaining oil saturation at the beginning of MPP water injection
S_{or}	residual-oil saturation
S_{ors}	residual-oil saturation post waterflood at stock tank conditions
STO	stock tank oil
ϕ	porosity (percent or fraction)

CHAPTER I

SUMMARY

Gary Energy Corporation is conducting a DOE Demonstration Pilot to determine if micellar-polymer flooding is an economically feasible technique to enhance oil recovery from the Bell Creek Field, Powder River County, southeastern Montana. The pilot is a contained 40-acre 5-spot located in a representative watered-out portion of Unit 'A' Reservoir. The pay is sandstone with an average net pay of 6.4 feet, air permeability of 1050 md, and water TDS of 4000 ppm. The current average remaining oil saturation in the 40-acre pilot area is estimated to be 28%. The pilot has four injectors (Wells MPP-1, MPP-2, MPP-3, and MPP-4) and one producer (Well 12-1). The overall micellar-polymer oil recovery is estimated at 47% of the remaining oil at the initiation of the micellar-polymer flood.

In the third contract year (October 1978 to September 1979), all tasks including the initiation of soluble oil/micellar injection were completed. Test site development included completion of: (1) radioactive tracer survey and analysis, (2) core analysis, (3) pressure pulse tests and analysis, (4) reservoir description, and (5) test site facilities. Based on test site development data, soluble oil/micellar formulation was finalized and mathematical simulation work by Intercomp completed. The preflush injection phase of the demonstration program was completed, and the soluble oil/micellar injection was initiated at the end of the contract year.

The pilot demonstration project has progressed as scheduled. The time line for the project is shown in Figure 40.

CHAPTER II

INTRODUCTION

Gary Energy Corporation is conducting a DOE cost-shared micellar-polymer pilot demonstration[(1,2,3)]* to determine whether micellar-polymer flooding is a technically and economically feasible technique for enhanced oil recovery at the Bell Creek Field, Powder River County, in southeastern Montana, Figures 1 and 2.

The Bell Creek Field is approximately 15 miles long and 3½ miles wide, and encompasses some 15,000 productive acres developed on 40-acre spacing. The field is described in detail in references 1, 2, 4, and 5.

The pilot is a contained 40-acre 5-spot located in a representative watered-out portion of Unit 'A' Reservoir, Figures 3 and 4. The slight offset of the actual location of the micellar-polymer pilot (MPP) wells from a true square pattern is due to terrain-imposed constraints. The reservoir is sandstone with average properties as follows: net-pay thickness of 6.4 feet, porosity of 29%, permeability (air) of 1050 md, and water TDS of 4000 ppm. The pilot area remaining oil saturation after waterflooding is 28%, and the overall micellar-polymer oil recovery efficiency is estimated at 47% of the waterflood remaining oil.

During the initial design phase of the micellar-polymer pilot, Gary Energy had two processes, one oil-external and one water-external, developed to determine the better performing system for the Bell Creek reservoir.[(6)] Although optimized for the same reservoir rock and fluids, the competing systems were quite dissimilar in chemical composition and slug size so that a "Selection Methodology" was developed as the most cost effective approach to evaluate the two designs.[(2,3,7)] The results of the process selection procedure appeared to indicate that the oil-external Uniflood(TM) process had better performance in the Bell Creek environment. Therefore, Uniflood process was selected for the Bell Creek Pilot.

*Superscript numbers in parentheses are references.

The injection and observation wells were completed in the fall of 1977. Injection plant and associated storage facilities were completed in the Spring of 1978. In the past year, the major effort has been focused on completion of a detailed reservoir description, mathematical simulations, and preflush injection.

Table 1 indicates the tertiary target for waterflood in Unit 'A'. Unit 'A' is approximately one-half of the Bell Creek Field.

CHAPTER III

RELATIVE PERMEABILITY

Water/oil relative permeability tests on cores obtained from Wells MPP-1, MPP-3, MPP-4, and MPP-5 were performed and completed by Core Laboratories, Inc. The cores were mounted in lucite holders and tested with a steady-state method.

Three sets of relative permeability data were reported in the Second Annual Report (October 1977 - September 1978), Ref. 7, for Samples Nos. 4, 7, and 12. Relative permeability data of Sample No. 3 and No. 16 are tabulated in Tables 2 and 3 and plotted in Figures 5 and 6.

Relative permeability data obtained from core tests served as reference data for mathematical simulation studies. These data are also used to supplement pressure-pulse test, tracer test, log data, and other core analysis data for detailed reservoir description.

CHAPTER IV

TEST SITE RESERVOIR DESCRIPTION

A. Pressure Transient Tests and Analyses

The first set of pressure transient tests was conducted during December 1976 between the pilot production wells, Well 12-1, and the corner wells of the containment boundary, Wells 1-15, 6-13, 7-5, and 12-7, Figure 7.[3,4,5] The results of these transient tests showed good pressure response at three of the corner wells, Wells 1-15, 6-13, and 12-7, but a delayed response of much smaller amplitude at Well 7-5. However, based on waterflood production history data, it was thought that continuity had to exist throughout the pilot pattern because of the excellent response of the waterflood in that portion of the field.

After the micellar-polymer pilot infill injection wells were drilled, a second set of pressure transient tests was run in May 1978 between the micellar-polymer pilot (MPP) injection wells and three production wells.[3,7] In each of these tests, the pilot production wells'(Well 12-1, the corner production containment well diagonally opposite the MPP injection well and the other corner production containment well) bottomhole pressures were continuously monitored with downhole Sperry-Sun Pressure Transmission System (PTS) equipment -- e.g. MPP-3 pressure pulse was monitored at 12-1, 7-5, and 12-7, Figure 8. The results of these tests, Figure 9, indicated some sort of geologic anomaly was present between MPP-3 and the pilot production well, Well 12-1.

As a result of the May 1978 pressure transient test series, it was clear that additional information on the extent and exact location of the anomaly was necessary for an adequate reservoir description for the design and numerical simulation of the micellar-flood process and the associated post-test analyses.

Sperry-Sun PTS equipment was installed in the Wells 7-4 and 12-8 in June 1978 and a third series of pressure transient tests were conducted in the quadrant containing MPP-3 by pulsing MPP-3, Figure 10. The result of this test, Figure 11, revealed that the anomaly extended from west of Well 12-8 to south and east of Well 7-4.

The pulse tests conducted during June 1978 were analyzed by means of mathematical simulations. The mathematical model assumed a barrier configuration shown in Figure 12 and a grid system as shown in Figure 13. The observed pulsed pressure responses from Wells 7-4, 7-5, 12-1 and 12-8 were matched very well as shown in Figures 14, 15, 16 and 17 respectively.

B. Tracer Test and Analysis

Radioactive isotopes were injected into the four micellar-polymer pilot injectors on November 21 and 22, 1977. Table 4 lists the tracers and amounts injected into each well. Samples were collected every week from each of the nine producing wells (Pilot Production Well 12-1 sampled twice per week) and analyzed by Eberline Instrument Corporation. These analyses have determined breakthrough times for each tracer to the producing wells, Figure 18.

A streamchannel simulator was used to model the movement of tracers throughout the pattern. The model assumes constant permeability and thickness over the entire study area, but allows for multiple, noncommunicating layers with different permeabilities and thicknesses. The model simulates tracer flow by constructing a series of rectangular cells along each streamline and following the leading and trailing fronts through each cell. The front is the location of the front or rear edge of the tracer slug, assuming no dispersion. Then, at each time frame, the tracer concentration at the end of each streamchannel is calculated by locating the leading and trailing fronts, determining the degree of dispersion of the fronts, and extrapolating the concentration to the production wellbore. The effluent tracer concentration at each production well is then calculated by summing the contributions of all of the streamchannels going into that well.

The input data used in the model are given in Table 5. A single layer, 2.5 feet thick, was picked to represent the reservoir. This was based on some preliminary runs in which simulated peak arrival times matched actual data fairly closely in five out of nine wells for a thickness of 2.5 feet. The values for permeability, porosity, and residual oil saturation were taken from core and log data and from the results of the pressure pulse tests. They are intended to represent the highest permeability sandstone layer in the micellar-polymer pilot area. The well rates used in Cases 1, 2 and 3 (Table 5) are the average daily rates during the tracer study. The daily rates varied somewhat during the tracer study due to well shutdowns and shut in of the pattern for various reservoir tests, so some deviation of actual rates from the constant rates used in the model does occur. The well rates used in Case 4 were based upon the rates set by Intercomp for balanced preflush injection. These well rates were based upon a varying thickness reservoir and therefore do not give a perfectly symmetrical streamchannel pattern using the constant thickness model. The inlet concentrations and total amounts of tracer injected were kept constant for all four cases to make the simulated and measured tracer curves comparable.

Results of Case 3 are reported here. In Case 3, the reservoir boundary was moved so that it cut across the southeast quadrant of the pilot area as shown in Figure 19. The presence of a barrier or discontinuity in the reservoir had been detected by pressure transient tests and by measurements of produced water salinities. For this run, Wells MPP-3, 7-5, and 12-8 were eliminated from the model since they were outside the new reservoir boundary. The total production from this modified pilot area exceeds the total injection, so eight aquifer wells were included to represent water influx from outside the pattern.

The ratios of simulated to actual peak arrival times for Case 3 are tabulated in Table 6.

Some conclusions may be drawn from the tracer test and analysis:

(1) Some type of flow restriction seems to be present between MPP-3 and 12-1 or tracer would have traveled between these wells.

(2) The barrier also helps explain the fast transit times for tracer between MPP-3 and 12-8 and 7-5.

(3) In MPP-1 and MPP-4 there appears to be a directional permeability effect which causes preferential flow of tracer away from the center producer 12-1, and toward the corner wells, 6-13 and 12-7.

C. Geologic Reservoir Models

The results of the pressure transient test and the radioactive tracer survey provided valuable information for the development of geologic reservoir models of the pilot area. Two such models were proposed to describe the pilot area reservoir. The first model, proposed by Union Oil Company, relied primarily on reservoir petrophysical data from cores as well as well logs from the 9 pilot area wells and pressure transient and tracer survey data.* The second model, proposed by Gary Energy Corporation, did not utilize the core trace mineral data but instead emphasized the well logs from 27 wells in the northeast section of Unit 'A', core and log crossplots, production histories and water analyses, as well as the pressure transient and radioactive tracer data. Both models are similar in that each had multiple sand layers and a barrier across the southeast portion of the pilot area.

Due to limits on both time and money, Union's geologic reservoir model was selected and refined. The geologic reservoir model is shown in Figures 20, 21, 22 and 23.

*Union Oil Company, Geological Studies of The Tertiary Pilot Flood Area, Bell Creek Reservoir, E&PP 80-28M, April, 1980.

CHAPTER V

SOLUBLE OIL MICELLAR SYSTEM

A pilot area waterflood commenced in October 1977 to cause the pilot area streamline pattern to be reoriented from a line drive -- used in the field-wide waterflood -- to a 5-spot which is the pattern to be used in the micellar flood. During the extended reservoir description work from October 1977 to December 1978, this pilot area waterflood continued. As a result, the oil saturation in the pilot drainage area was lowered below the typical saturation in Unit 'A' (35%) to possibly as low as the ultimate residual oil saturation to waterflooding (25%) in the preferentially swept regions.

Because this extensive waterflooding -- beyond the ordinary economic limit -- reduced the oil saturation below that for which the original Bell Creek Uniflood(TM) was designed, the Union design group recommended that the soluble oil slug concentration and volume be increased. The new design basis is:

1. Increase the total micellar slug size (soluble oil and micellar water solutions) from 3.0% PV to 3.5% PV. The preliminary design was based upon the premise that the oil saturation in the Bell Creek sand, prior to the start of chemical injection, would be 30 to 35% PV. The best estimate of the oil saturation at the start of the Uniflood application in January 1979 was 25 to 30% PV and Union's design procedures indicated that additional micellar slug was needed to achieve equivalent displacement efficiency.

2. Increase the concentration of the chemicals in the soluble oil (sulfonate and butyl cellosolve) 7% (from 25.16% to 26.92%). This increase is to provide adequate viscosity for the slug under the most unfavorable Bell Creek rock relative permeability conditions shown by the core studies. Union's laboratory floods in stacked Bell Creek core plugs[11] indicated that a 3.5% PV micellar slug with the same surfactant content as the higher pore volume slug used in the Bell Creek core floods was required to obtain the same oil displacement efficiency at the lower values of oil saturation expected to prevail at the start of preflush. Table 7 gives the final Union design for the Bell Creek Pilot.

CHAPTER VI

MATHEMATICAL SIMULATIONS

A. Performance Match for Determining Remaining Oil Saturation

A multiple-layer reservoir prototype was used in a black oil simulator during May 1979 to estimate the magnitude and distribution of remaining oil saturation in the pilot area. The best match of well performance was made using a displaceable oil saturation (ROS minus S_{ors}) of about 13% pore volume at the start of MPP water injection. On the basis of this study, which assumes an average S_{ors} value of 25% pore volume, the 160-acre pilot area is characterized at the start of MPP water injection as follows:

Total Pore Volume:	2,017,000 barrels
Remaining Oil Saturation:	37.9% pore volume
Oil-In-Place:	765 MSTB

The estimated distribution of ROS within the pilot area at the start of MPP injection is described in Table 8; the quadrant definitions are pictorially represented in Figure 24.

The assumption of gravity/capillary equilibrium was used to initially distribute oil in the model. A common oil/water contact was assumed for the three reservoir sands. Capillary pressure curves were calculated and input to the simulator to obtain average saturations at various structural positions required for reproducing observed initial fractional flows in each of the 9 pilot producers.

Eight separate history match attempts were made varying well completion intervals and the position of the oil/water contact at the start of MPP injection. Injection and historical gross fluid withdrawals in each well were specified to match observed oil rate for each producer. The best match for Well 12-1 was obtained using an oil/water contact of 766 feet subsea. Excessive early oil production was computed in each run for 12-1. Thus, the oil production decline curve for Well 12-1, Figure 25, was developed with Intercomp's predicted decline curve[10], which was then used to extrapolate the actual field well test data beyond December 1978. The reason for this was that simulation based recovery curves predicted too high an oil cut for the pilot production well, Well 12-1, in the early portion of the 5-spot production. Thus, the actual well test data for Well 12-1 was used for the early time portion of the 5-spot production curve while maintaining the character of the simulation curve when used to predict the decline past December 1978, giving the curve in Fig. 25.

Waterflood oil recovery from the start of MPP injection to April 1, 1979 was predicted to be 137,500 STB from the 160-acre pilot and surrounding area. This prediction compares to actual production as follows:

Pilot Waterflood Oil Production
From October 1, 1977 - April 1, 1979

(MSTB)

Well #	Actual	Predicted by Simulation
1-15	0	0
1-16	10.0	6.0
6-13	3.5	6.5
12-2	6.5	4.0
12-1	36.0	49.5
7-4	16.1	22.5
12-7	4.6	11.5
12-8	12.9	30.5
7-5	13.6	7.0
	103.0	137.5

The simulated composite oil production is 33% higher than actual composite oil production. The simulated decline curve for Well 12-1 (Figure 25) was adjusted to closely track actual performance. These production results will not support use of the existing reservoir characterization to predict individual well performance and pilot waterflood oil recovery. However, ROS results were judged to be acceptable for establishing initial saturation conditions for use in chemical flood simulations of the central pilot area (Table 9).

B. Preflush Pattern Balance

The term "Pattern Balancing" as used here is the control of fluid flow within the 160-acre micellar/polymer pilot area. The objective of this pattern balancing study is to determine the set of relative well rates which will distribute the alkaline sodium silicate preflush in an optimal manner. An optimal distribution is considered one in which the injected preflush will occupy the same percent of pore volume in each quadrant when the preflush slug is injected into each injection well over the same time period.

The geological reservoir model used in preflush modeling work is a single-layer system, which is essentially the same as that described in the report entitled "Bell Creek Micellar-Polymer Pilot, Remaining Secondary Oil", dated August 1978.[11]

Five cases of pattern balance were studied using Intercomp's BETA II model in a two-dimensional, two-phase mode. Injection and production rates for January 1979 were specified in the model for all active wells which surround the 160-acre pilot area. Figure 13 shows the grid system used in the numerical model and the locations of these active wells. As in previous modeling work on this pilot, heterogeneities were included to represent two distinct geologic facies (barrier bar and lagoonal sediments) and a flow restriction in the southeast quadrant. Physical properties of the two facies are listed in Table 10.

A constant, and therefore areally uniform, reservoir pressure of 1100 psi was specified for the initial condition in the model, and reservoir and fluid properties were scaled to simulate the movement of water soluble preflush through the water-saturated pore volume at a mobility ratio of 0.8. Straight-line relative permeabilities were used with end-points of zero and unity for both saturation, and relative permeability axes. Thus, the respective fluids fractional flows are in proportion to their saturation effectively discounting any relative permeability effects. Each of the variables in the diffusivity constant ($k/\phi\mu c$) was adjusted to simulate single phase water flow in the presence of oil and some gas.

Results of preflush pattern balance simulations are tabulated in Table 11 and shown on Figures 26 through 29. Reservoir heterogeneities in the micellar/polymer pilot area cause each of the four injectors to move fluid to their respective producers at different rates. It will therefore be necessary to match fluid flow rates in each pattern element to the element pore volume during both the preflush and subsequent chemical injection phases of this project to ensure that (1) injected slug size will be about the same percent of pore volume in each element, and (2) all oil banks arrive at the central producer at about the same time. These results also indicate preflush will break through to a majority of the nine pilot producers during the time required to inject 16% of the total pore volume. The injection and production rates outlined in Case 2, Figures 28 and 29, were used as the pattern balance for the preflush.

C. Recovery Predictions for a Repeated Symmetric 5-spot Pattern

The micellar/polymer process in a repeated 5-spot pattern was simulated to estimate the oil recovery for a field expansion, using a streamtube model. Figure 30 shows a sketch of the four streamtubes in one-eighth of a 5-spot pattern. Each streamtube represents a two-dimensional longitudinal and vertical (cross-sectional 3-layer) model with varying width. Properties of the three layers are shown in Table 12.

Four separate simulations were made, one for each streamtube. Oil recovery is obtained by summing the results of the four separate simulations. In the simulations, the mobility ratio was assumed to be unity so each streamtube would receive ¼ of the injected fluids into the 1/8 symmetry element. Thus, each tube was assigned for injection (process design, early 1978) one quarter of (1) 12% of the total pore volume (TPV) of preflush; (2) 3% of the TPV of soluble-oil slug; (3) 60% of the TPV of polymer solution; and (4) 50% TPV plain brine. The amount of injection in each tube is shown in Tables 7 and 13.

Net oil recovery efficiency was determined for each tube equal to oil recovered minus oil injected in the soluble-oil slug, divided by the postwaterflood residual oil in place. The results of simulations are tabulated in Table 14. The 46% recovery is the best estimate of the recovery efficiency using a single sand 3 layer model.

D. Performance Predictions for Pilot Flood

As previously described, there is a flow restriction just north of pilot injection well MPP-3 which effectively prevents direct communication between this injector and the pilot's central producer 12-1. Thus,the important central producer, 12-1, would be receiving flow from only three injection wells, MPP-1, MPP-2, and MPP-4, and the flood pattern would be expected to be highly asymmetric. To determine the reservoir volume being served by each of the injection wells and, hence, determine the appropriate flow rates to ensure that correct volumes of soluble oil and polymer are injected, simulations were made to determine the potential and streamline distributions in the pilot area.

From the streamline distribution (Figure 31), three regions labeled A, B, and C (Figures 31 and 32) were identified. These regions share the common producer 12-1 and are served by injectors MPP-4, MPP-1, and MPP-2, respectively. Figure 33 shows the numerical grid that was developed for the three regions. Using the orthogonal curvilinear coodrinate option in the chemical flood simulator, the y (or ψ) direction was broken into a number of grid elements defined by the boundaries of streamtubes. The x (or Φ) direction was divided to approximately maintain uniform grid spacing down the center of each region. The grid lines generated were close to being orthogonal relative to the streamlines.

Using a uniform porosity of 0.27, Union's total net pay isopach, Figure 20, and the ROS distribution determined during the history match portion of this study, Figure 34, the following pore volumes and oil-in-place at the start of the preflush were determined for the three regions to be simulated with the chemical flood model.

	Region A (bbl)	Region B (bbl)	Region C (bbl)	Total
Pore Volume	256.7M	88.8M	180.3M	525.8M
Fraction of Total Pore Volume	.488	.169	.343	1.00
Oil-in-Place	102.9M	32.3M	49.9M	185.1M
Average ROS	.401	.363	.276	.352

Before proceeding with micellar-polymer flood predictions, the reservoir description and initial conditions were modified somewhat to match oil cut and pressure drop performance observed in the field. By reducing those oil saturations in Region A of .45 to .4 and of .55 to .5 and in Region B from .45 to .4, the oil cut predicted for 12-1 dropped to 0.08, which is close to that observed in the field. In making these changes, the total oil saturation for the central 40 acres (Regions A, B, and C) dropped by less than one saturation percent. The values for average oil saturations and original oil-in-place given in the table in the previous section are based on the modified saturation values. Note that the average saturation for Region C (.275) is thought to be near waterflood residual (0.25), and its initial saturations were not changed when matching total oil cut from 12-1.

Based on micellar-polymer floods run on Bell Creek cores and Bell Creek core relative permeability measurements, Union recommended increasing both the surfactant concentration in the soluble oil slug and the volume of the soluble oil slug.* For the simulations, the alterations were represented by increasing the slug volume sufficiently to account for the total increase in sulfonate injected. This resulted in the simulated injection of a 3.8% pore volume soluble oil slug. The injection schedule thus consisted of 0.16 pore volume (PV) slug of preflush (0.7% active), a .0183 PV soluble oil slug (.5242, .40, .0608, and 0.015 volume fraction water, oil, monosulfonate, and disulfonate, respectively); a .0167 PV micellar water; a 0.6 PV tapered viscosity polymer slug (see schedule in Table); and a 0.4 PV water drive. As described in a previous section, the injectors are expected to go on maximum allowable injection pressure constraint (3200 psi) during the injection of the low-mobility fluids. In the simulations, the switch from rate constraint to injection pressure constraint occurs during polymer injection. As rate constraints cannot be maintained throughout the flood, there is difficulty in satisfying the objective of injecting equal region fractional pore volume per day for the three regions. In the simulations, Region A was chosen for injecting the design process as it was the largest. Times were noted at the end of each phase of the injection schedule as determined from the Region A simulation. These times were then used to control the injection schedules as specified for simulations of Regions B and C.

The results of two-dimensional simulation with barrier are shown in Table 15. To obtain the effect of gravity segregation and vertical dispersion, recourse was made to earlier work,[9] which indicated a vertical sweep of 0.85. Figure 35 shows the cumulative oil recovery curve for the pilot. The non-incremental production is the data taken from the decline curve of Figure 25. The 3-dimensional recovery efficiency at Well 12-1 for the chemical flood for the barrier model would be .85 x .55 = .47, a value remarkably close to that calculated above for the one-eighth of a symmetric 5-spot with similar rock/fluid properties.

The projection of the chemical flood incremental production on Figure 35 as a function of PV injected was derived from Intercomp's final report on Reservoir Characterization and Prediction of Chemical Flood Performance[12]. The total chemical flood incremental production is estimated to be: 101,000 x .85 = 85,000.

*See Chapter V.

Figure 34 shows the initial ROS distribution at start of preflush injection. Figures 36 to 39 show the computer predicted location of the iso-S_{or} contours for the following injected % PV values from start of preflush injection:

Design Injection Days	Design %PV Injected Starting with Preflush
0	0
135	17
232	30
478	62
end	104

Figure 35 shows the composite cumulative production at Well 12-1, and Figures 36 to 39 show the corresponding reduction in S_{or} values across the pattern as the chemical flood proceeds.

CHAPTER VII

FIELD DEMONSTRATION PROGRAM

A. Preflush

Preflush injection commenced on February 5, 1979 and was completed after 145 days on July 1, 1979. The injection and production rates given in Table 16 were maintained throughout the preflush injection period. Severe spring storms caused a few days of down time due to field-wide electrical outages, but otherwise the preflush phase proceeded without incident. The preflush was 16% PV and consisted of caustic soda (50 wt% active) 0.661 vol% and sodium silicate (37.6 wt% active) 0.520 vol% in softened Madison water.

B. Soluble Oil Slug

Soluble oil injection commenced on August 20, 1979 and was completed on October 8, 1979. The time window between July 1 and August 20 was due to the sequencing requirements of reservoir diagnostics and also to sulfonate production difficulties. The soluble oil pattern balance and design chemical usage is given in Table 17.

Table 18 is the soluble oil blend make-up and daily injection log. The fact that (1) there were 6 different soluble oil blends required due to variations in the sulfonate blend delivered and (2) that on some days there was no soluble oil injection due to delays in field deliveries of the sulfonate blend, indicates that some difficulties were encountered during the sulfonate production and delivery which impacted the soluble oil injection phase.

The actual soluble oil make-up varied somewhat as shown in Table 18 due to slight variations in the molecular distributions in the six sulfonate blend production batches used during the soluble oil injection. However, the two-phase envelope of the soluble oil ternary phase diagram was functionally below the anhydrous soluble oil/micellar water traverse line across the phase diagram. Total injection for the anhydrous soluble oil was 1.83% PV alternated daily with micellar water with 1.67% PV injection.

C. Polymer Injection

The viscosity design specification for the Nal-Flo F polymer was 92 cp (68^{O}F) and 76 cp (110^{O}F) at 1250 ppm 100% active concentration. Polymer injection began October 14, 1979.

Table 19 gives the polymer injection design.

CHAPTER VIII

DECISION POINTS, WORK FORECAST AND TIME LINE

Reservoir definition work was completed with the tracer survey, pressure pulse-test analysis and numerical simulation work. This effort leads to Decision Point 3, "Site, Configuration and Pattern Confirmation", Table 20. The purpose of Decision Point 3 is to indicate that the reservoir-site description (ϕ, h, k and S_{or} as functions of reservoir location) is sufficiently accurate to lend confidence in the design and interpretation of the pilot performance.

Decision Point 4, "Determination Pilot Test Project Confirmation", is based upon engineering and numerical simulation work, which in turn has as input the work in Decision Points 2 and 3. Decision Point 4 is where all previous work comes to a focus for the "Go/No Go" decision with respect to the recommendation for injection of the chemical flood system. Decision Point 4 requires that there be reasonable confidence in four factors: (1) in the description of the site characteristics; (2) in the understanding of the operative micellar-polymer mechanism as indicated by the ability to simulate the core flood test; (3) in the related simulation of the pilot behavior and performance; and (4) in the expected level of the pilot recovery.

Decision Points 3 and 4 were passed upon affirmatively by the Working Interest Owners Technical Committee and Department of Energy Technical Project Officer on May 24, 1979. Micellar/soluble oil slug injection began August 20, 1979.

The Time Line for the Project is given in Figure 40, the Milestone Chart in Table 21.

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3. Goldburg, A. Haddenhorst, F., Johnson, G., and Stevens, P., "Micellar-Polymer Oil Recovery Demonstration in the Bell Creek Field, Montana" , Paper A-2, Vol. 1, Proceedings, 4th ERDA Symposium on Enhanced Oil and Gas Recovery, Tulsa, August 1978.

4. Gary Operating Company, "Bell Creek Field Micellar-Polymer Pilot Demonstration", First Annual Report, July 1976 - September 1977, BERC/TPR-77/13.

5. Vargo, J. J., "Site Selection, Reservoir Definition and Estimation of Tertiary Target Oil for the Bell Creek Unit 'A' Micellar-Polymer Project", SPE-7-72.

6. Goldburg, A., "Selection Methodology as Between Competing Micellar-Polymer Designs", SPE 6729.

7. Gary Operating Company, "Bell Creek Field Micellar-Polymer Pilot Demonstration", Second Annual Report, October 1977 - September 1978, BETC-1802-27.

8. Dietrich, J., "Bell Creek Micellar/Polymer Pilot Pattern Balancing During Preflush Injection", Intercomp Technical Report, January 1979.

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10. Intercomp, "Bell Creek Micellar/Polymer Pilot Remaining Secondary Oil", August 1978.

11. Union Oil Company, "Results of Application of the Uniflood Process in Berea and Bell Creek Sandstone Cores of Various Lengths", March 1978.

12. Intercomp, "Bell Creek Micellar/Polymer Pilot, Reservoir Characterization and Prediction of Chemical Flood Performance", July 1979.

TABLE 1

TERTIARY TARGET OIL

Bell Creek Field

Waterflood Unit 'A'

	bbl
Original Oil in Place	122,000,000
Cumulative Production (10-1-79)	55,581,000
Secondary Reserves	6,678,000
Ultimate Primary plus Secondary	62,259,000
Oil Remaining after Waterflood	59,741,000

TABLE 2

STEADY-STATE WATER-OIL RELATIVE PERMEABILITY DATA

Sample Number: 3 (MPP-1)

Air Permeability, md: 2450

Oil Permeability at Initial Water Saturation, md: 1590

Initial Water Saturation, Percent Pore Space: 16.2

Porosity, Percent: 34.3

Water Saturation Percent Pore Space	Water-Oil Relative Permeability Ratio	Relative Permeability to Water*, Fraction	Relative Permeability to Oil*, Fraction
	Water Saturation Increasing		
16.2	--	0.000	1.000
50.7	0.069	0.013	0.182
53.6	0.137	0.015	0.108
56.9	0.691	0.036	0.053
59.3	3.47	0.055	0.016
59.9	7.09	0.055	0.0078
68.0	--	0.155	--
	Water Saturation Decreasing		
60.5	7.07	0.041	0.0058
56.2	3.50	0.034	0.0096
50.4	0.753	0.030	0.040
48.9	0.149	0.014	0.096
46.8	0.074	0.0090	0.121
31.9	--	--	0.333

*Relative to oil permeability

TABLE 3

STEADY-STATE WATER-OIL RELATIVE PERMEABILITY DATA

Sample Number: 16 (MPP-5)

Air Permeability, md: 500

Oil Permeability at Initial Water Saturation, md: 162

Initial Water Saturation, Percent Pore Space: 41.2

Porosity, Percent: 31.3

Water Saturation Percent Pore Space	Water-Oil Relative Permeability Ratio	Relative Permeability To Water*, Fraction	Relative Permeability to Oil*, Fraction
	Water Saturation Increasing		
41.2	--	0.000	1.000
59.6	0.072	0.011	0.154
62.7	0.144	0.017	0.121
64.8	0.716	0.032	0.044
65.4	3.57	0.057	0.016
66.0	7.45	0.069	0.0092
72.2	--	0.515	--
	Water Saturation Decreasing		
66.1	7.24	0.098	0.014
65.1	3.63	0.061	0.017
63.1	0.702	0.029	0.041
60.2	0.139	0.013	0.092
57.3	0.072	0.0099	0.137
41.9	--	--	0.931

*Relative to oil permeability

TABLE 4

RADIOACTIVE TRACERS
AND AMOUNTS USED FOR TRACER SURVEY

WELL	TRACER	AMOUNT INJECTED
MPP-1	H^3	20 curies
MPP-2	Co^{60}	50 millicuries
MPP-3	Co^{58}	100 millicuries
MPP-4	Co^{57}	25 millicuries

TABLE 5

MODEL INPUT PARAMETERS

Values common to all cases:

Porosity, ϕ = 0.30

Immobile Oil Saturation, %PV = 30

Coefficient of Longitudinal Mixing, ft. = 12.6

Molecular Diffusion Coefficient, ft^2/day = 0.04

Number of Layers = 1

Reservoir Thickness, ft. = 2.5

Effective Permeability, md = 215

Length of Stream Channel Cells, ft = 16

Water Viscosity at Reservoir Conditions, cp = 0.65

Values which change for different cases:

	Well Flowrates, bbl/Day (- = Injection, + = Production)			
	Case 1	Case 2	Case 3	Case 4
Injection Wells				
MPP-1	-869	-869	-869	-531
MPP-2	-858	-858	-858	-1000
MPP-3	-869	-869	not modeled	not modeled
MPP-4	-867	-867	-867	-762
Production Wells				
1-15	308	308	308	250
1-16	557	557	557	383
6-13	315	315	315	133
12-2	252	252	252	440
12-1	990	990	990	668
7-4	318	318	318	227
12-7	369	369	369	190
12-8	250	250	not modeled	not modeled
7-5	318	318	not modeled	not modeled
Total Production	3677	3677	3109	2291
Total Injection	-3463	-3463	-2594	-2293
Net Production	214	214	515	-2

TABLE 6

PEAK TRACER CONCENTRATION ARRIVAL TIMES
(Simulated ÷ Actual)

Injection Well	to	Production Wells		
MPP-1	1-16	6-13	7-4	12-1
	1.2	1.3	<.4	.94
MPP-2	1-15	1-16	12-1	12-2
	<1.0	.90	.78	-
MPP-3	12-1	7-4	7-5	12-8
	-	-	Not Simulated	Not Simulated
MPP-4	12-2	12-1	12-8	12-7
	.99	.83	-	2.1

TABLE 7

FINAL PROCESS DESIGN FOR BELL CREEK PILOT

Pilot Area Pore Volume = 2,200,000 bbl

PREFLUSH:	16% PV	
	Caustic Soda (50 wt% active)	0.661 vol%
	Sodium Silicate (37.6 wt% active)	0.520 vol%
SOLUBLE OIL:	1.83% PV	
	Bell Creek Crude Oil	60.7 vol%
	*Petroleum Sulfonate Blend (45.7 wt% active)	32.3 vol%
	Napthalite	7.0 vol%
MICELLAR WATER:	1.67% PV	
	NTA-150 (40 wt% active)	0.95 vol%
POLYMER:	100% PV	

Graded Slug Design Assuming 100% active Polymer

4% PV	1250 ppm
6% PV	1150 ppm
8% PV	975 ppm
15% PV	850 ppm
10% PV	750 ppm
7% PV	600 ppm
5% PV	400 ppm
5% PV	250 ppm
40% PV	50 ppm

*Petroleum Sulfonate Blend Formulation

	wt%
Petrostep(TM) 500	21%
Petrostep 465	51%
Petrostep 420	7%
Butylcellosolve	6%
Water	15%
	100%

TABLE 8

BELL CREEK MICELLAR/POLYMER PILOT
160-ACRE PILOT AREA
REMAINING OIL SATURATION (ROS)
AT THE START OF MPP WATER INJECTION*

40-Acre Quadrant (or Fractional Quadrant)	Pore Volume (Mbbls)	Oil-in-Place At Start MPP Injection (MSTB)	Waterflood Residual Oil** (MSTB)	Waterflood Movable Oil*** (MSTB)	Average Remaining Oil Saturation At Start MPP Injection (Fraction of Pore Volume)
MPP-1	305	129	76	53	0.423
MPP-2	866	238	216	22	0.275
MPP-3 (downdip of barrier)	134	86	34	52	0.642
MPP-3 (updip of barrier)	158	68	40	28	0.430
MPP-4 (downdip or NW of barrier)	554	244	138	106	0.440
TOTALS(160-ac.)	2.017	765	504	261	0.379

*Start of MPP injection was October 1, 1977
**Using swept-zone residual oil saturation of 25% pore volume
***Theoretically recoverable oil from waterflooding with 100% volumetric sweep and capture efficiencies

TABLE 9

BELL CREEK MICELLAR/POLYMER PILOT 160-ACRE PILOT AREA
SIMULATED VERSUS ACTUAL REMAINING OIL SATURATION (ROS)
AS OF APRIL 1, 1979

40-Acre Quadrant (or Fractional Quadrant	Fractional Wells in Each Quadrant	Actual Cum. Oil (STB)	Simulated Cum. Oil (STB)	Actual Secondary Production* (Fraction of Pore Vol.)	Simulated Secondary Production (Fraction of Pore Vol.)	Actual Average Remaining Oil Saturation As of 4/1/79 (Fraction of Pore Vol.)	Simulated Average Remaining Oil Saturation As of 4/1/79 (Fraction of Pore Vol.)
MPP-1	1/2(1-16),3/8(12-1), (6-13),3/4(7-4)	20,500	26,900	0.067	0.088	0.356	0.335
MPP-2	1/2(1-16),1/8(12-1), 1/2(12-2)	7,700	6,700	0.009	0.008	0.266	0.267
MPP-3 (downdip of barrier)	1/4(7-4),1/8(12-1)	5,100	7,100	0.038	0.053	0.604	0.589
MPP-3 (updip of barrier)	3/4(12-8),(7-5)	14,000	17,900	0.089	0.113	0.341	0.317
MPP-4 (downdip or NW of barrier)	1/4(12-8),1/2(12-2) 3/8(12-1)(12-7)	14,800	23,800	0.027	0.043	0.413	0.397
TOTALS (160 Acres)		62,100	82,400	0.031	0.041	0.348	0.338

*Production during the period October 1, 1977 to April 1, 1979 and 60% from 160-acre pilot area.

TABLE 10

PHYSICAL PROPERTIES OF THE TWO GEOLOGIC FACIES
FOR PREFLUSH SIMULATIONS

	Barrier Bar	Lagoonal Sediments
Water viscosity, cp	0.56	0.56
Preflush viscosity, cp	0.70	0.70
Effective water porosity, %	21	18
Effective compressibility, psi^{-1}	30×10^{-6}	30×10^{-6}
Effective water permeability, md	k_x = 325	k_x = 65
	k_y = 168	k_y = 56

TABLE 11

BELL CREEK MICELLAR/POLYMER PILOT
PREFLUSH PATTERN BALANCE STUDY
JANUARY 18, 1979

QUADRANTS	160-ACRE QUADRANT PORE VOLUMES (Mbbl)	(%)	40-ACRE QUADRANT PORE VOLUMES (Mbbl)	(%)	40-ACRE PREFLUSH IN QUADRANT PORE VOLUMES AFTER 130 DAYS OF INJECTION: CASE 1 CURRENT UNBALANCED WELL RATES (Mbbls. Preflush)	(% PV Contacted)	CASE 2 SYMMETRICALLY BALANCED WELL RATES (Mbbls Preflush)	(% PV Contacted)	CASE 3 ASYMMETRICALLY BALANCED WELL RATES WITH MODERATE OFFTAKE RATE IN NO. 12-1 (Mbbls. Preflush	(% PV Contacted)	CASE 4 ASYMMETRICALLY BALANCED WELL RATES WITH HIGH OFFTAKE RATE IN NO. 12-1 (Mbbls. Preflush)	(% PV Contacted)	SCALED MPP INJECTION AND ALL SIDE WELLS SHUT-IN (Mbbls. Preflush)	(% PV Contacted)
MPP#1	433	20.0	160	23.0	46	29	22	14	38	24	38	24	43	27
MPP#2	812	37.5	245	35.0	39	16	35	14	34	14	38	16	35	14
MPP#3	303	14.0	119	17.0	2	2	1	1	1	1	2	2	2	2
MPP#4	617	28.5	177	25.0	40	23	27	15	21	15	31	18	29	16
AVERAGES						18		12		14		16		16
TOTALS	2165	100.0	701	100.0	127		85		99		109		109	

TABLE 12

THREE-LAYER VERTICAL CROSS-SECTION OF TUBES

$h = 2.5'$	$k_h = 1750$ md	$k_v = 350$ md
$h = 1.5'$	$k_h = 750$ md	$k_v = 75$ md
$h = 1.0'$	$k_h = 400$ md	$k_v = 20$ md

$\bar{k}_h = 1180$ md

$\phi = .273$

$S_{orw} = 0.25$

TABLE 13

PERCENT TUBE PORE VOLUME INJECTED

	Percent TPV	Preflush	Soluble Oil	Polymer	Chase Brine
Tube 1	18	16	4.1	83	69
Tube 2	20	15	3.8	77	64
Tube 3	24	13	3.0	63	53
Tube 4	38	8	2.0	39	33

TABLE 14

OIL RECOVERY FROM STREAM TUBE SIMULATIONS

	Percent TPV	Oil Recovery Efficiency	Tube-Volume Weighted Recovery
Tube 1	18	65%	11.7
Tube 2	20	62%	12.4
Tube 3	24	52%	12.5
Tube 4	38	26%	9.9
		Total Weighted Recovery =	46.5

TABLE 15

RUN SUMMARY
PREDICTED OIL RECOVERY FOR CENTRAL PILOT PRODUCER, 12-1

Areal Two-Dimensional

Data Set	Percent Original Oil-in-Place Region A	Region B	Region C	Composite	Mbbls Composite
*SJS	57%	56%	50%	55%	101.

*Computer run carried out at Atlantic Richfield Research Center, Plano, Texas by S. J. Salter.

TABLE 16

PREFLUSH PATTERN BALANCE

PRODUCTION WELL	RATE (bpd)
1-15	250
1-16	383
6-13	133
7-4	227
7-5	94
12-1	668
12-2	440
12-7	190
12-8	285
	2,670

INJECTION WELL	RATE (bpd)
MPP-1	531
MPP-2	1,000
MPP-3	377
MPP-4	762
	2,670

145 days to inject 16% P.V. Preflush

TABLE 17

SOLUBLE OIL MAKE-UP

PRODUCTION	bpd
1-15	145
1-16	229
6-13	86
7-4	120
7-5	60
12-1*	485
12-2	302
12-7	158
12-8	116
	1701

INJECTION	bpd
MPP-1	339
MPP-2	578
MPP-3	153
MPP-4	631
	1701

*Pilot 5-spot producing well

CHEMICAL USAGE

Crude Oil	541 bpd	NTA 325.4 gpd
Sulfonates	288 bpd	
Napthalite	62 bpd	
Anhydrous Soluble Oil	891 bpd	Injected on Alternate Days
Micellar Water (Softened Madison)	810 bpd	
Total	1701 bpd	

TABLE 18

BELL CREEK MICELLAR-POLYMER PILOT PROJECT

Summary of Actual Soluble Oil and Micellar Water Injection
August, September, October, 1979

Date	Soluble Oil Volume Injected (bpd)	Blend No.	% Sulfonate In Blend	% Napthalite In Blend	% Crude In Blend	Micellar Water Volume Injected (bpd)	Micellar Water Cl^- (ppm)	Micellar Water NTA Vol.%
08-20-79	890	1	32.2	10.2	57.6	810	1274	1.32
08-21-79	891	1	32.2	10.2	57.6	810	1033	1.26
08-22-79	891	1	32.2	10.2	57.6	810	1026	1.27
08-23-79	891	1	32.2	10.2	57.6	810	1213	1.35
08-24-79	891	1	32.2	10.2	57.6	810	1086	1.35
08-25-79	891	1	32.2	10.2	57.6	810	1309	1.33
08-26-79	891	1	32.2	10.2	57.6	810	1032	1.27
08-27-79	891	2	32.2	10.2	57.6	810	1050	1.25
08-28-79	891	2	32.2	10.2	57.6	810	1333	1.27
08-29-79	891	2	32.2	10.2	57.6	810	1074	1.23
08-30-79	891	2	32.2	10.2	57.6	810	1091	1.29
08-31-79	891	2	32.2	10.2	57.6	810	1109	1.26
09-01-79	891	2	32.2	10.2	57.6	810	1027	1.25
09-02-79	891	2	32.2	10.2	57.6	810	1080	1.26
09-03-79	891	2	32.2	10.2	57.6	810	1074	1.27
09-04-79	891	2	32.2	10.2	57.6	810	991	1.23
09-05-79	891	2	32.2	10.2	57.6	810	584	1.27
09-06-79	891	2A	36.0	9.6	54.4	810	448	1.25
09-07-79	891	2A	36.0	9.6	54.4	810	519	1.27
09-08-79	891	3	39.2	9.1	51.7	810	549	1.32
09-09-79	891	3	39.2	9.1	51.7	810	454	1.35
09-10-79	891	3	39.2	9.1	51.7	810	472	1.31
09-11-79	891	3	39.2	9.1	51.7	810	460	1.29
09-12-79	891	3	39.2	9.1	51.7	810	460	1.29
09-13-79	No Soluble Oil Injection Due to Lack of Sulfonate							
09-14-79	No Soluble Oil Injection Due to Lack of Sulfonate					810	472	1.22
09-15-79	891	4	39.2	3.6	57.2	810	59	1.29
09-16-79	891	4	39.2	3.6	57.2	810	59	1.25
09-17-79	891	5	32.2	10.2	57.6	810	513	1.23
09-18-79	891	5	32.2	10.2	57.6	810	513	1.29
09-19-79	891	5	32.2	10.2	57.6	810	47	1.26

BELL CREEK MICELLAR-POLYMER PILOT PROJECT

Summary of Actual Soluble Oil and Micellar Water Injection
August, September, October, 1979

Date	Soluble Oil Volume Injected (bpd)	Blend No.	% Sulfonate In Blend	% Napthalite In Blend	% Crude In Blend	Micellar Water Volume Injected (bpd)	Micellar Water Cl^- (ppm)	Micellar Water NTA Vol. %
09-20-79	891	4	39.2	3.6	57.2	875	53	1.28
09-21-79	No Soluble Oil Injection Due to Lack of Sulfonate					810	53	1.26
09-22-79	891	4	39.2	3.6	57.2	810	47	1.31
09-23-79	891	4	39.2	3.6	57.2	810	59	1.29
09-24-79	No Soluble Oil Injection Due to Lack of Sulfonate							
09-25-79	891	4	39.2	3.6	57.2	810	47	1.27
09-26-79	891	4	39.2	3.6	57.2	810	59	1.27
09-27-79	891	4	39.2	3.6	57.2	810	59	1.30
09-28-79	891	4	39.2	3.6	57.2	810	53	1.28
09-29-79	891	4	39.2	3.6	57.2	810	65	1.29
09-30-79	891	6	32.2	10.2	57.6	1208	448	1.33
10-01-79	No Soluble Oil Injection Due to Lack of Sulfonate							
10-02-79	891	6	32.2	10.2	57.6	810	560	1.24
10-03-79	891	6	32.2	10.2	57.6	810	519	1.29
10-04-79	891	6	32.2	10.2	57.6	810	443	1.24
10-05-79	891	6	32.2	10.2	57.6	810	472	1.25
10-06-79	891	6	32.2	10.2	57.6	810	47	1.20
10-07-79	891	6	32.2	10.2	57.6	810	41	1.22
10-08-79	651	6	32.2	10.2	57.6	1700	41	1.1
10-09-79	0	0	0	0	0	1700	45	.81
10-10-79	0	0	0	0	0	1700	106	.2

Polymer injection started at this point

TABLE 19

Graded Polymer Slug Design

PILOT AREA PORE VOLUME = 2,200,000 bbl

	bbl	lb/bbl Water	lb water	Polymer 30% Active ppm	lb 30% Active* Polymer
4% Pore Volume	88,000	350	30,800,000	4167	128,333
6% Pore Volume	132,000	350	46,200,000	3833	177,100
8% Pore Volume	176,000	350	61,600,000	3250	200,200
15% Pore Volume	330,000	350	115,500,000	2833	327,250
10% Pore Volume	220,000	350	77,000,000	2500	192,500
7% Pore Volume	154,000	350	53,900,000	2000	107,800
5% Pore Volume	110,000	350	38,500,000	1333	51,333
5% Pore Volume	110,000	350	38,500,000	833	32,082
40% Pore Volume	880,000	350	308,000,000	167	51,333

Total Pounds 30% Active Polymer = 1,261,516

*30% active

$$\frac{\text{ppm}}{1 \times 10^6} \times \text{lb} = \text{lb 30\% active polymer}$$

TABLE 20

BELL CREEK MICELLAR-POLYMER DEMONSTRATION-PILOT
DECISION POINTS

Decision Point	Title	Date
1	Site Selection	10/76 (passed)
2	Fluid System Selection	8/77 (passed)
3	Site, Configuration and Pattern Confirmation	5/79 (passed)
4	Pilot Test Project Confirmation	5/79 (passed)
5	Fluid Plant Operational	5/78 (passed)

TABLE 21

MILESTONE CHART

1503:	Field Testing and Tracer Injection	12/78
1504:	Site Characterization and Confirmation Studies	12/78
1600:	Site Confirmation (Decision Pt. 3)	2/79
1702:	Test Design and Forecast	1/79
1800:	Study of Numerical Simulation Results	1/79
1900:	Project Confirmation (Decision Pt. 4)	2/79
2401:	Acq., Q.Cl & Inj. of Preflush w/Tracer	1/79-6/79
2402:	Acq., Q.C. & Inj. of Micellar	8/79-10/79
2403:	Acq., Q.C. & Inj. of Polymer	10/79-6/81
2404:	Acq., Q.C. & Inj. of Drive Water	7/81-6/82
2600:	Production Monitoring, Analysis & Reporting	1/79-6/81
2604:	Monitoring of Oil Bank & Production Well (Peak)	4/80-8/80
2800:	Simulator Predictions	5/79-11/79
2801:	Pilot Course Corrections	8/79
2900:	Simulator Performance Matching to Production Well	2/80-7/80
3000:	Compilation of Results	1/79-6/81
3101:	Technical Analysis	3/79-6/81
3102:	Economic Analysis	4/80-6/81
4100:	Recommendation for Expansion to Commercial Scale	3/81
5000:	Final Report	7/80-6/81

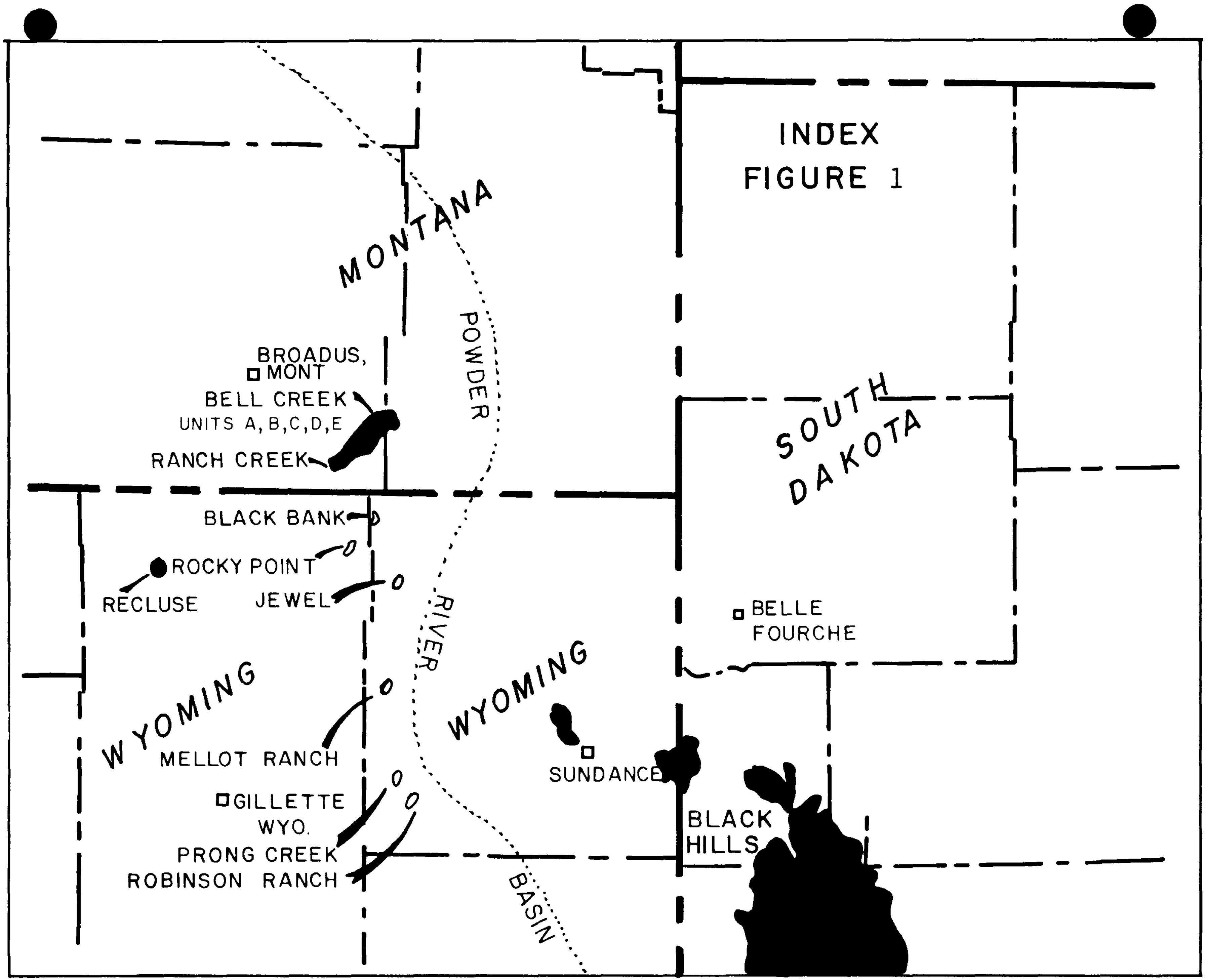
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FIGURE 1
MONTANA
POWDER
RIVER
BASIN
BROADUS,
MONT
BELL CREEK
UNITS A, B, C, D, E
RANCH CREEK
BLACK BANK
ROCKY POINT
RECLUSE
JEWEL
WYOMING
MELLOT RANCH
GILLETTE
WYO.
PRONG CREEK
ROBINSON RANCH
WYOMING
SUNDANCE
BLACK
HILLS
SOUTH
DAKOTA
BELLE
FOURCHE

FIGURE 1

FIGURE 2

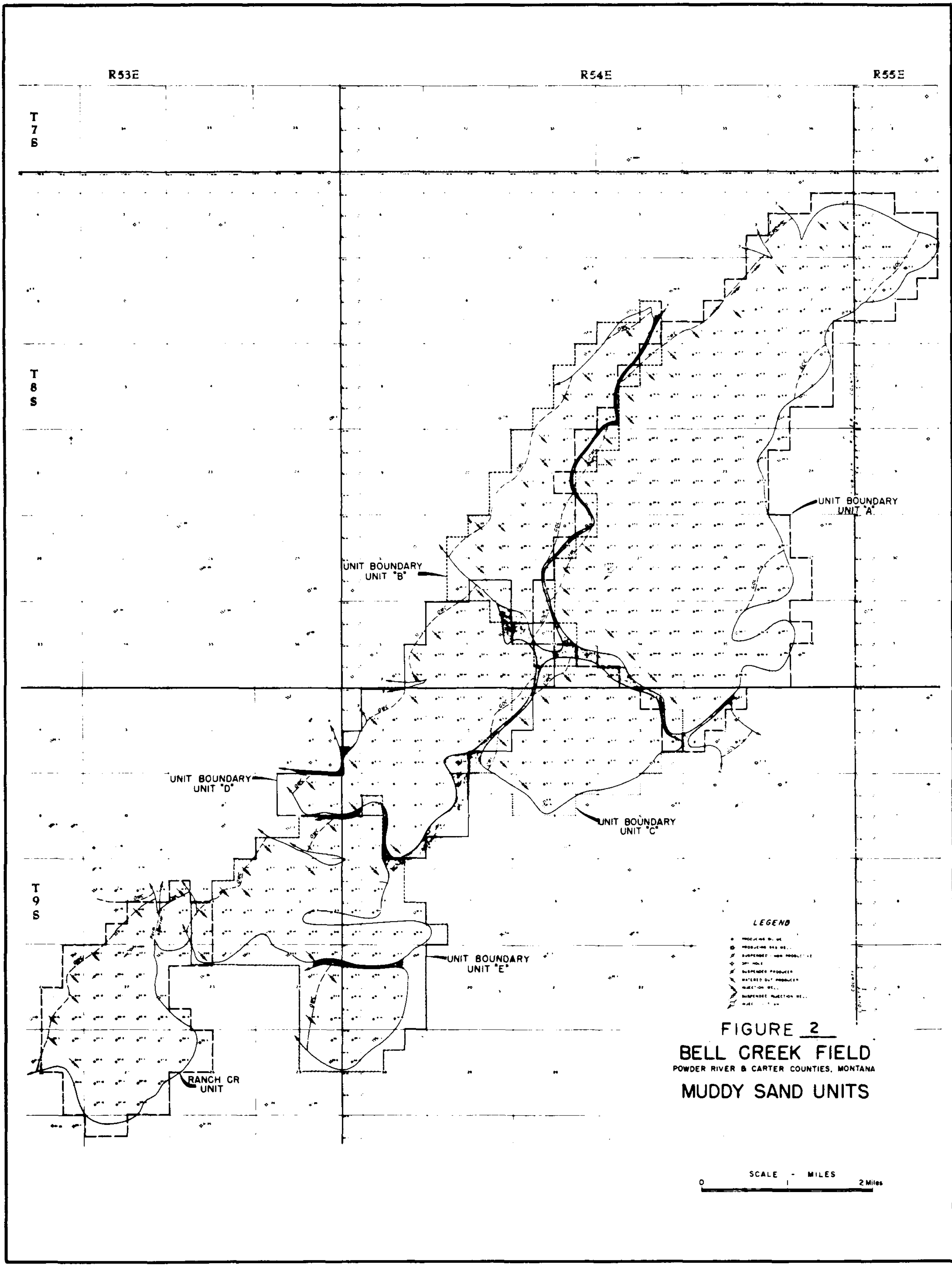
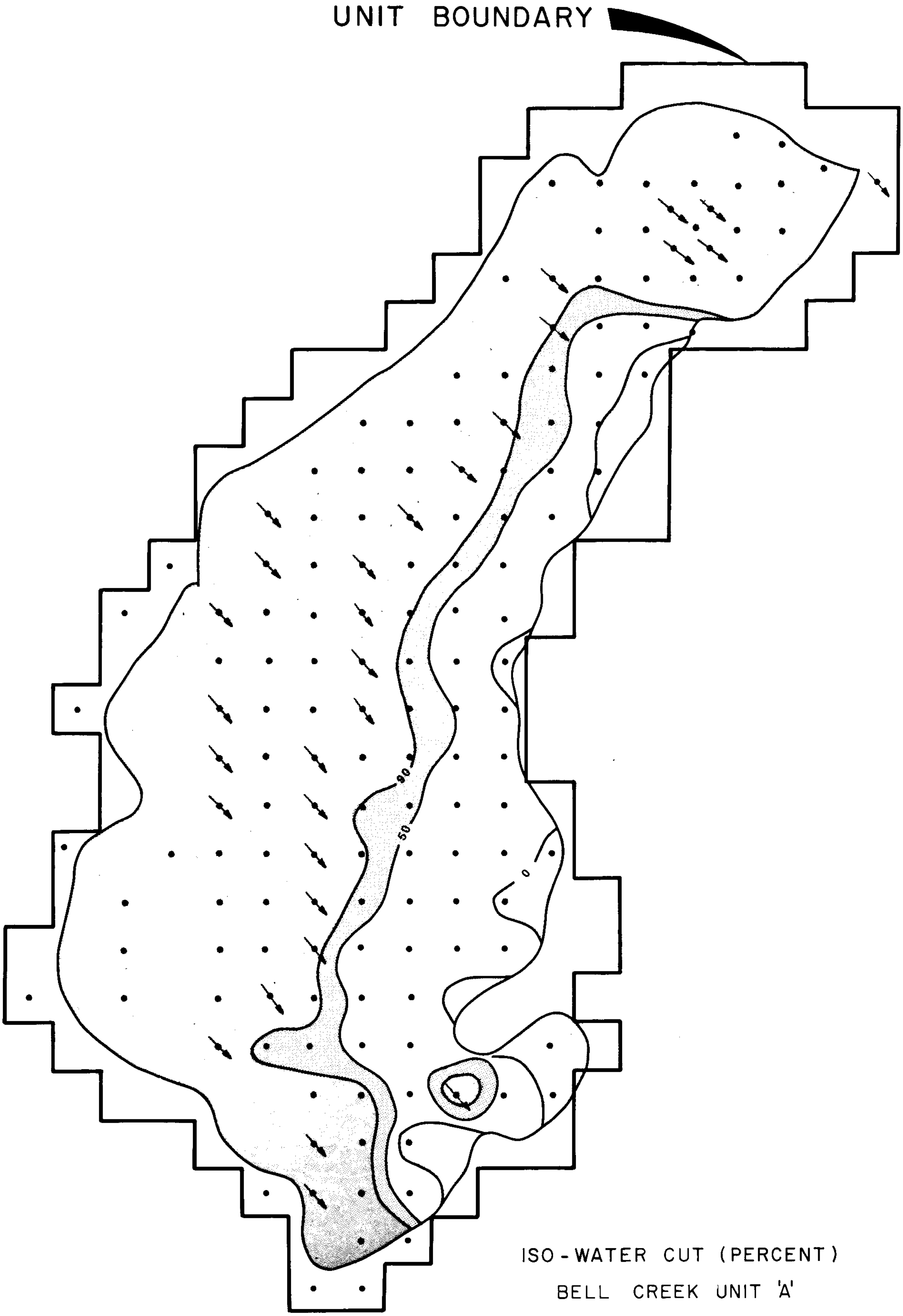

R53E
R54E
R55E
T 7 S
T 8 S
T 9 S
UNIT BOUNDARY
UNIT "A"
UNIT BOUNDARY
UNIT "B"
UNIT BOUNDARY
UNIT "C"
UNIT BOUNDARY
UNIT "D"
UNIT BOUNDARY
UNIT "E"
RANCH CR
UNIT
LEGEND
FIGURE 2
BELL CREEK FIELD
POWDER RIVER & CARTER COUNTIES, MONTANA
MUDDY SAND UNITS
SCALE - MILES
0
1
2 Miles

FIGURE 3



ISO-WATER CUT (PERCENT)
BELL CREEK UNIT 'A'
POWDER RIVER COUNTY, MONTANA

FIGURE 4

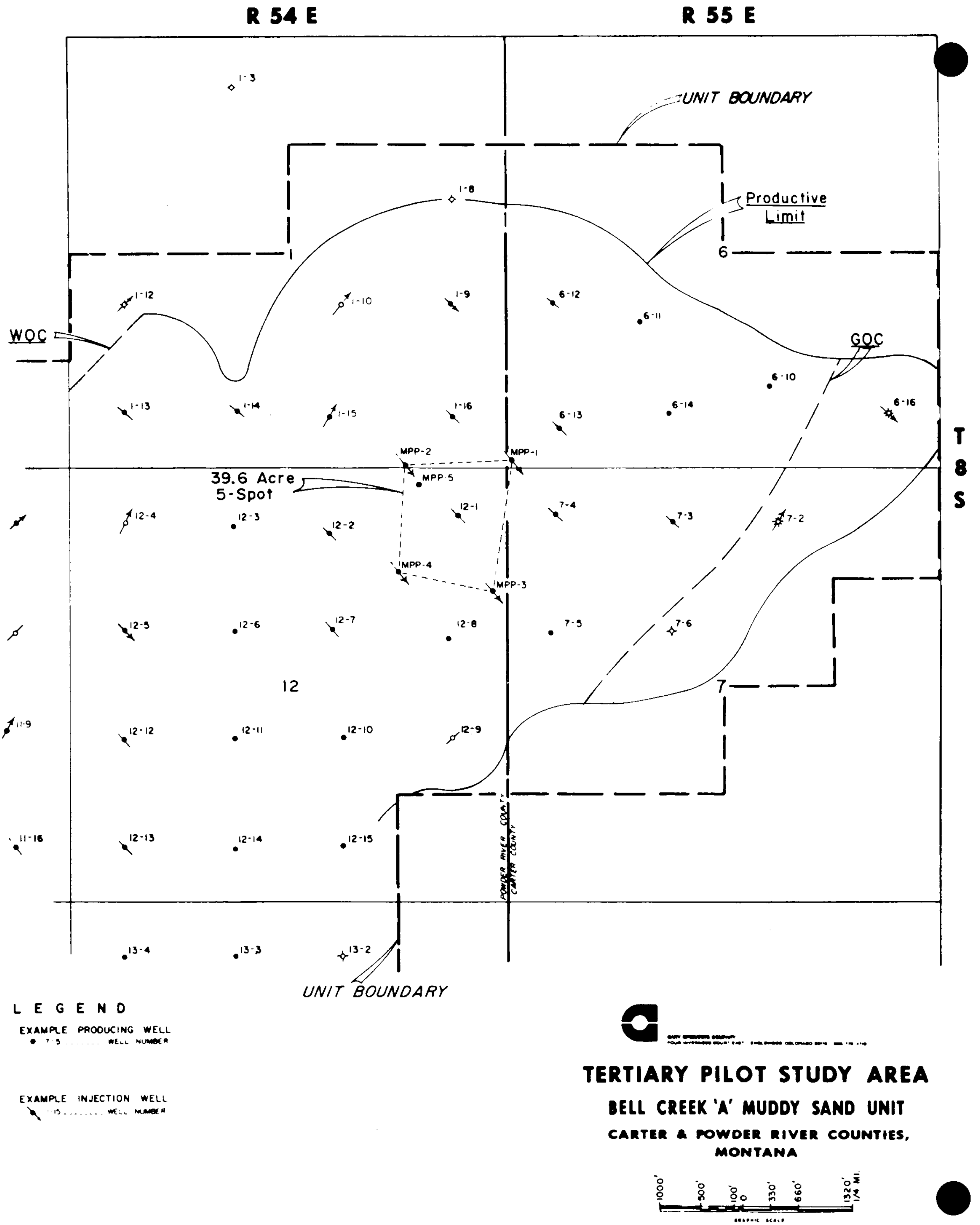

R 54 E
R 55 E
T 8 S
UNIT BOUNDARY
Productive Limit
WOC
GOC
39.6 Acre 5-Spot
UNIT BOUNDARY
POWDER RIVER COUNTY
CARTER COUNTY
LEGEND
EXAMPLE PRODUCING WELL
EXAMPLE INJECTION WELL
TERTIARY PILOT STUDY AREA
BELL CREEK 'A' MUDDY SAND UNIT
CARTER & POWDER RIVER COUNTIES, MONTANA

FIGURE 5

OIL-WATER RELATIVE PERMEABILITY CURVES
SAMPLE NUMBER 3 (MPP-1)

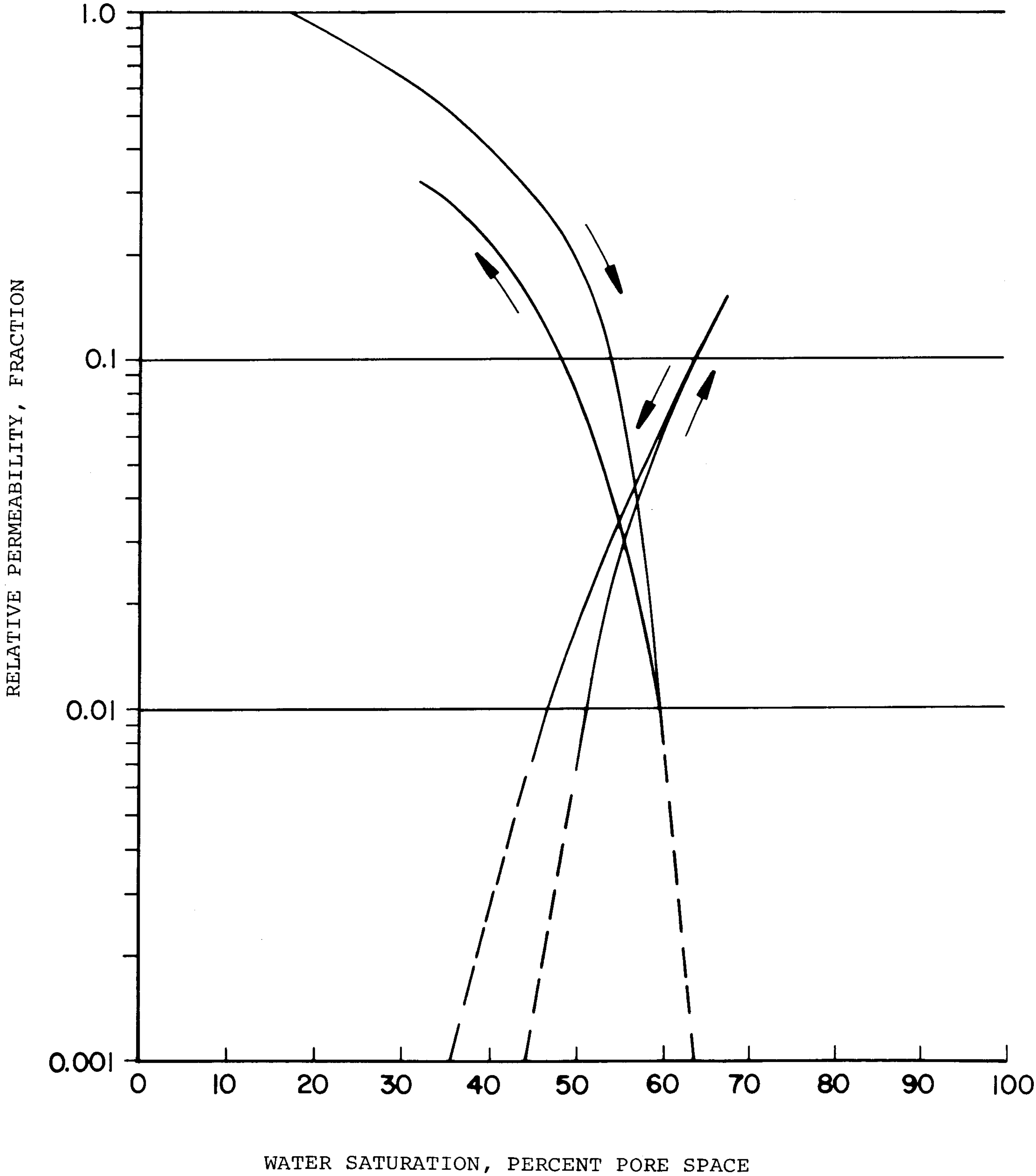


FIGURE 6

OIL-WATER RELATIVE PERMEABILITY CURVES
SAMPLE NUMBER 16 (MPP-5)

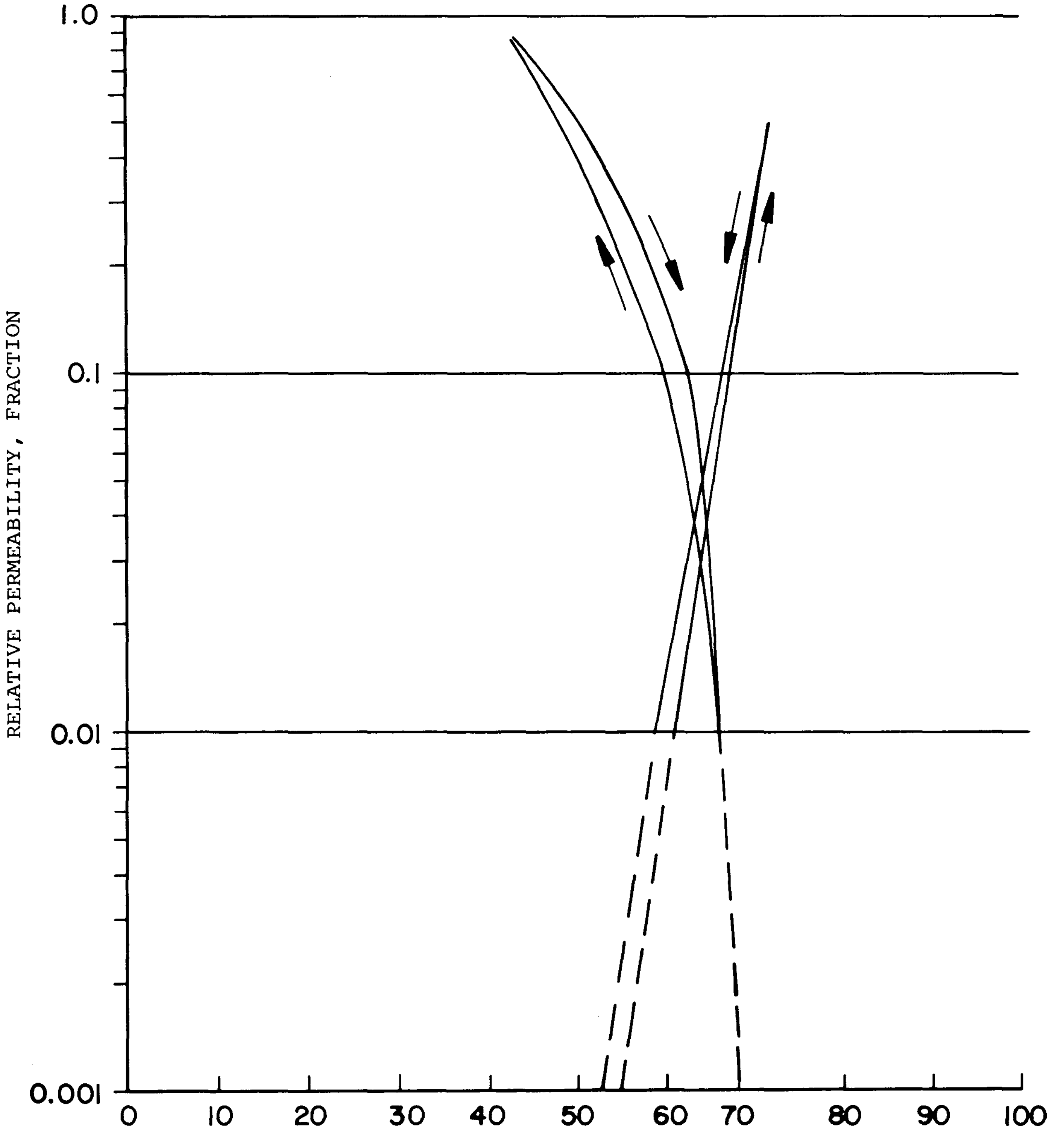


FIGURE 7

PRESSURE TRANSIENT TEST PATTERN
DECEMBER, 1976

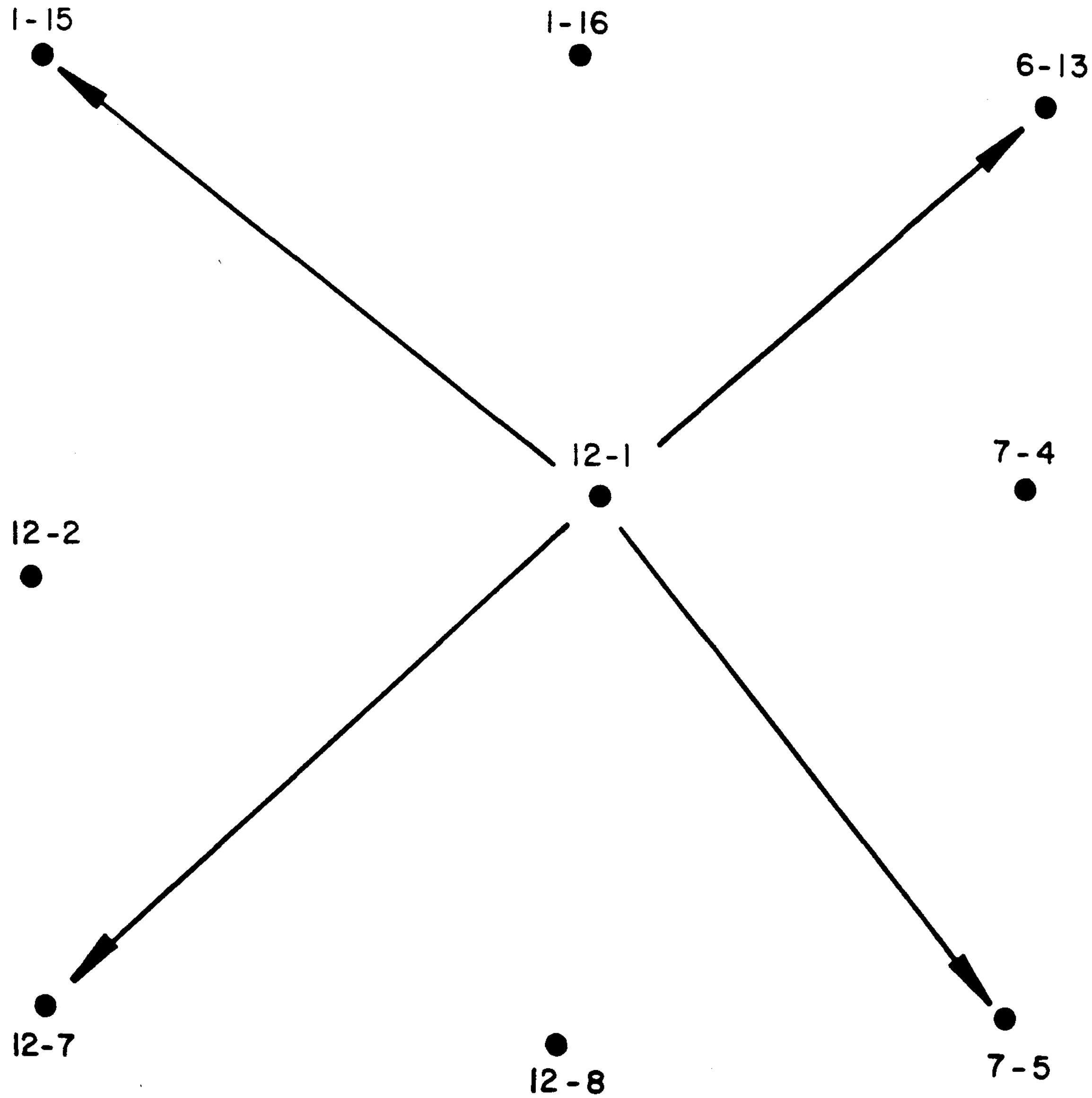
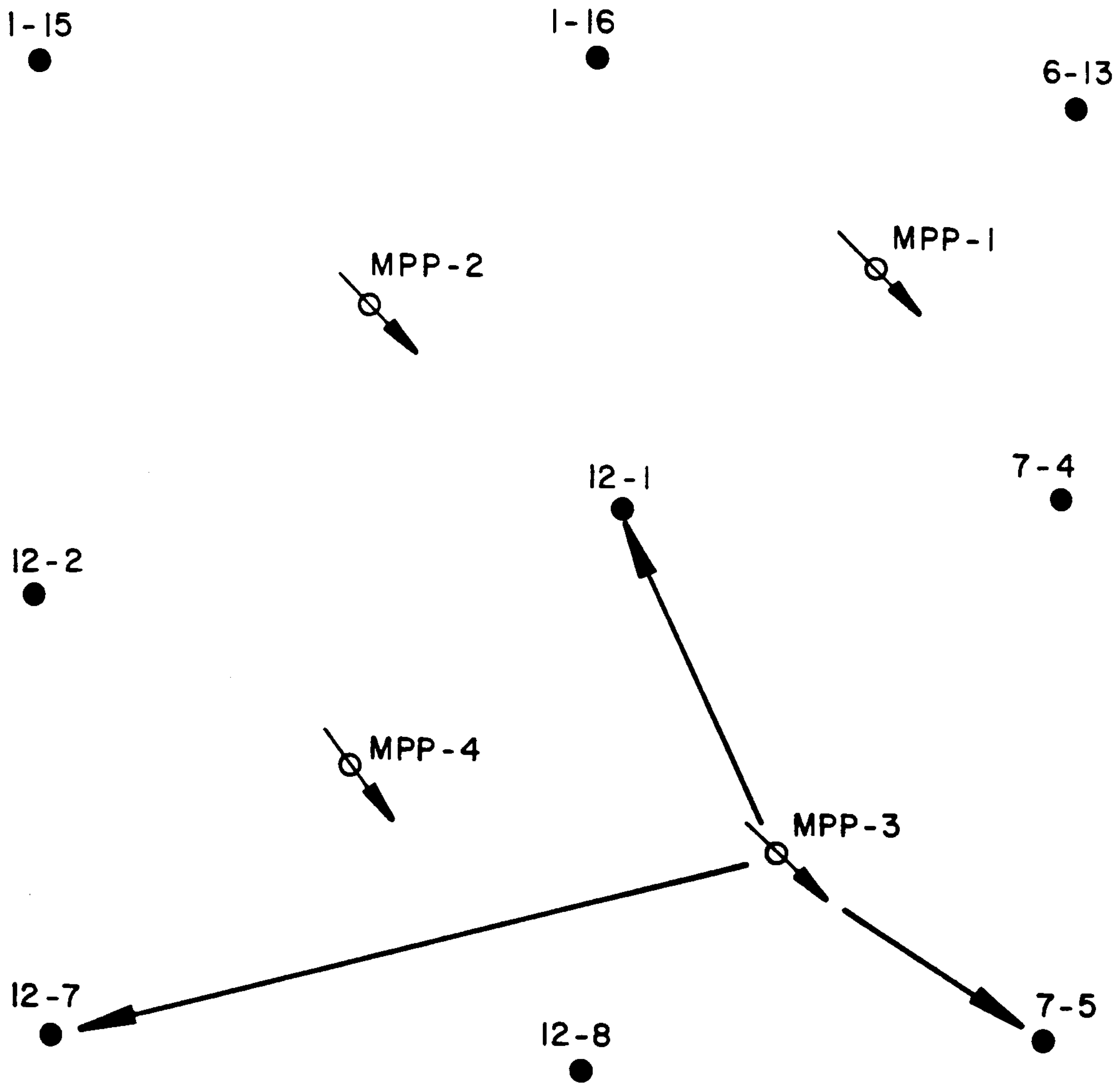


FIGURE 8

PRESSURE TRANSIENT TEST PATTERN
MAY, 1978



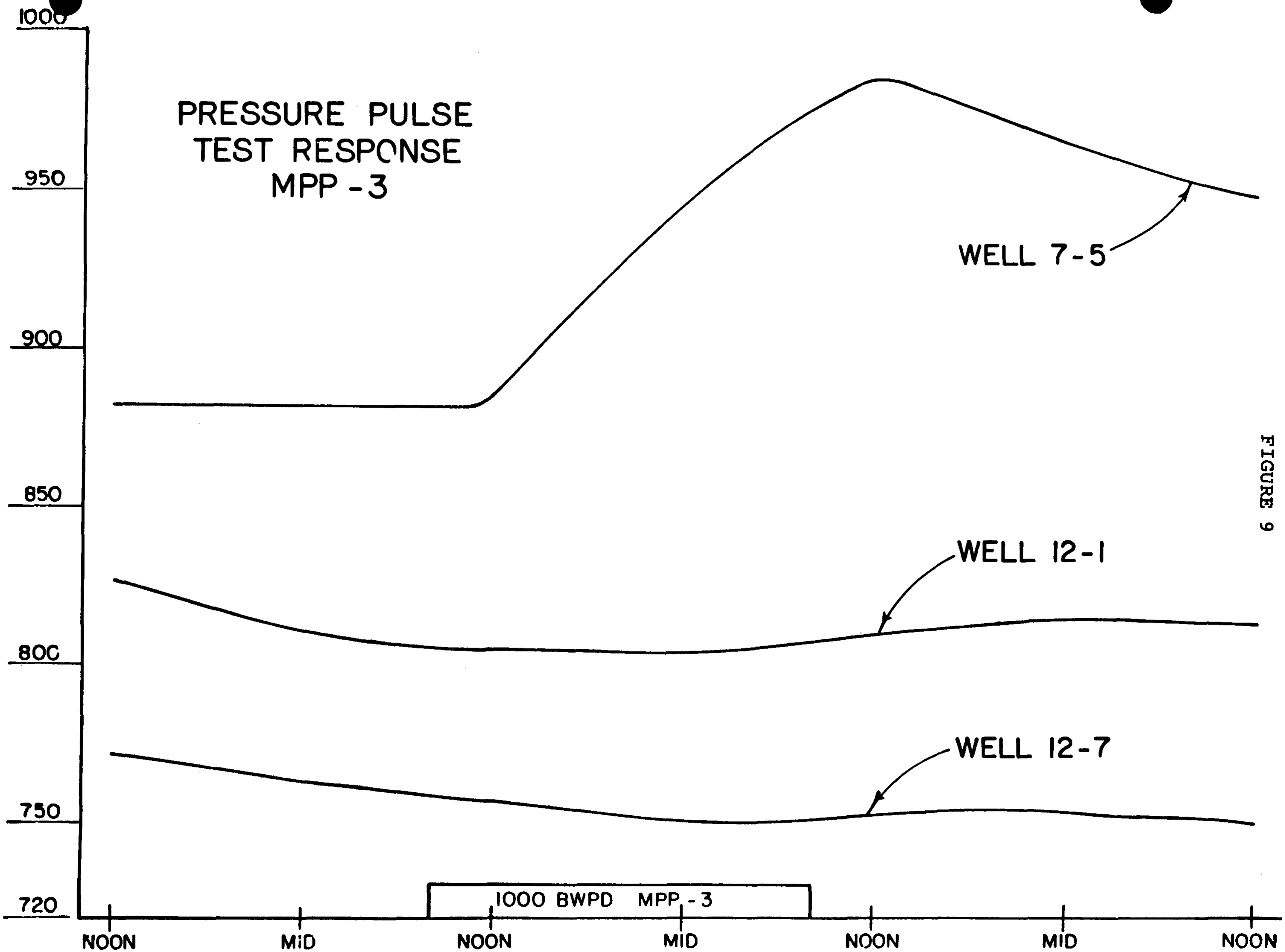
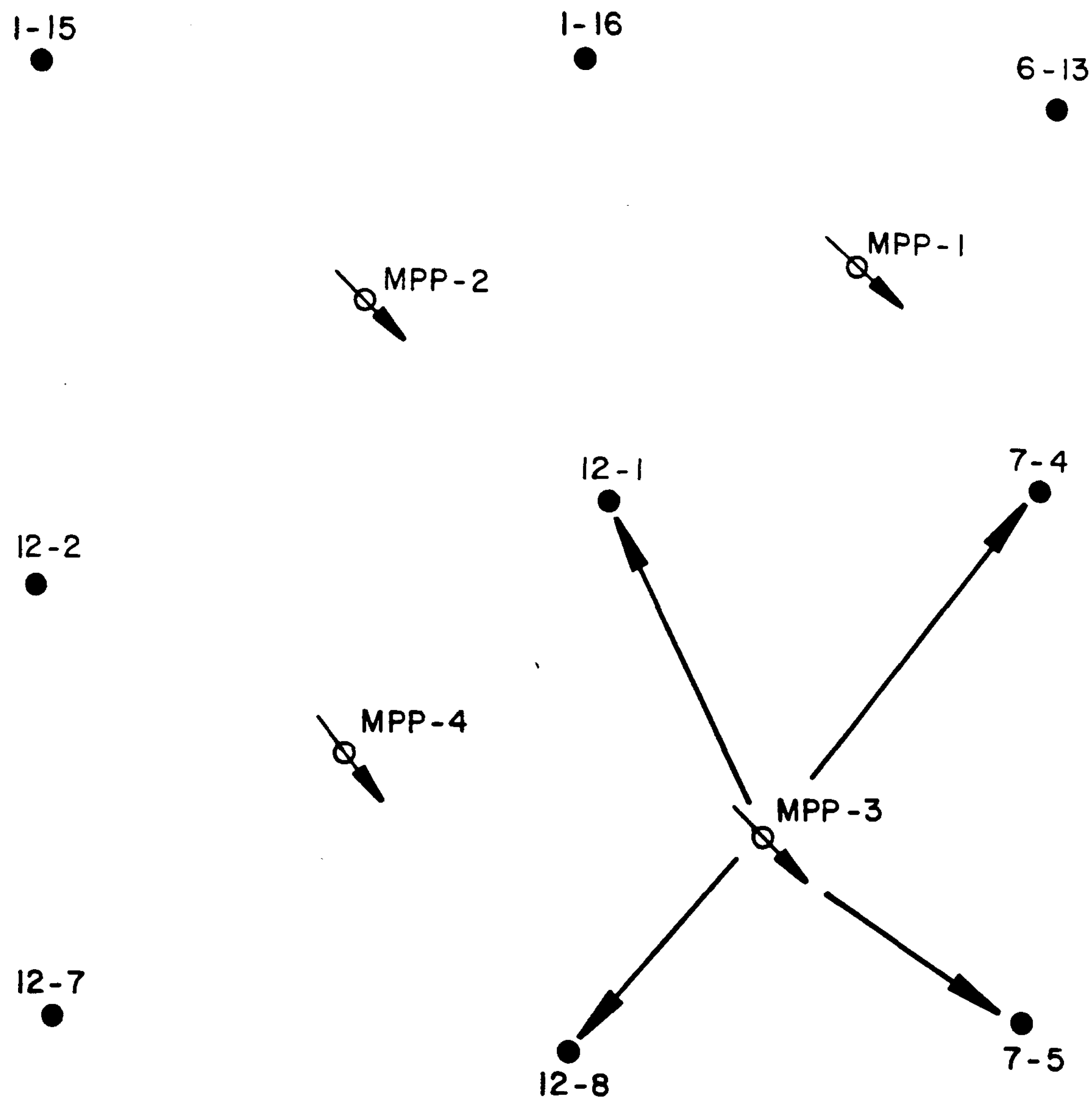

PRESSURE PULSE
TEST RESPONSE
MPP -3
1000
950
900
850
800
750
720
WELL 7-5
WELL 12-1
WELL 12-7
1000 BWPD MPP - 3
NOON
MID
NOON
MID
NOON
MID
NOON

FIGURE 9

FIGURE 10

PRESSURE TRANSIENT TEST PATTERN
JUNE, 1978



MPP-3 PRESSURE PULSE TEST

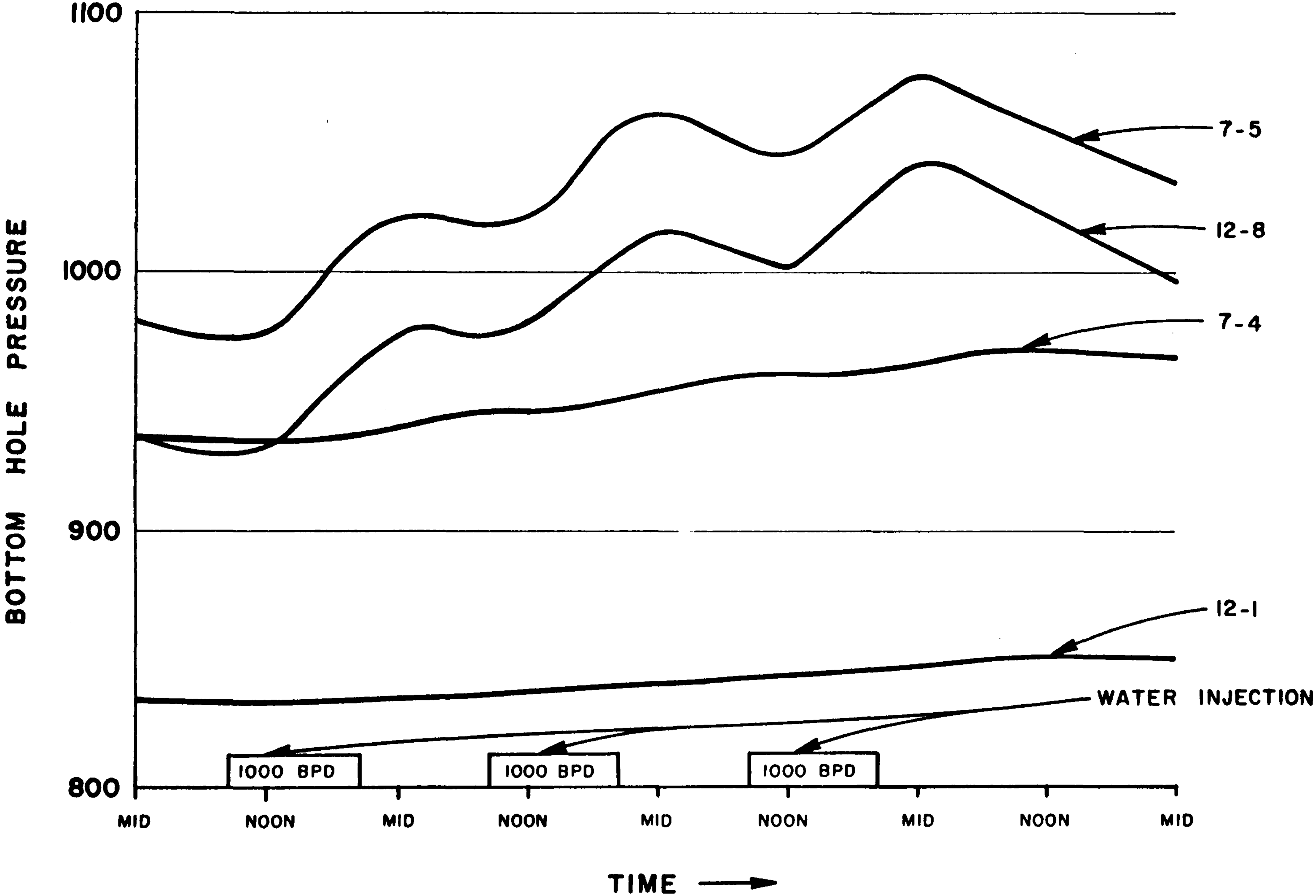
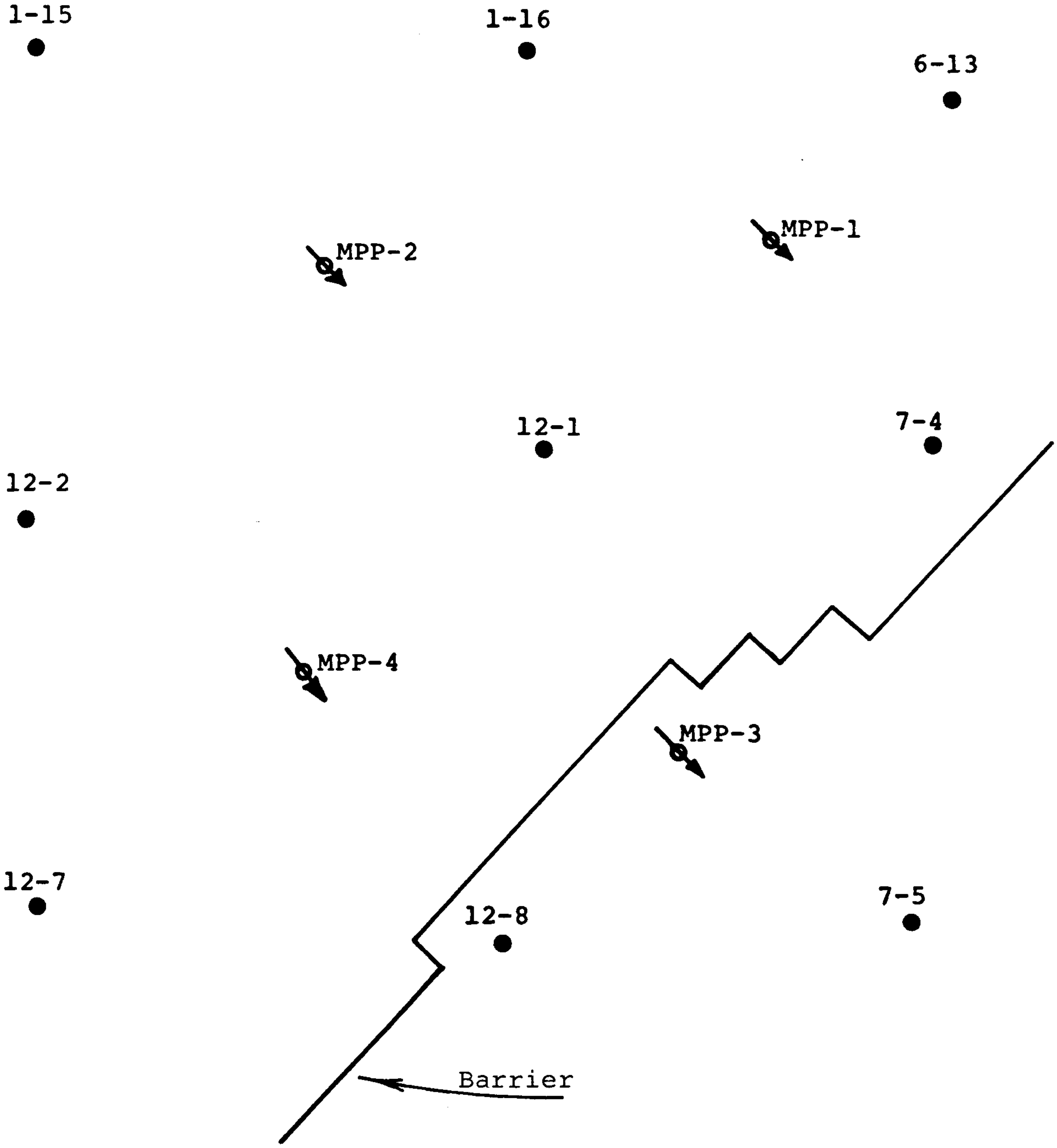


FIGURE 11

Figure 12

MATHEMATICAL MODEL BARRIER CONFIGURATION



MODEL GRID SYSTEM FOR PREFLUSH SIMULATION

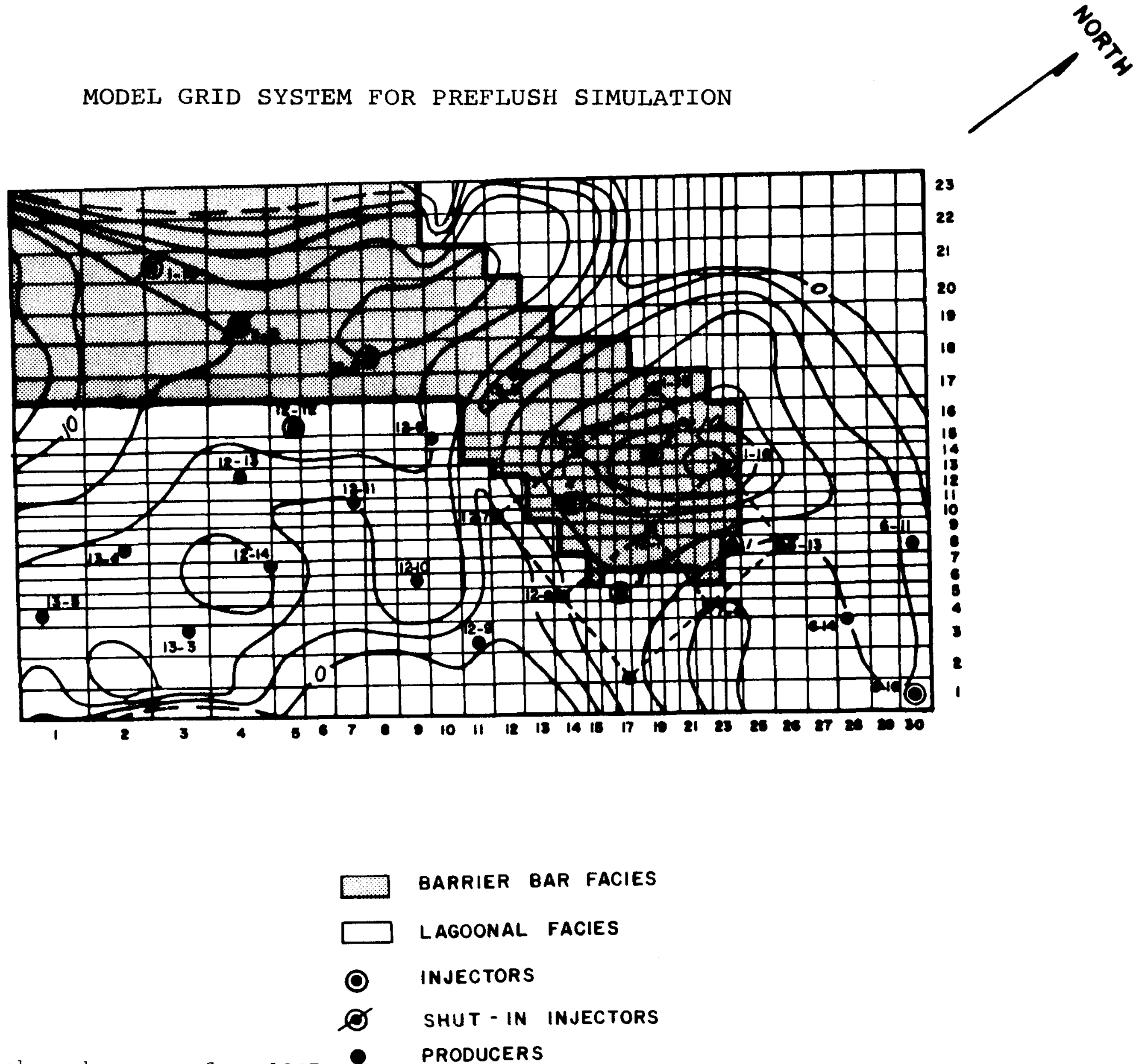
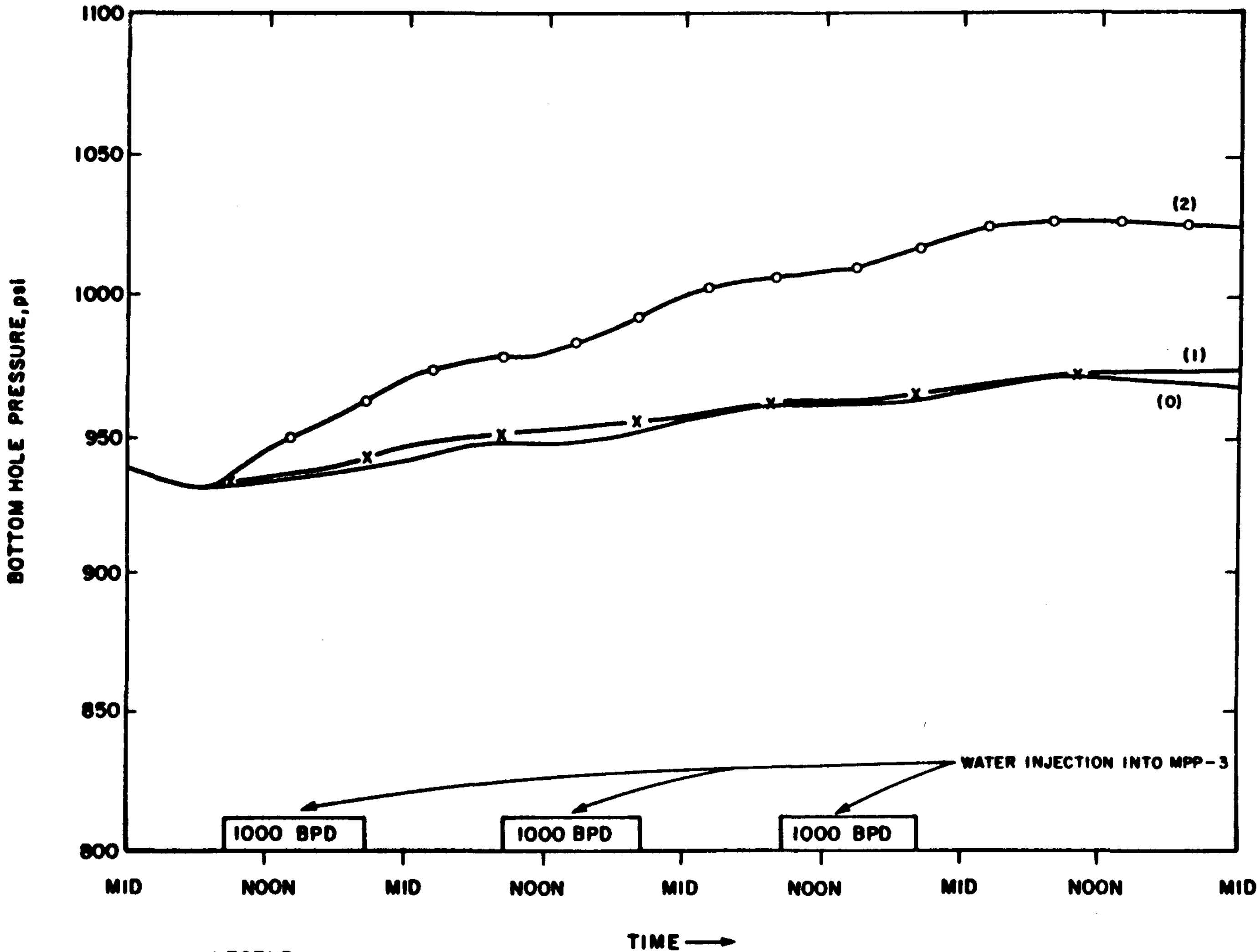


FIGURE 13

NOTE: Isopach contours shown here are from 1967 Bell Creek Engineering Committee's study... these were not used in the simulation work documented in this report. Union Oil Company's net pay distribution as described in Fig. 3 of their memorandum dated March 9, 1978 and entitled "Final Estimate of Pore Volume and Permeability Variation in the Bell Creek Pilot Area", was used for the simulation work.

MPP-3 PRESSURE PULSE TEST
RESPONSE IN WELL 7-4
(SINGLE-LAYER RESERVOIR PROTOTYPE)



LEGEND

(0) OBSERVED RESPONSE

(1) SIMULATED WITH BARRIER

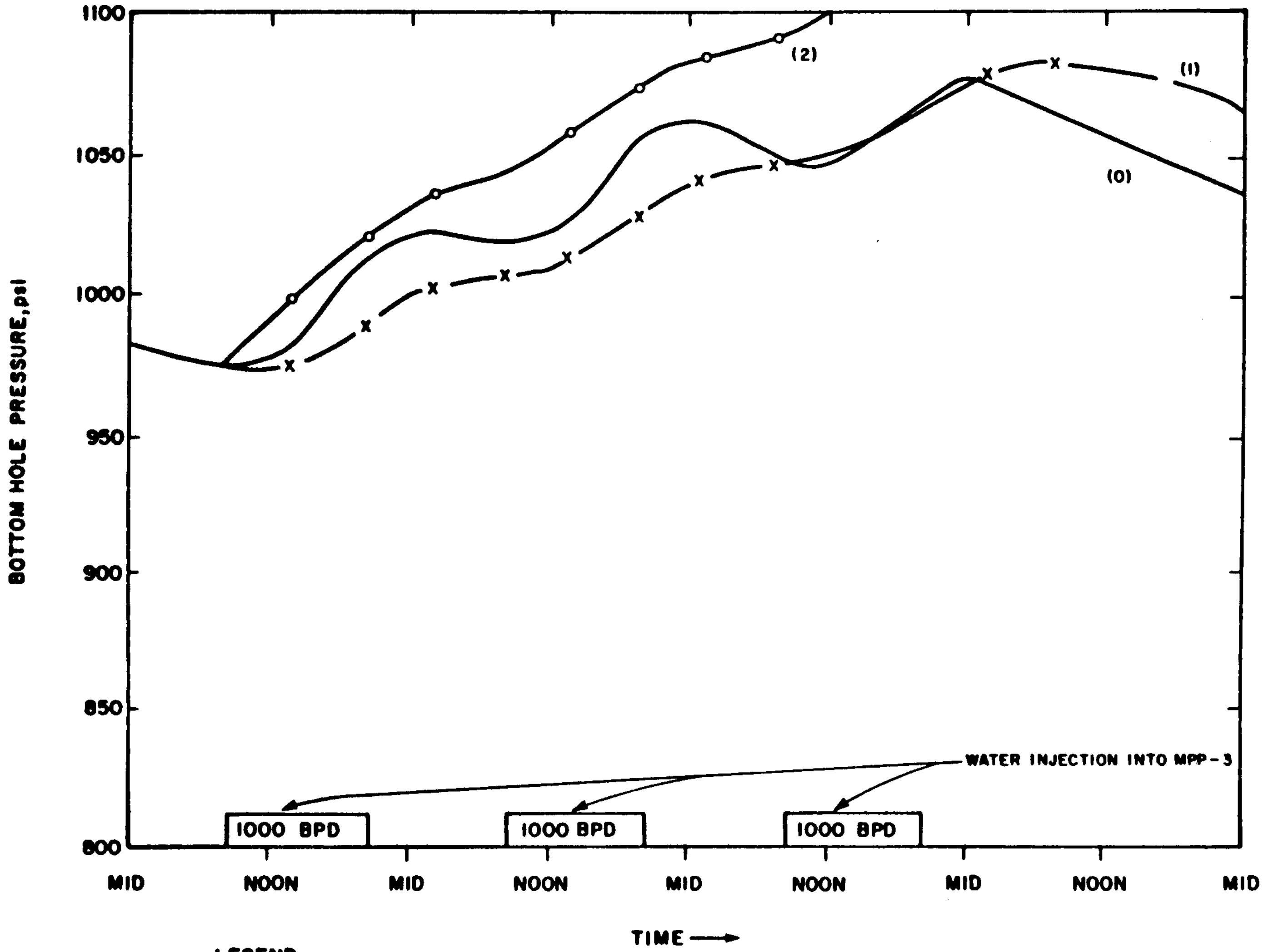
(2) SIMULATED WITH NO BARRIER & INCREASED PORE VOLUME

FIGURE 14

MPP-3 PRESSURE PULSE TEST

RESPONSE IN WELL 7-5

(SINGLE-LAYER RESERVOIR PROTOTYPE)



LEGEND

(O) OBSERVED RESPONSE

(1) SIMULATED WITH BARRIER

(2) SIMULATED WITH NO BARRIER & INCREASED PORE VOLUME

FIGURE 15

MPP-3 PRESSURE PULSE TEST

RESPONSE IN WELL 12-1

(SINGLE-LAYER RESERVOIR PROTOTYPE)

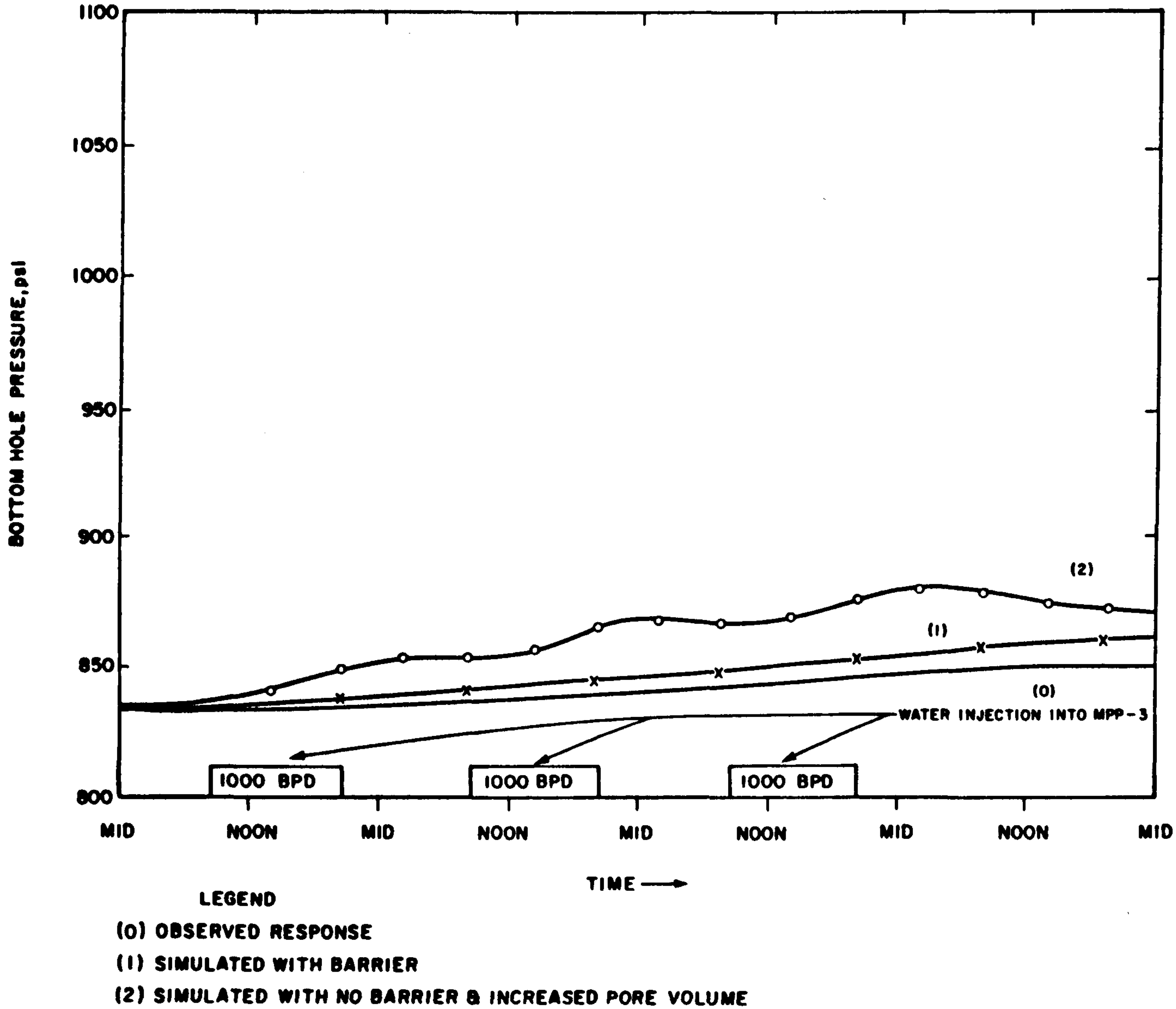
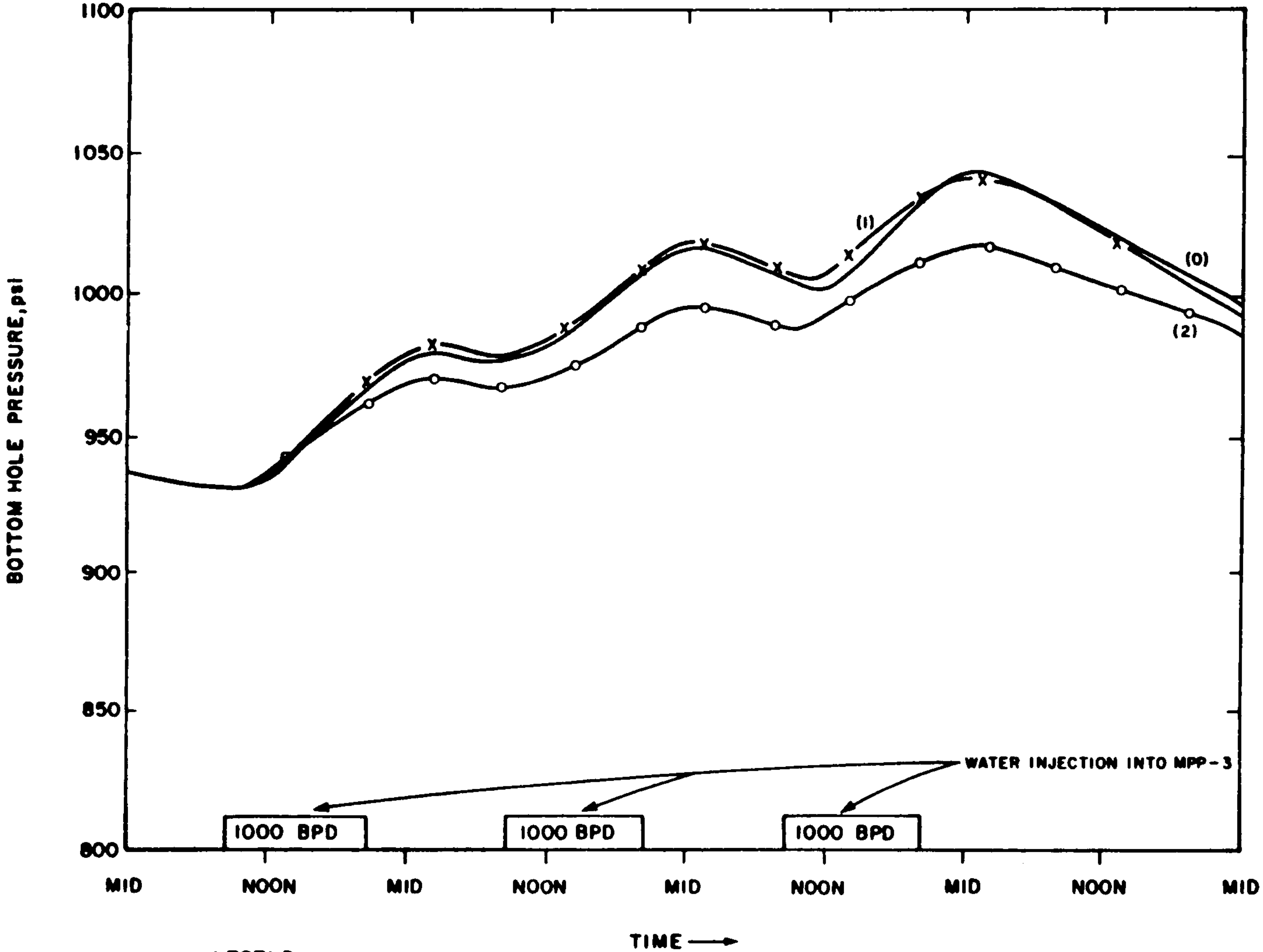


FIGURE 16

MPP-3 PRESSURE PULSE TEST

RESPONSE IN WELL 12-8

(SINGLE-LAYER RESERVOIR PROTOTYPE)



LEGEND

(0) OBSERVED RESPONSE

(1) SIMULATED WITH BARRIER

(2) SIMULATED WITH NO BARRIER & INCREASED PORE VOLUME

FIGURE 17

FIGURE 18

TRACER BREAKTHROUGH TIMES

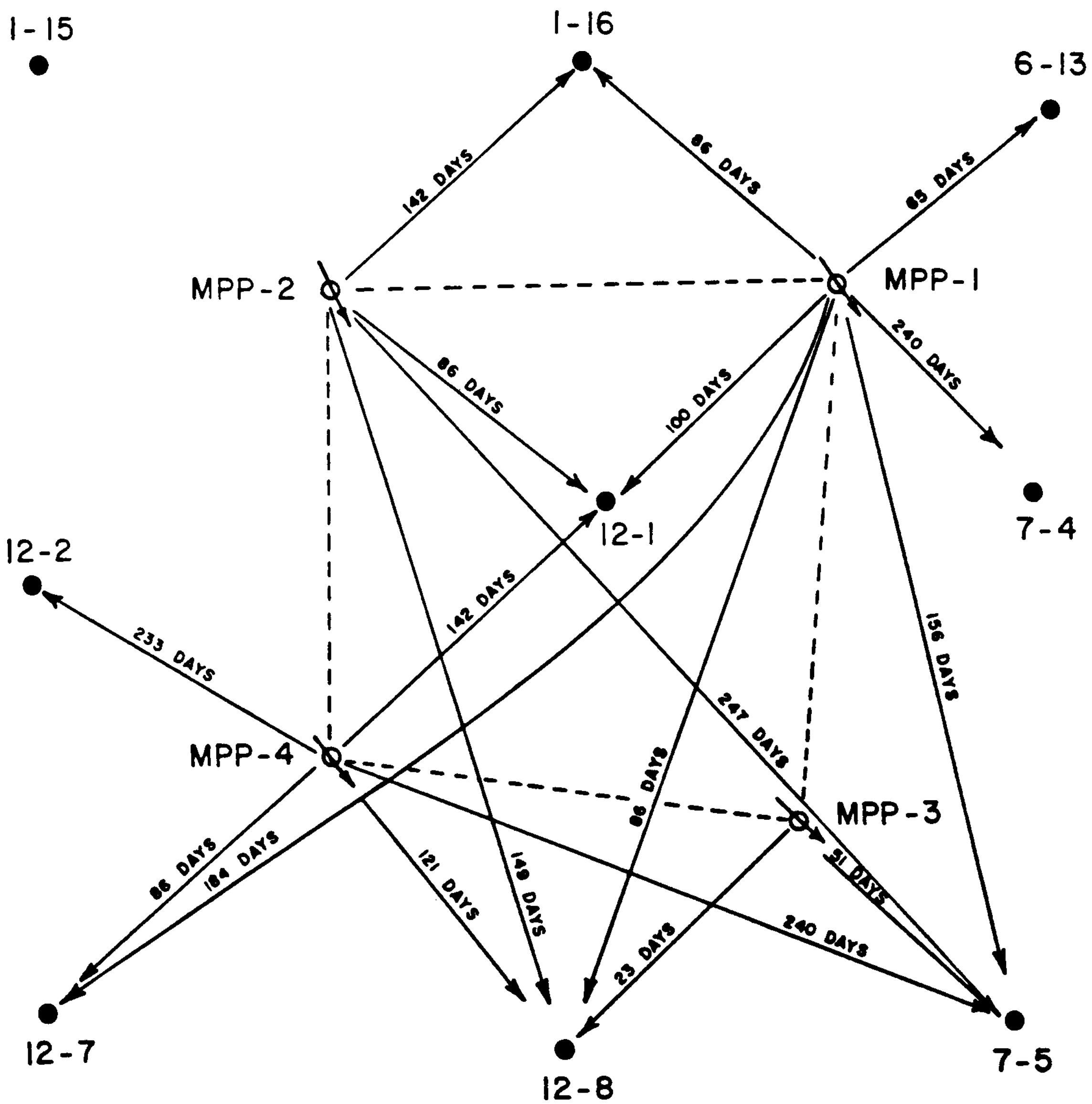
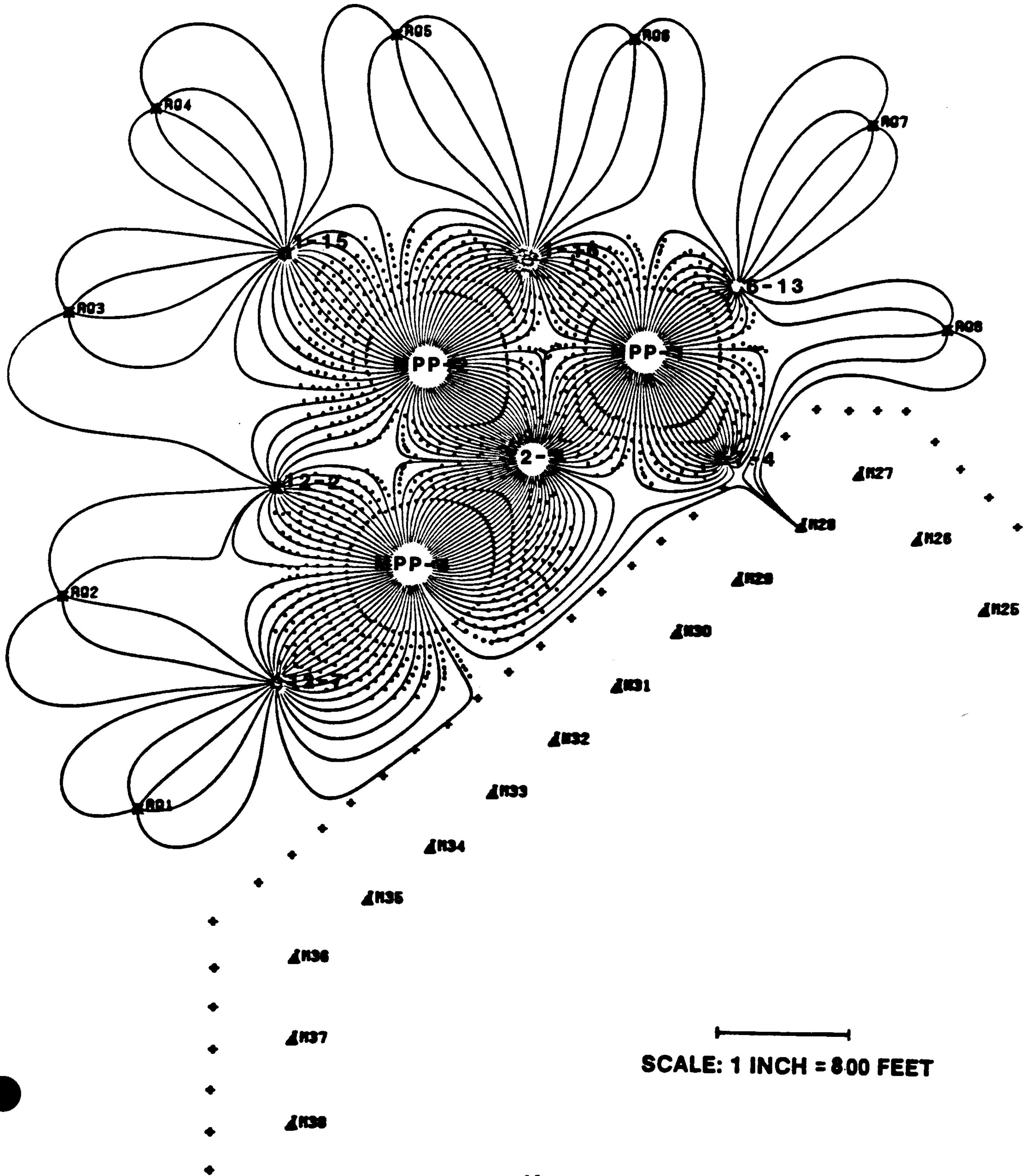


FIGURE 19

CASE 3 STREAMCHANNEL MAP



UNION'S TOTAL NET PAY

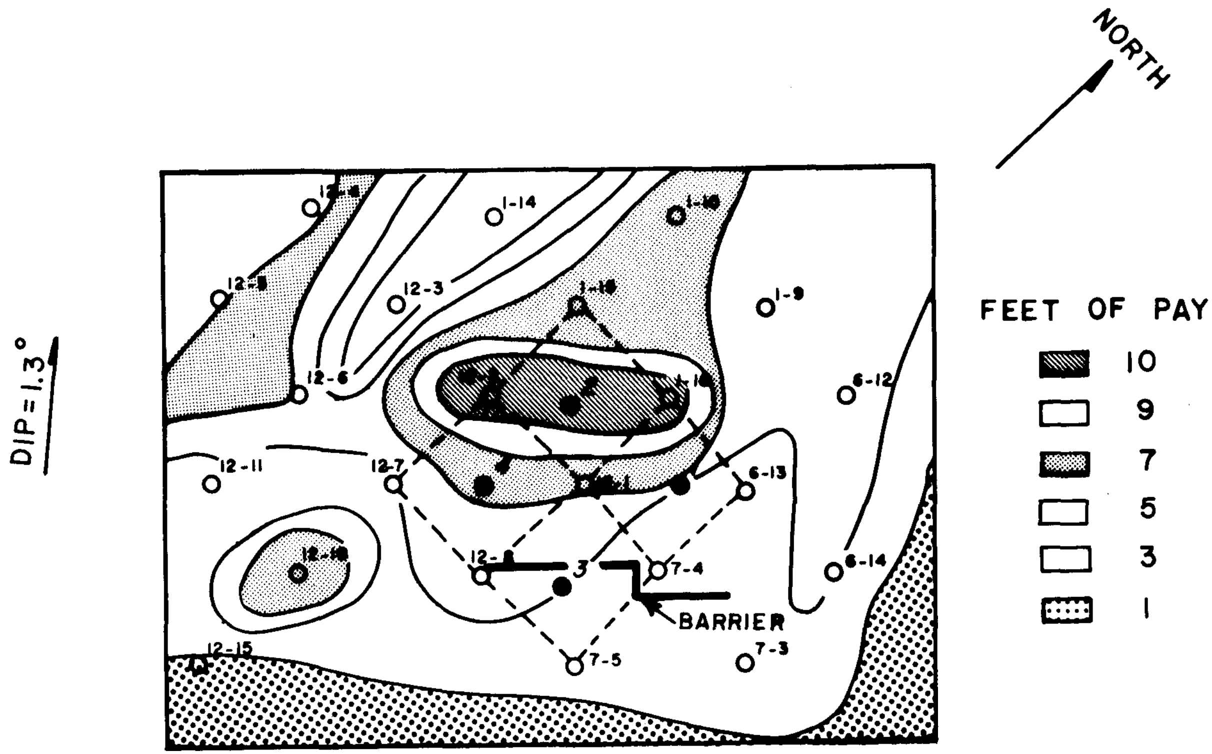


FIGURE 20

LAYER 1

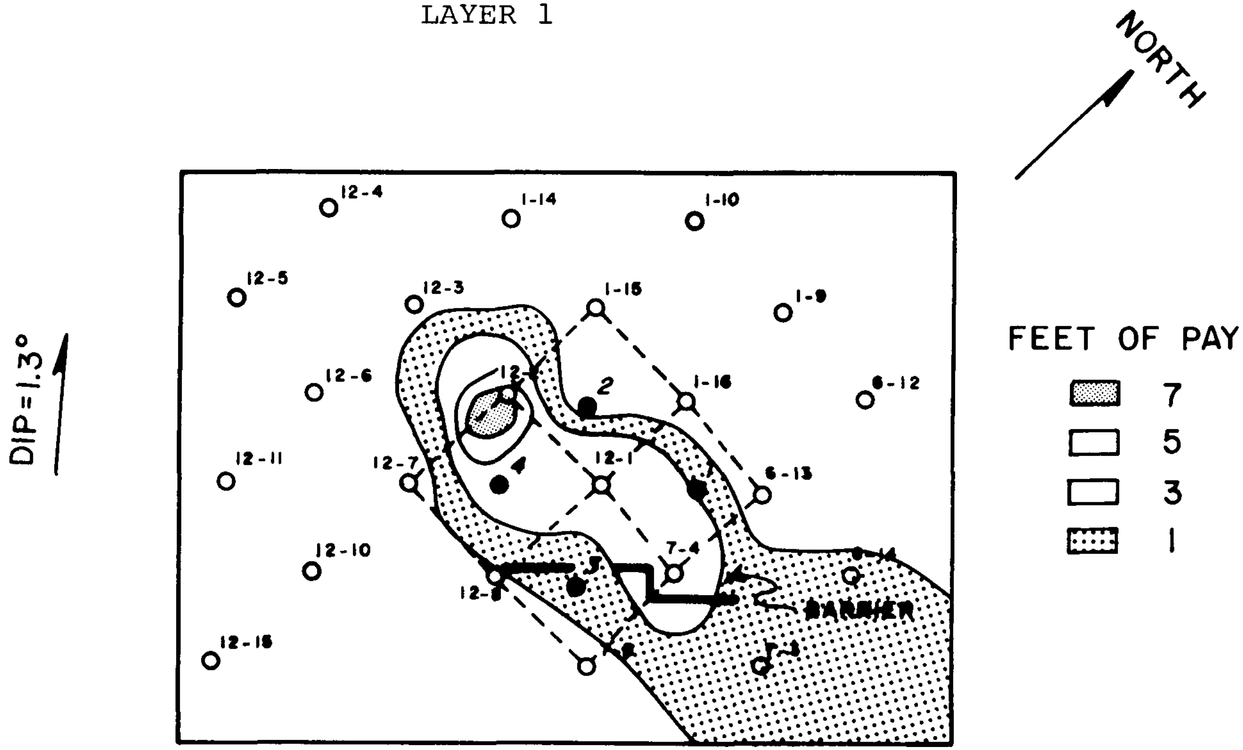
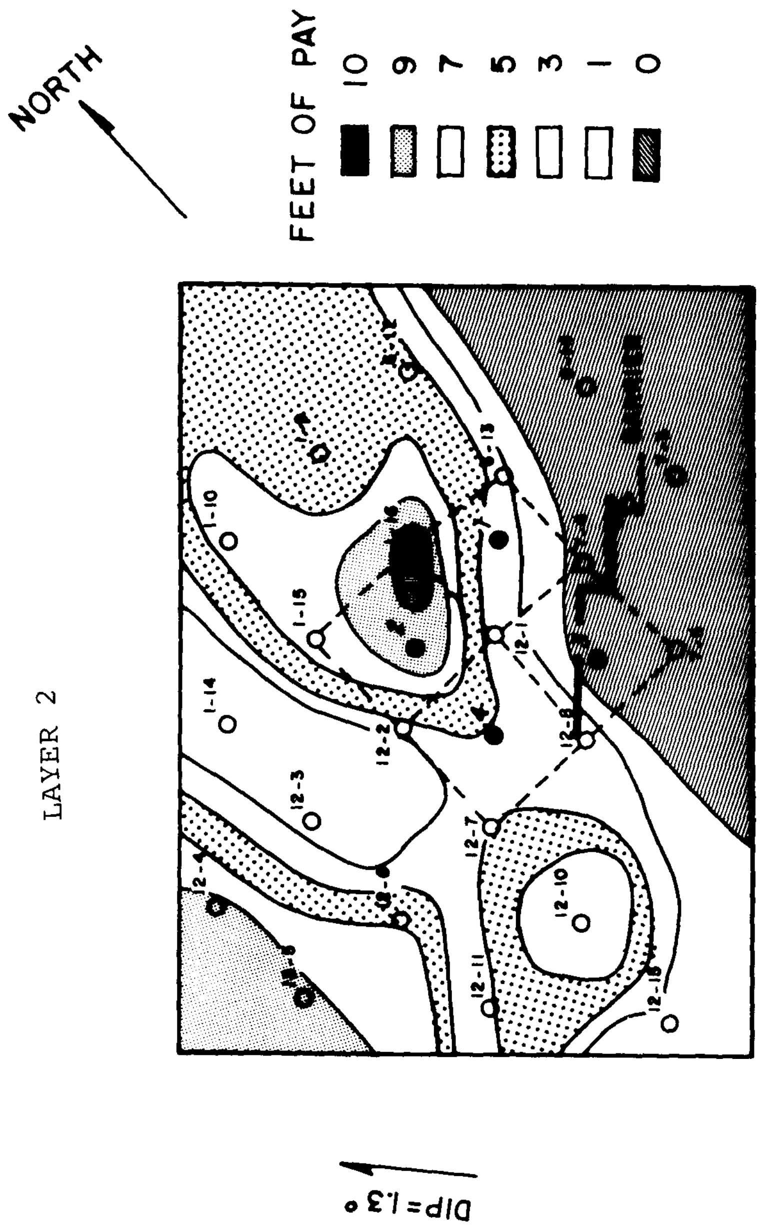


FIGURE 21

FIGURE 22



LAYER 2

LAYER 3

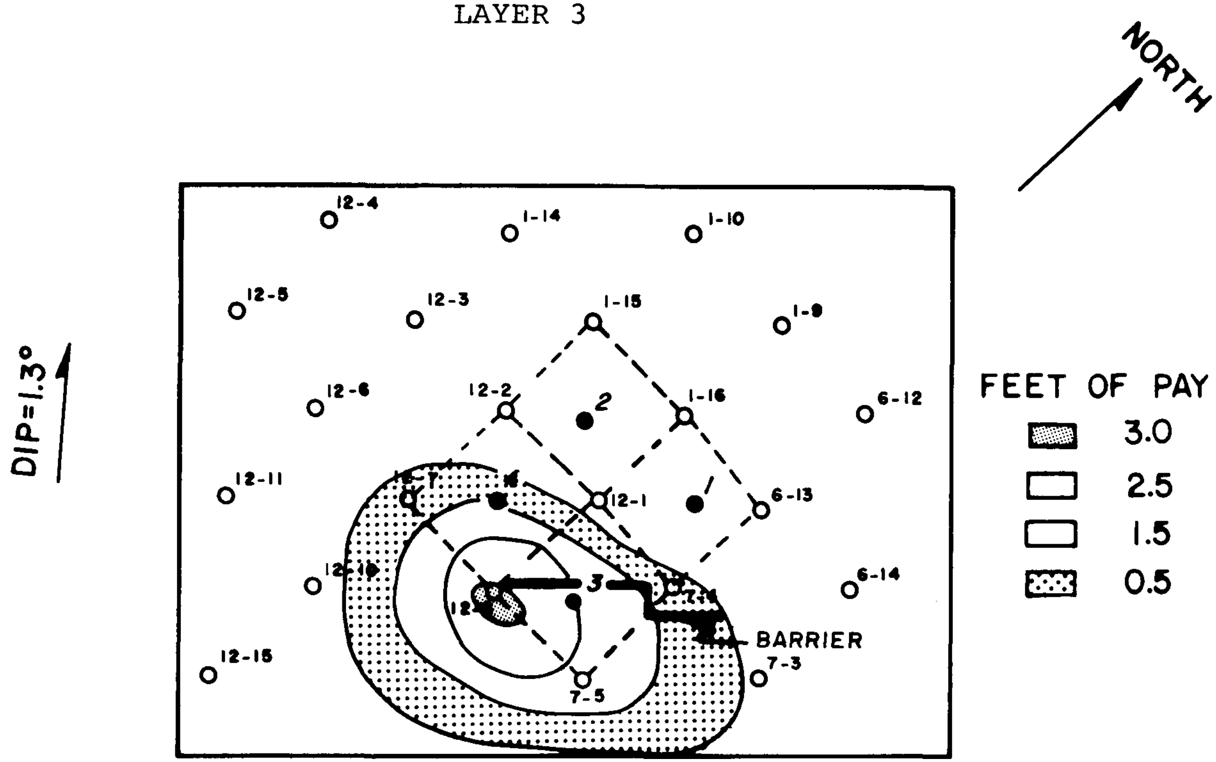
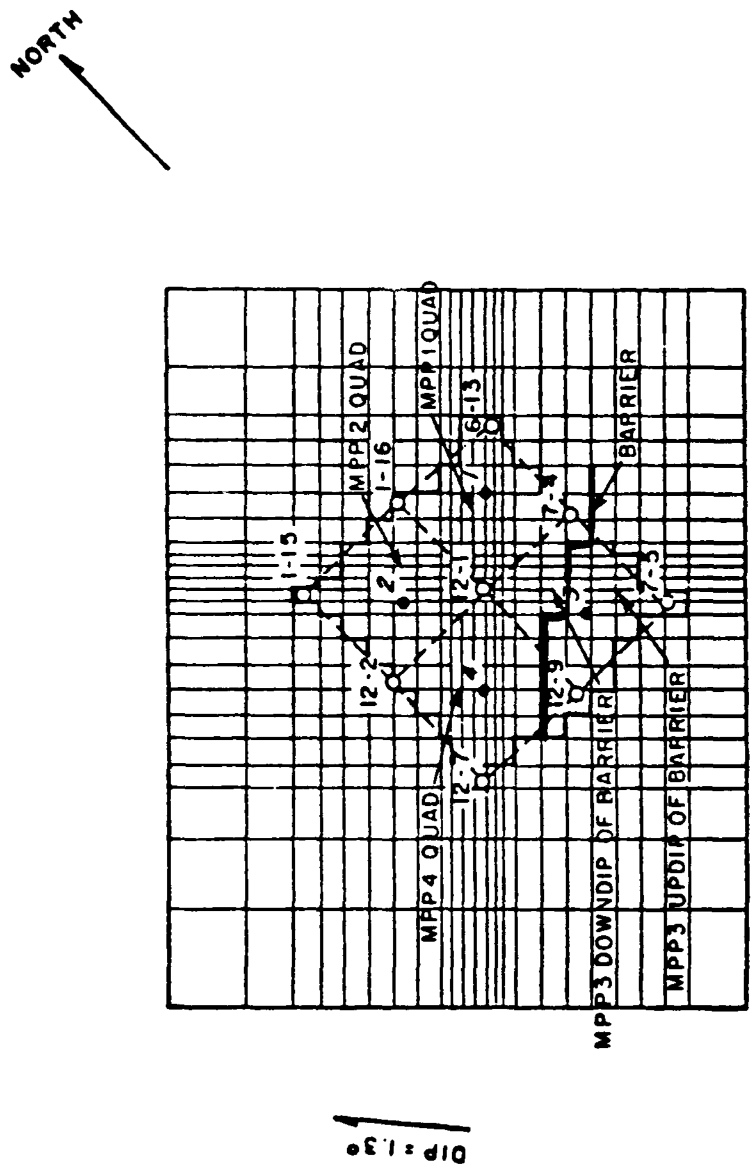


FIGURE 23

FIGURE 24

DEFINITION OF QUADRANTS AND FRACTIONAL QUADRANTS

160-ACRE PILOT AREA



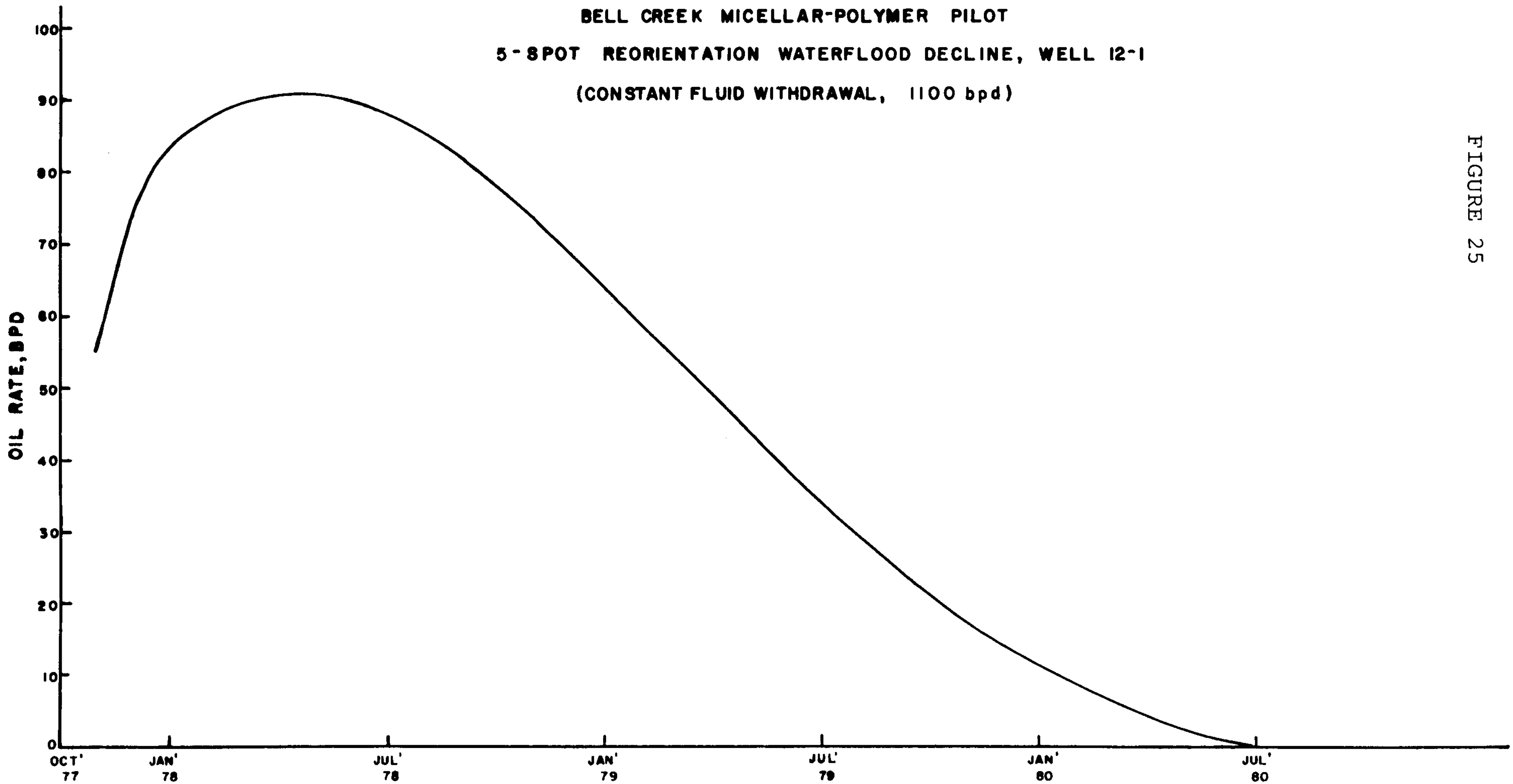

BELL CREEK MICELLAR-POLYMER PILOT
5-SPOT REORIENTATION WATERFLOOD DECLINE, WELL 12-1
(CONSTANT FLUID WITHDRAWAL, 1100 bpd)
OIL RATE, BPD
100
90
80
70
60
50
40
30
20
10
0
OCT' 77
JAN' 78
JUL' 78
JAN' 79
JUL' 79
JAN' 80
JUL' 80

FIGURE 25

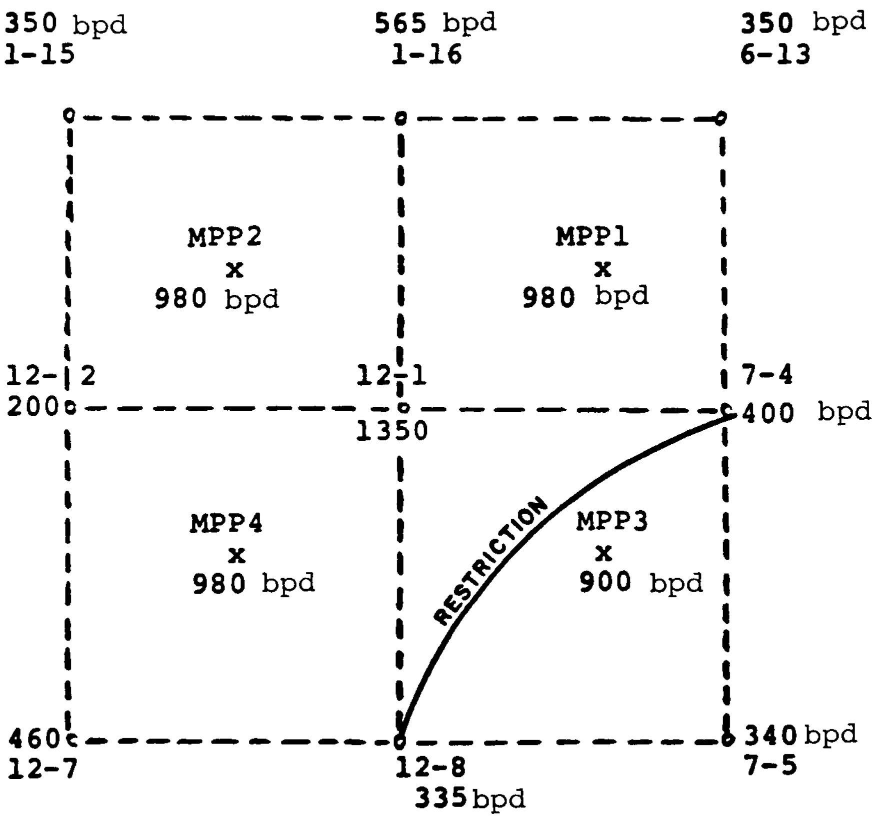
FIGURE 26

Preflush Pattern Balance Simulation

CASE 1

CURRENT UNBALANCED WELL RATES

ALL SURROUNDING CURRENTLY ACTIVE WELLS ARE INJECTING & PRODUCING



TRACER OR PREFLUSH BREAKTHROUGH TIMES

Pilot Wells	Field Tracer (Days)	Simulated Preflush (Days)
1-15	<100	90-130
1-16	90	90-130
6-13	< 50	15-30
12-2	None	None
12-1	50-100	60-90
7-4	0-50	60-90
12-7	60-90	15-30
12-8	15-30	15-30
7-5	<50	15-30

TOTAL 160-ACRE PILOT RATES

Injection: 3840 bpd
Production: 4350 bpd

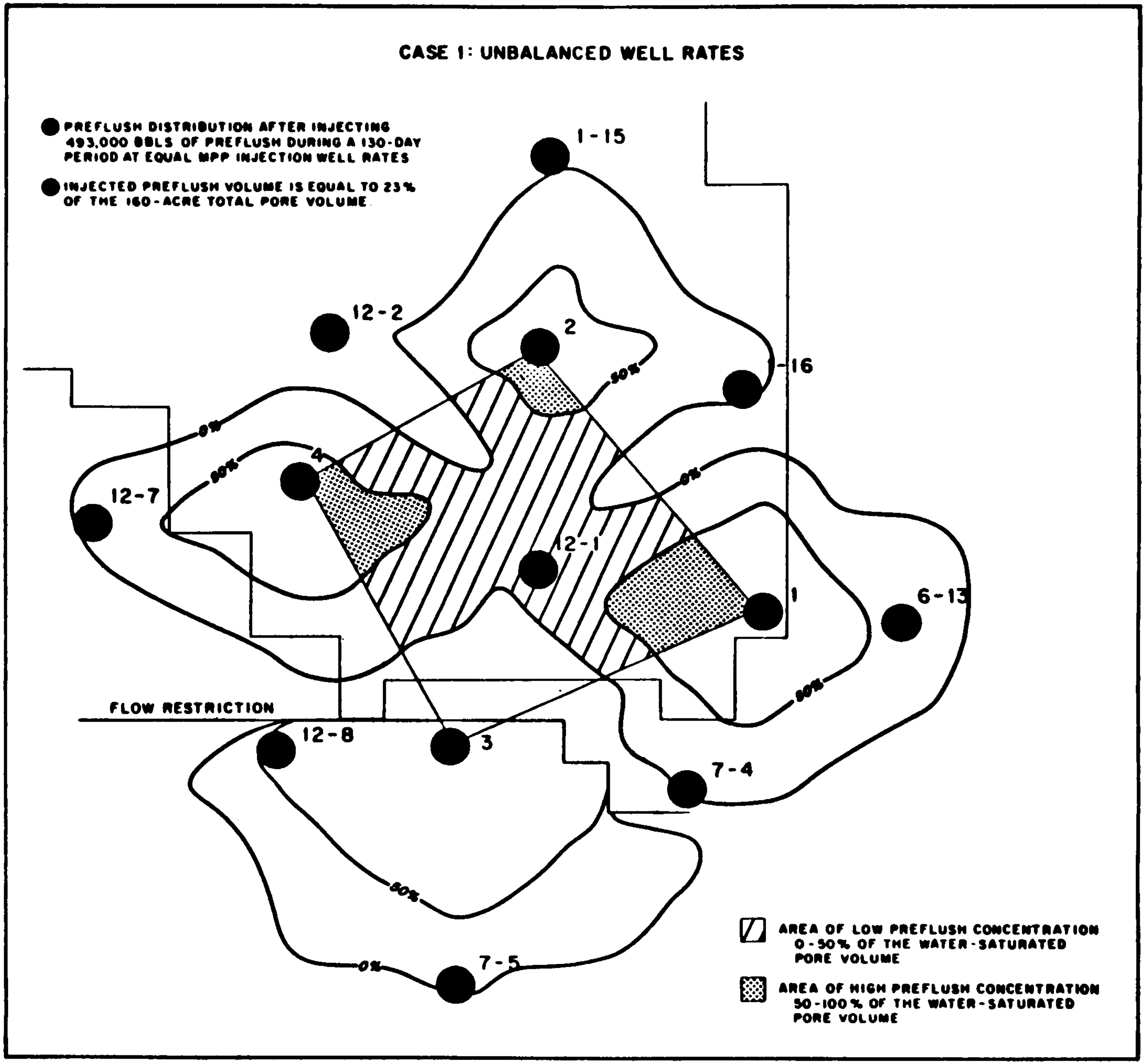

CASE 1: UNBALANCED WELL RATES
PREFLUSH DISTRIBUTION AFTER INJECTING 493,000 BBLS OF PREFLUSH DURING A 130-DAY PERIOD AT EQUAL MPP INJECTION WELL RATES
INJECTED PREFLUSH VOLUME IS EQUAL TO 23% OF THE 160-ACRE TOTAL PORE VOLUME
1-15
12-2
2
1-16
4
12-7
12-1
1
6-13
FLOW RESTRICTION
12-8
3
7-4
7-5
0%
50%
AREA OF LOW PREFLUSH CONCENTRATION 0-50% OF THE WATER-SATURATED PORE VOLUME
AREA OF HIGH PREFLUSH CONCENTRATION 50-100% OF THE WATER-SATURATED PORE VOLUME

FIGURE 27

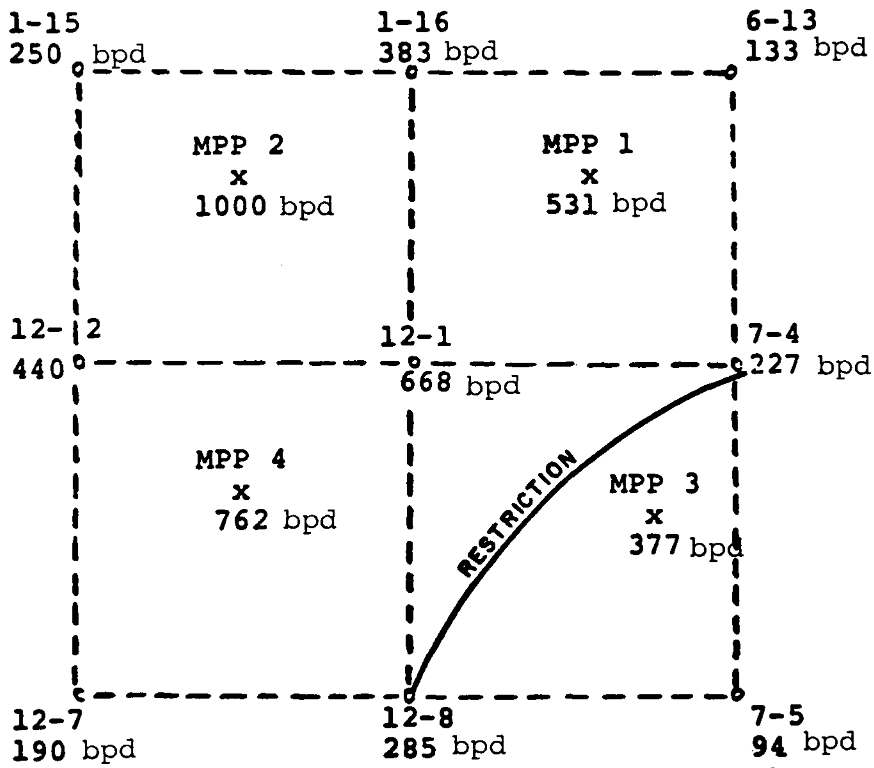
FIGURE 28

Preflush Pattern Balance Simulation

CASE 2

SYMMETRICALLY BALANCED
WELL RATES

ALL SURROUNDING CURRENTLY ACTIVE
WELLS ARE INJECTING & PRODUCING



TRACER OR PREFLUSH
BREAKTHROUGH TIMES

Pilot Wells	Field Tracer (Days)	Simulated Preflush (Days)
1-15	< 100	90-130
1-16	90	> 130
6-13	< 50	30-60
12-2	None	None
12-1	50-100	90-130
7-4	0-50	90-130
12-7	60-90	15-30
12-8	15-30	15-30
7-5	< 50	30-60

TOTAL 160-ACRE
PILOT RATES

Injection: 2670 bpd
Production: 2670 bpd

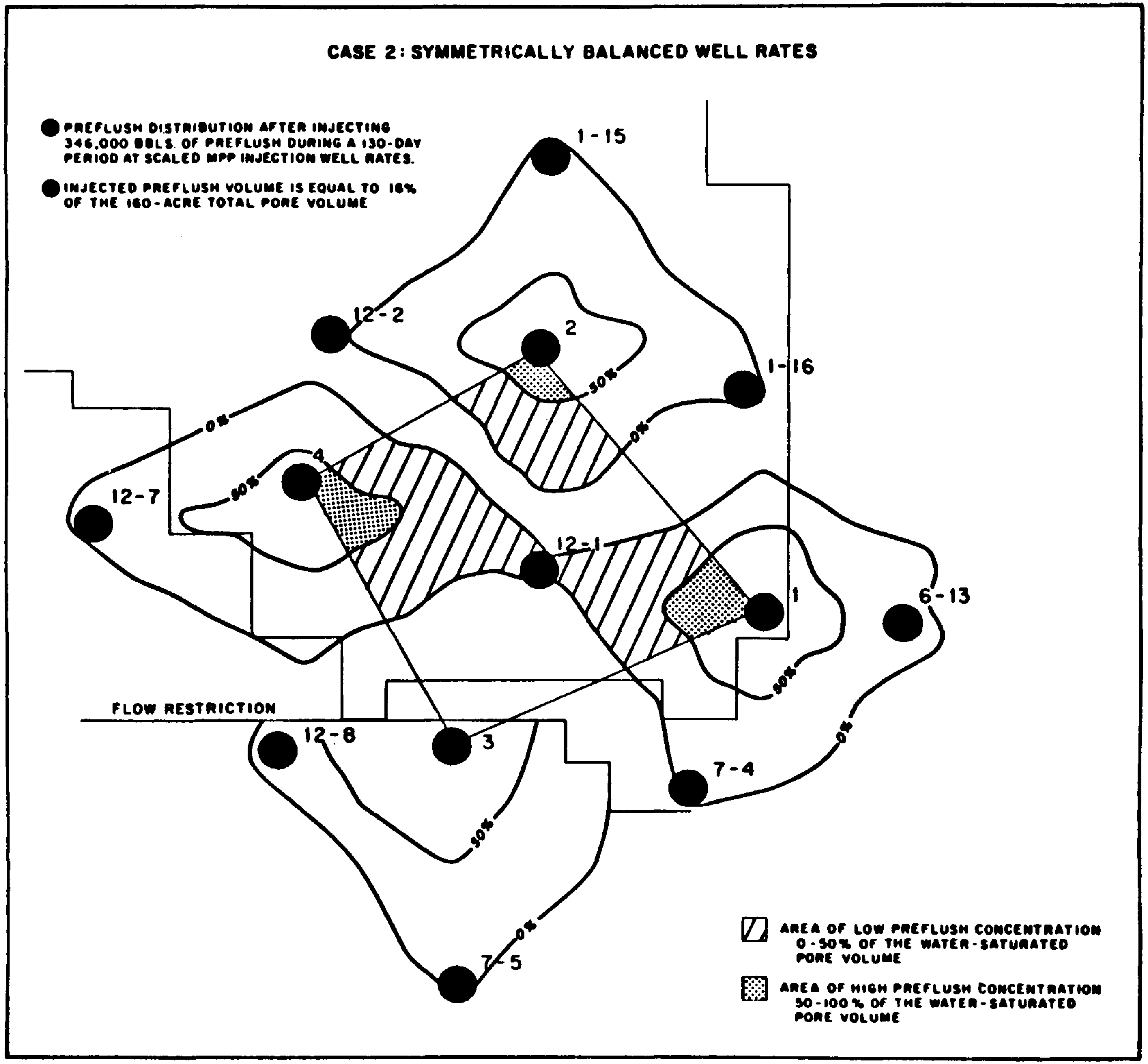
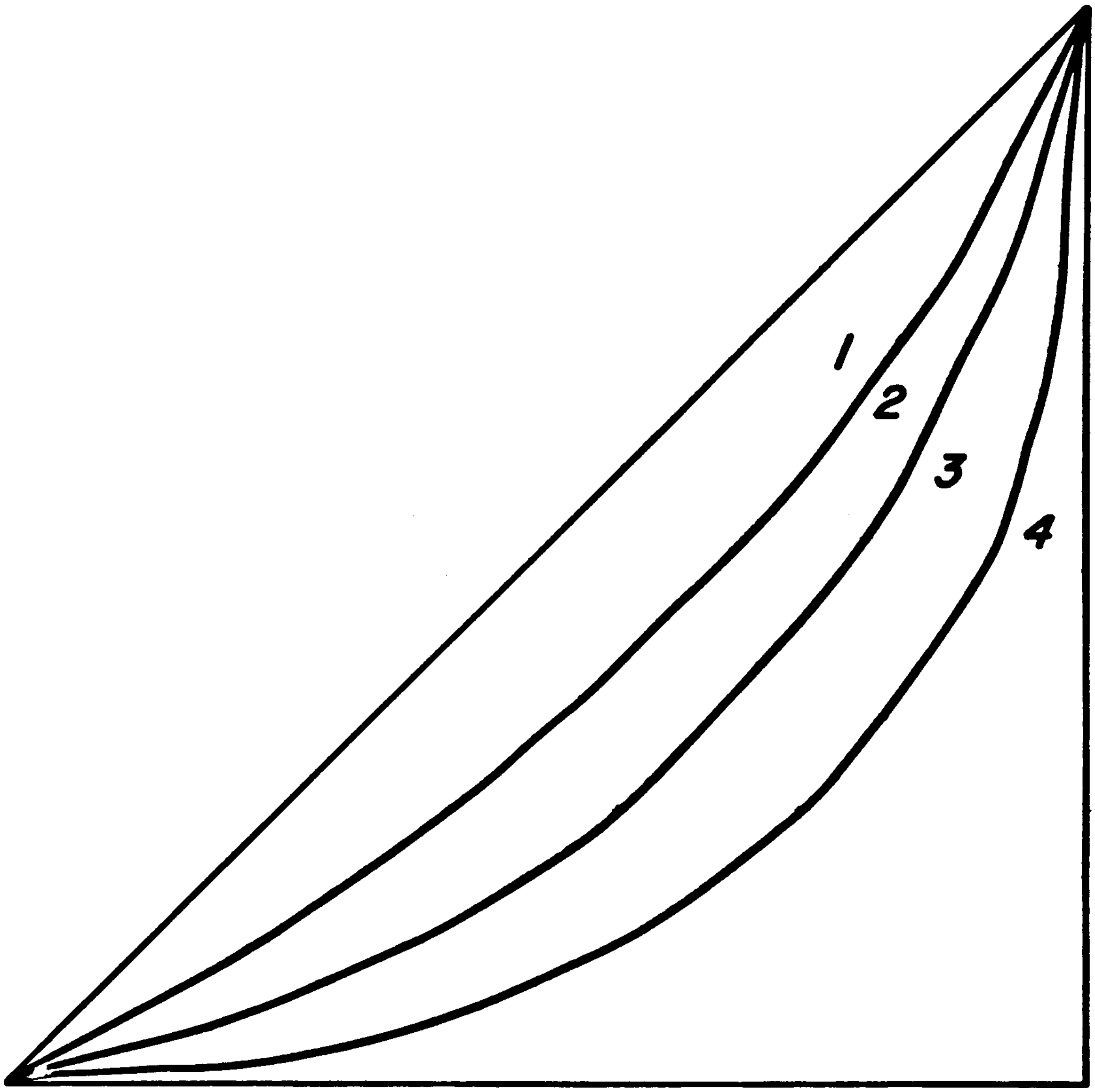

CASE 2: SYMMETRICALLY BALANCED WELL RATES
PREFLUSH DISTRIBUTION AFTER INJECTING 346,000 BBLS. OF PREFLUSH DURING A 130-DAY PERIOD AT SCALED MPP INJECTION WELL RATES.
INJECTED PREFLUSH VOLUME IS EQUAL TO 16% OF THE 160-ACRE TOTAL PORE VOLUME
1-15
12-2
2
1-16
4
12-7
12-1
1
6-13
FLOW RESTRICTION
12-8
3
7-4
7-5
0%
50%
AREA OF LOW PREFLUSH CONCENTRATION 0-50% OF THE WATER-SATURATED PORE VOLUME
AREA OF HIGH PREFLUSH CONCENTRATION 50-100% OF THE WATER-SATURATED PORE VOLUME

FIGURE 29

FIGURE 30

STREAMTUBE PATTERN



660 FEET

FIGURE 31

PILOT AREA STREAMLINE DISTRIBUTION

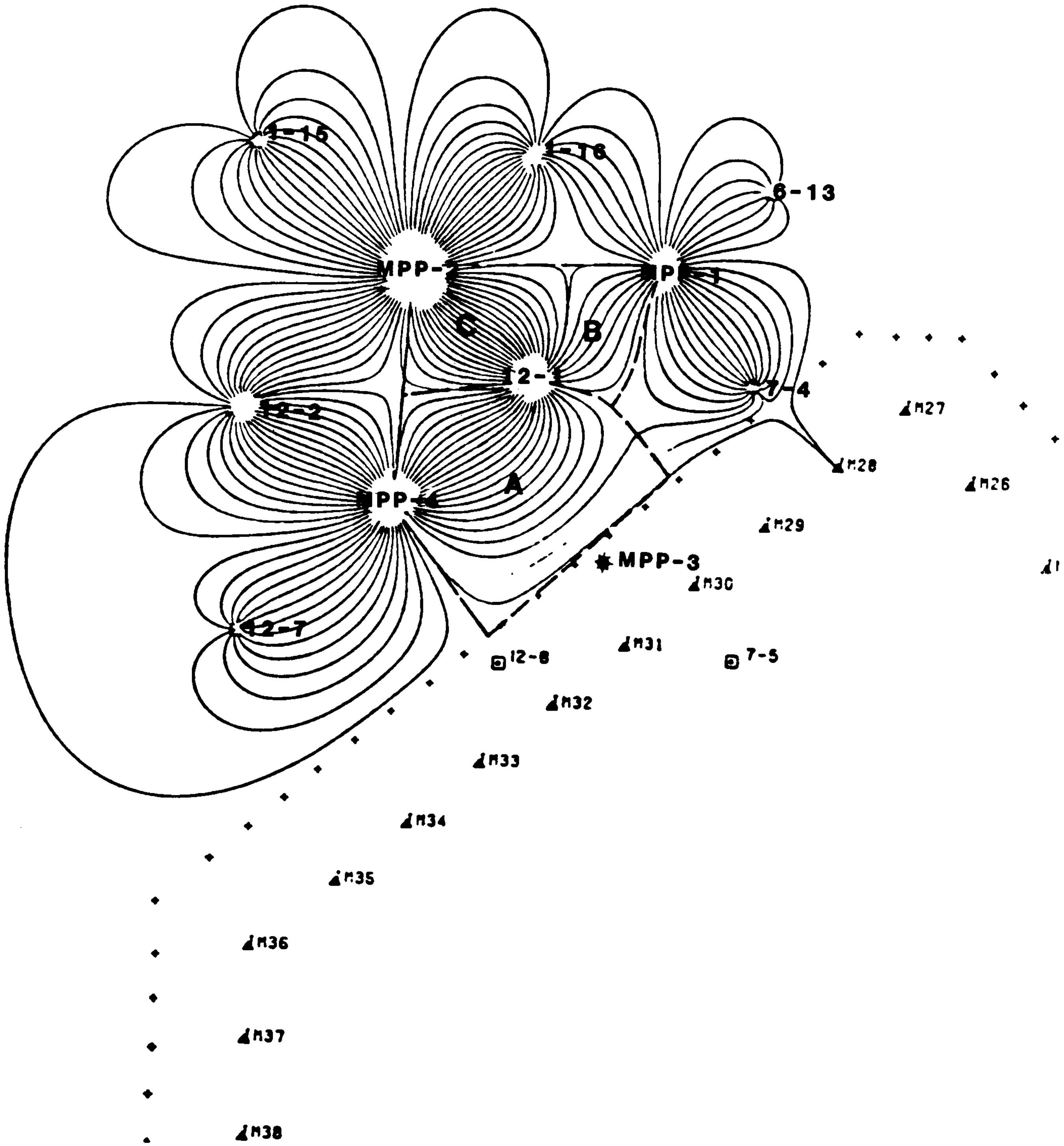


FIGURE 32

**FLUID STREAMLINE DISTRIBUTION NEAR WELL 12-1
(MULTIPLE LAYER PROTOTYPE)**

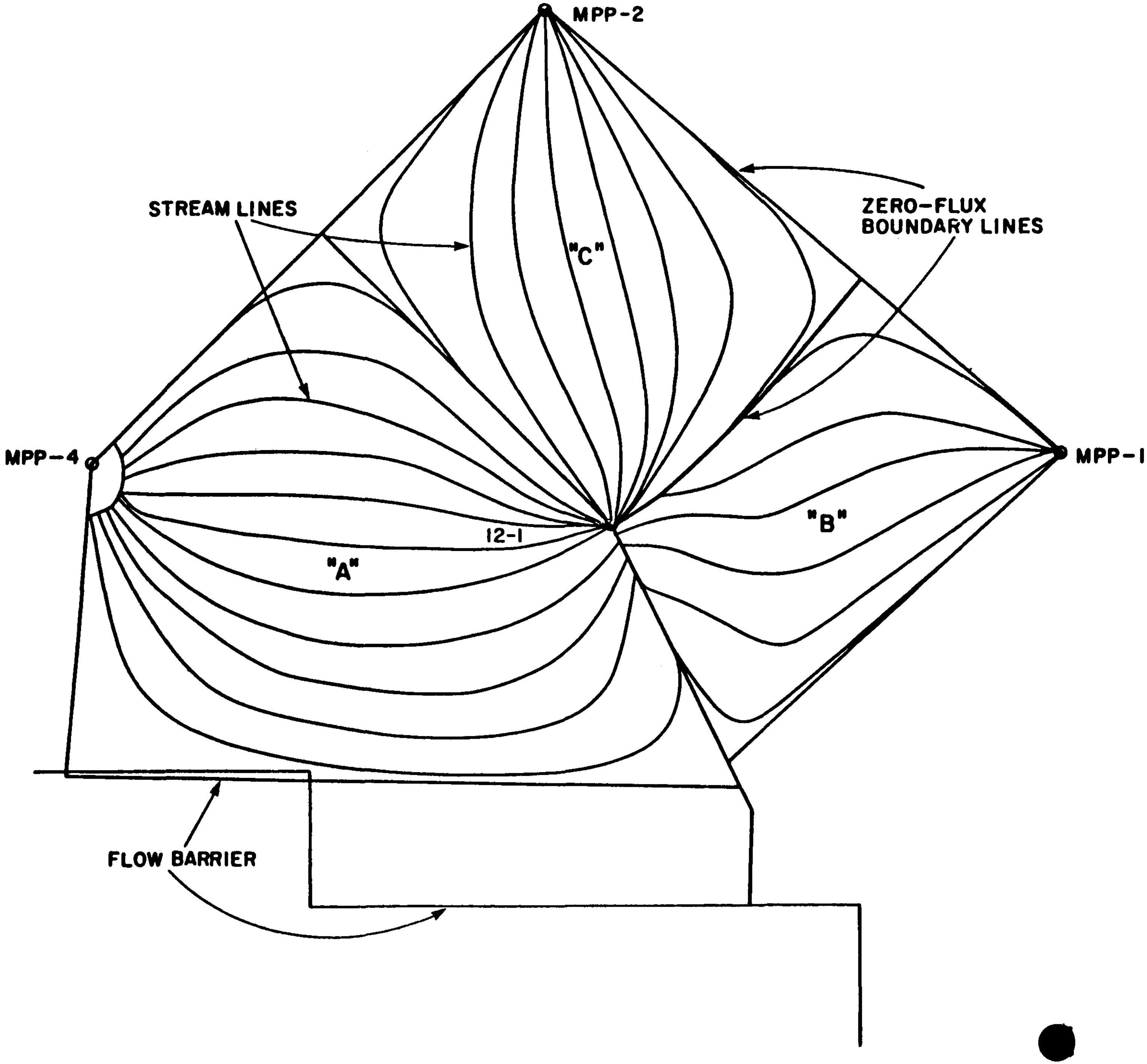
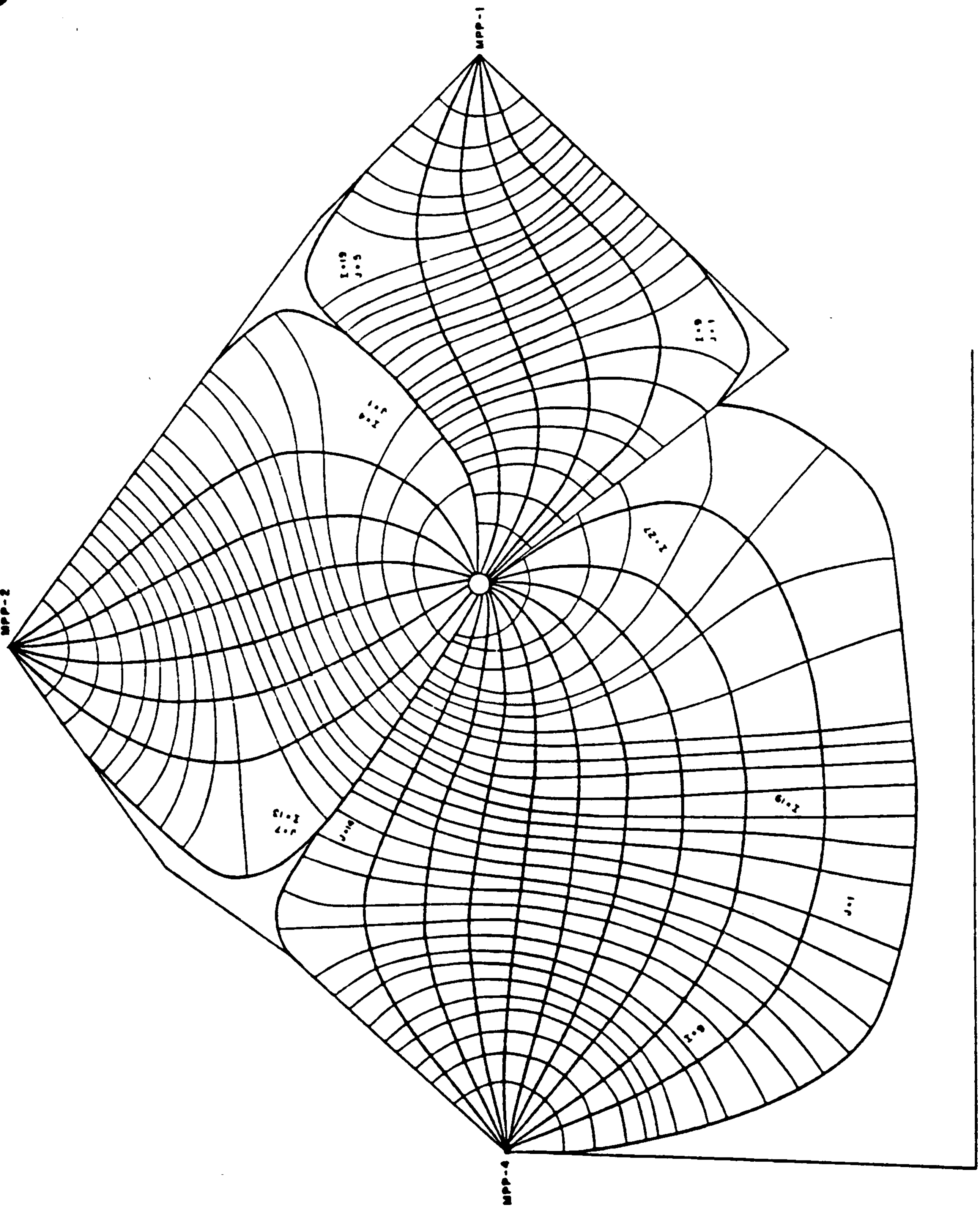


FIGURE 33

NUMERICAL GRID FOR CHEMICAL FLOOD SIMULATIONS



AT START OF PREFLUSH

INITIAL OIL SATURATION DISTRIBUTION NEAR WELL 12-1
(MULTIPLE LAYER PROTOTYPE)

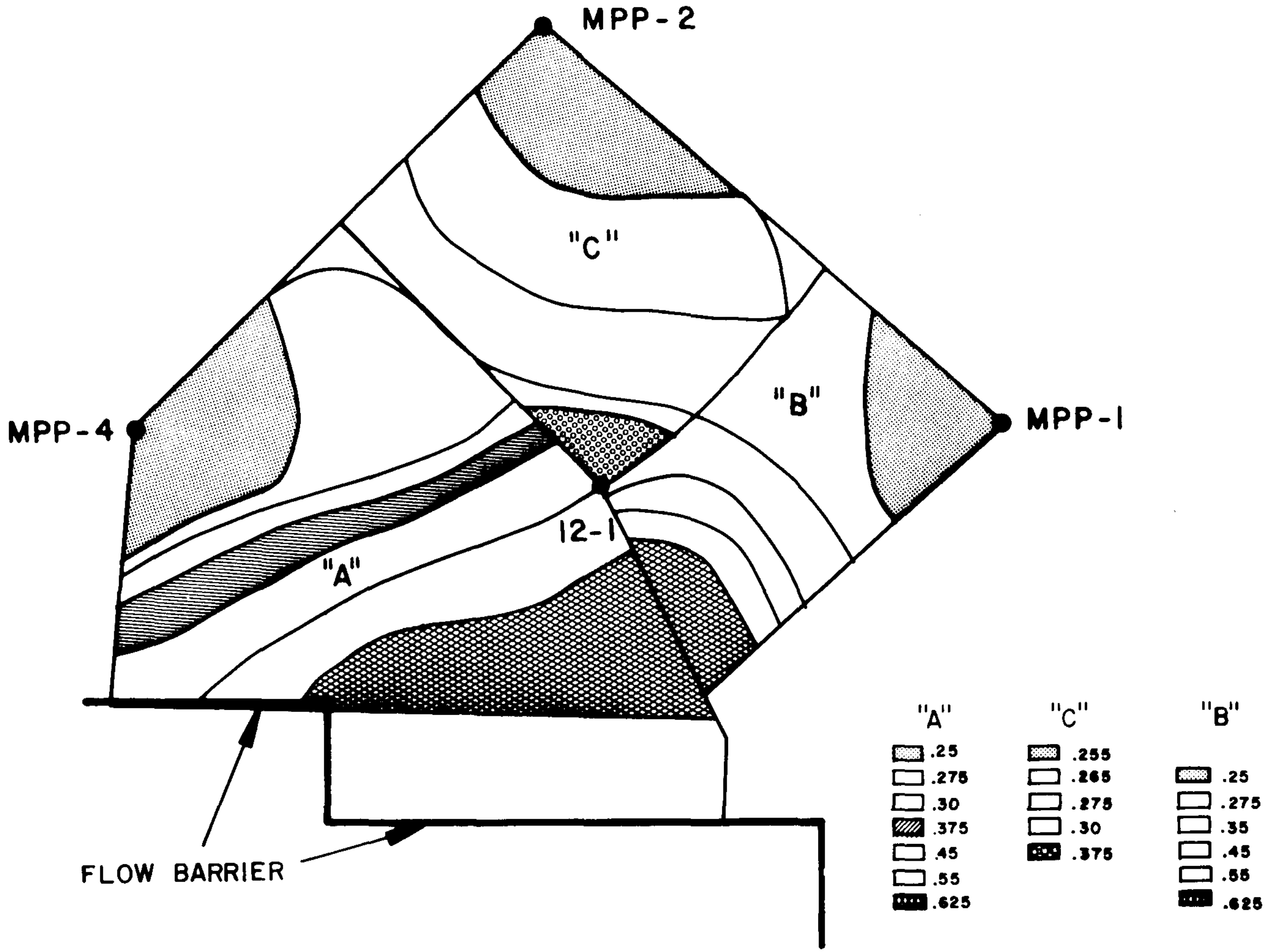


FIGURE 34

CHEMICAL FLOOD INCREMENTAL PRODUCTION
WELL 12-1

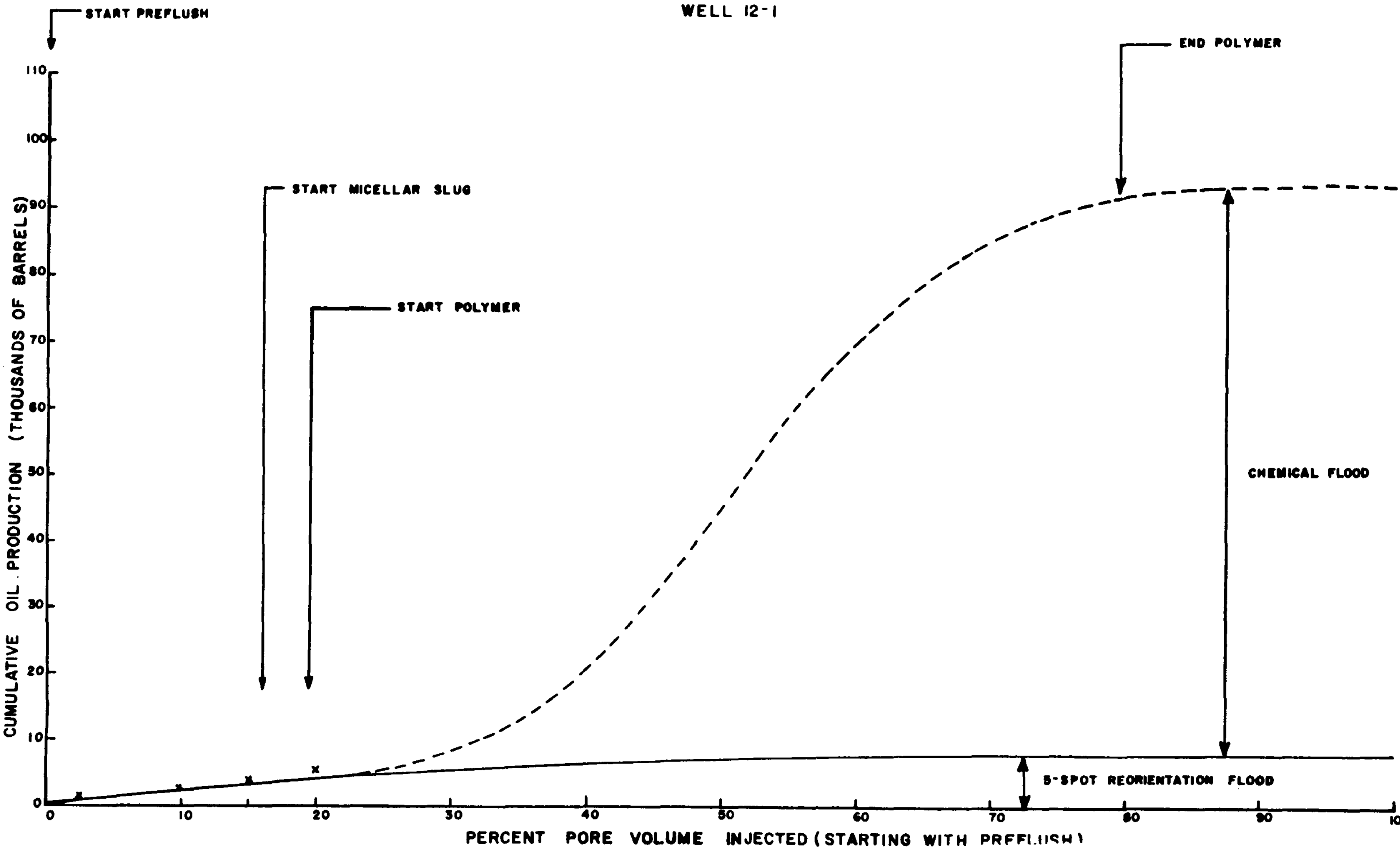


FIGURE 35

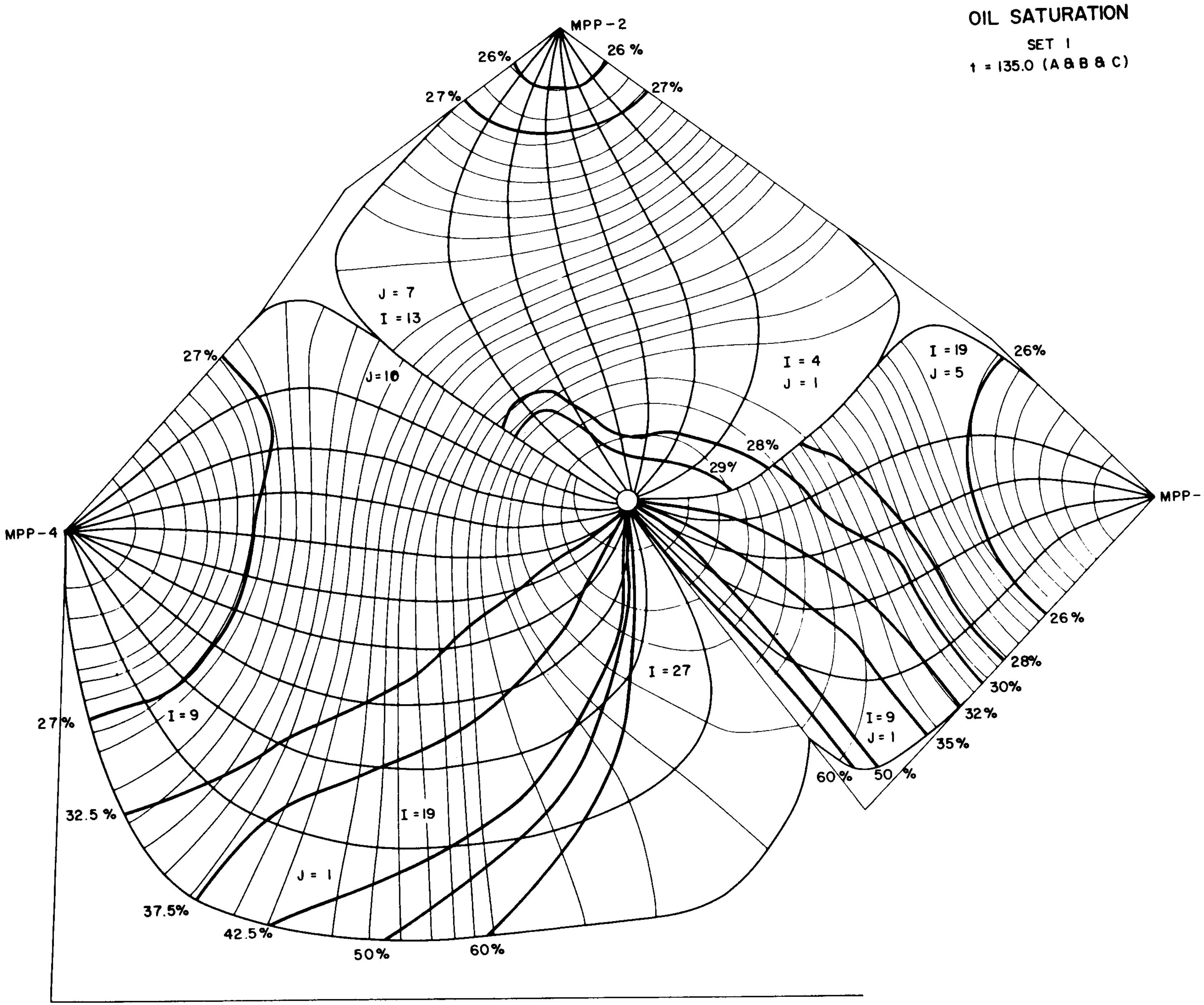

OIL SATURATION
SET 1
t = 135.0 (A & B & C)
MPP-1
MPP-2
MPP-4
26%
27%
28%
29%
30%
32%
35%
50%
60%
32.5%
37.5%
42.5%
J = 7
I = 13
J=10
I = 4
J = 1
I = 19
J = 5
I = 27
I = 9
I = 19
J = 1
I=9
J=1

Figure 36

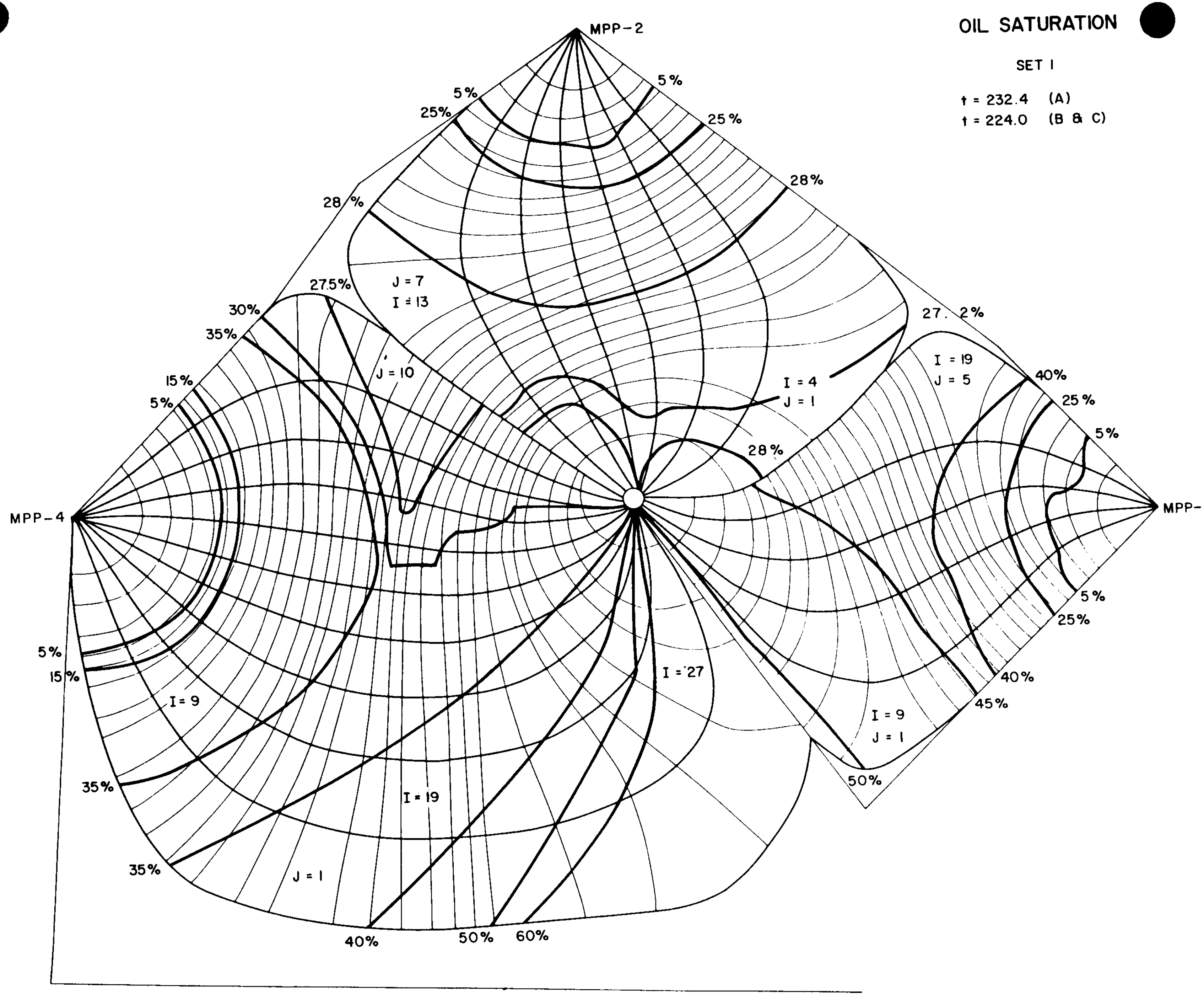

OIL SATURATION
SET I
t = 232.4 (A)
t = 224.0 (B & C)
MPP-2
MPP-1
MPP-4
5%
25%
28%
27.5%
30%
35%
15%
5%
J = 7
I = 13
J = 10
I = 4
J = 1
27. 2%
I = 19
J = 5
40%
25%
5%
28%
5%
25%
40%
45%
I = 9
J = 1
50%
I = 27
5%
15%
I = 9
35%
I = 19
35%
J = 1
40%
50%
60%

Figure 37

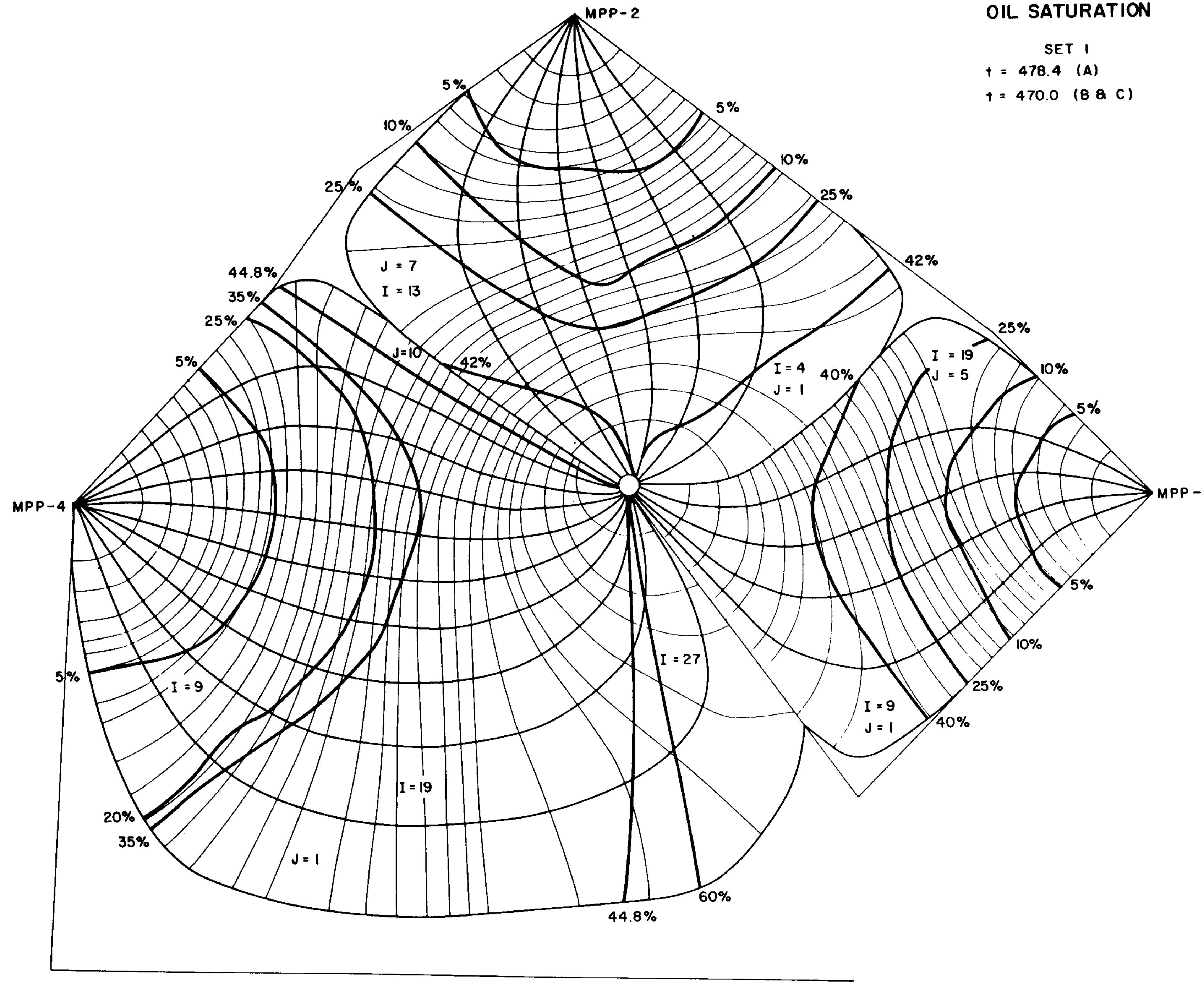

OIL SATURATION
SET 1
t = 478.4 (A)
t = 470.0 (B & C)
MPP-2
MPP-1
MPP-4
5%
10%
25%
42%
44.8%
35%
25%
5%
J = 7
I = 13
J=10
42%
I = 4
J = 1
40%
I = 19
J = 5
25%
10%
5%
5%
10%
25%
40%
I = 9
J = 1
I = 27
5%
I = 9
I = 19
J = 1
20%
35%
44.8%
60%

Figure 38

OIL SATURATION

SET 1

t = END

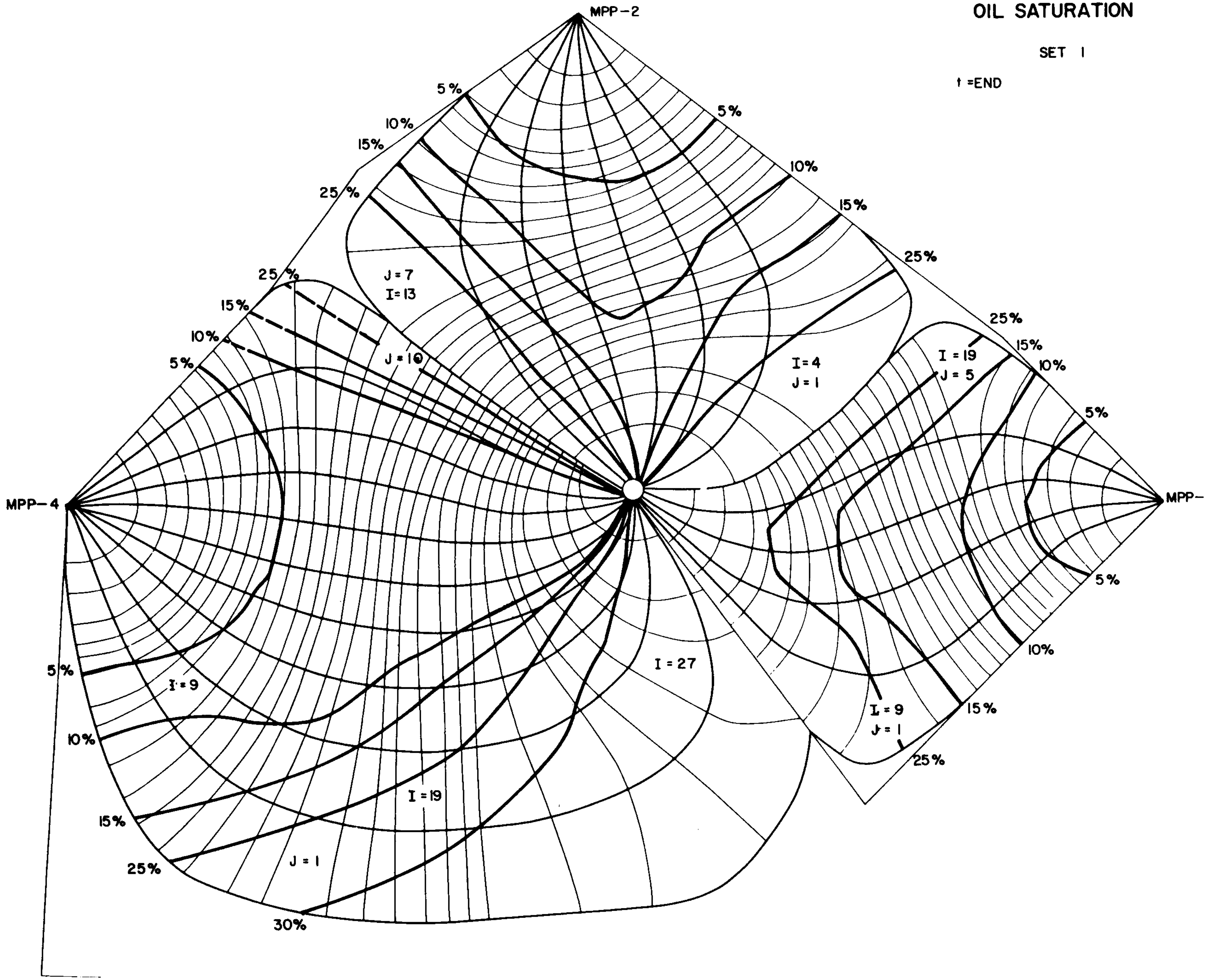


Figure 39

TIME LINE - BELL CREEK PILOT

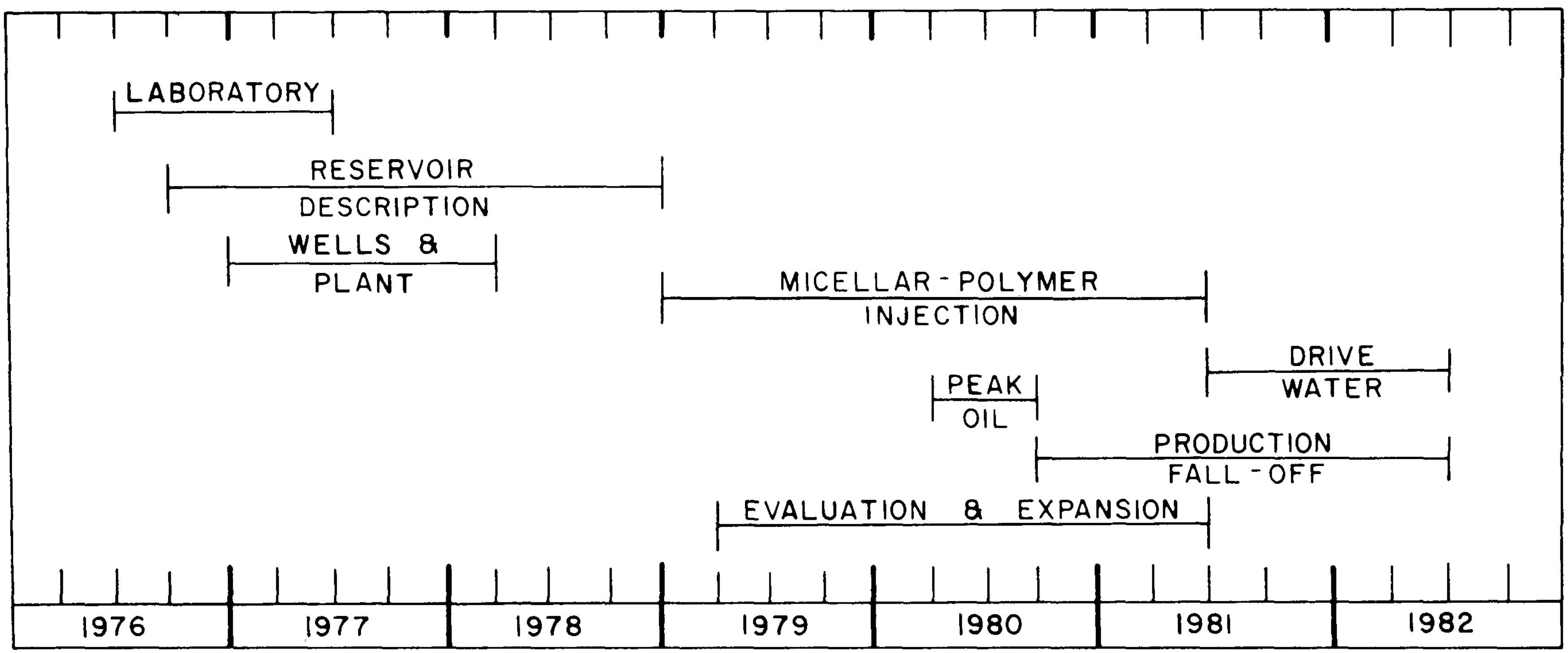


FIGURE 40

☆ U.S. GOVERNMENT PRINTING OFFICE: 1980—671-115/33