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STEWART RANCH POLYMER FLOOD

FEASIBILITY STUDY

By

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ER-1429

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ABSTRACT

A reservoir engineering study was made to determine the feasibility of polymer flooding the Stewart Ranch Field.

Correlations were made between core porosity and sonic-log travel time to calculate the porosity from sonic logs for all wells in the field. A correlation between porosity and permeability from core data was used to determine the permeability in all wells. The Archie equation was used to calculate the water saturations.

These data, along with special core and fluid analyses, were used in a 2-D, five-spot mathematical model and a front-tracking model to determine the feasibility of polymer flooding.

This study indicates that polymer flooding will recover an additional 3,466,590 bbl of oil with a net profit of $5,071,456 more than could be attained by conventional waterflood.

CONTENTS

CONTENTS

LIST OF FIGURES

ACKNOWLEDGMENTS

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The author wishes to thank National Cooperative Refinery Association, Unit Operator of the Stewart Ranch Unit, and Dow Chemical Company for making available the data for this study.

INTRODUCTION

For many years waterflooding has been the main secondary recovery method used to obtain additional oil from oil reservoirs. Recent advancements in technology have brought forth new secondary recovery techniques which will recover more oil than was previously feasible. One of these techniques is the addition of a partially hydrolyzed polyacrylamide polymer to the injection water of a waterflood. This technique is commonly referred to as polymer flooding. The polymer imparts an abnormal resistance to the flow of water through porous rock which results in an increase in oil recovery. Reservoirs containing a low-gravity crude and/or having a high vertical permeability variation are prospective candidates for polymer flooding. The Stewart Ranch Field contains a low-gravity crude (21.8° API) and has a moderately high vertical permeability variation of 0.625. A reservoir engineering study has been made to determine the feasibility of polymer flooding this field.

GEOLOGY AND HISTORY

The Stewart Ranch Field is on the eastern flank of the Powder River Basin approximately 5 miles northeast of Roset, Wyoming. The oil productive zone is the Minnelusa B sandstone of Permian age.

Regional Geology

The Minnelusa Formation is related to the transgression of a sea which advanced into the Powder River Basin from the southeast and southwest. The Minnelusa sedimentation was a result of the erosion of the Ancestral Rockies to the south and the Montana Highlands to the north. This shallow sea environment and a series of transgressions and regressions led to the deposition of sandstone, carbonate, and evaporite rocks (Tenney, 1966, p. 227-250).

A variety of traps was formed in the Minnelusa Formation. Post-Minnelusa folding caused structural traps. Pre-Opeche erosion and the subsequent infilling of Opeche Shale in topographic lows caused unconformity traps. Stratigraphic traps were formed as a result of lateral facies changes from oil-bearing sandstone to tight dolomitic sandstone and eventually to dense dolomite or anhydrite. Figure 1 illustrates the common traps found in the Minnelusa (Berg, 1963, p. 168-176).

There are three main sandstone members in the Minnelusa regionally referred to as the A, B, and C sandstones, with the A sandstone the uppermost member. Oil production has been found in porous Minnelusa dolomites and Lower Minnelusa sandstones, but most of the oil has been produced from the upper two sandstones. In the eastern Powder River Basin, the upper Minnelusa contains a large percentage of sandstone. These sandstones have been the primary objective of Minnelusa wildcat drilling in this area.

Regional History

The first Minnelusa oil in the Powder River Basin was discovered in 1909 and led to the development of the Rocky Ford Field in Crook County, Wyoming. The main exploration technique used during these early years consisted of finding an anticline, mapping it by surface methods, and drilling if structural closure appeared to be present. Most of this type exploration was limited to the northern part of the basin where the Minnelusa Formation is at shallow depths.

By the late 1940's seismic methods focused attention on the deeper parts of the basin. Structural closures were still the main drilling targets.

During 1960 the discovery of the Raven Creek Field proved to be of major geologic significance. Development drilling in the field indicated the presence of a stratigraphic trap. The productive sandstone is not present updip, and its interval is occupied by abnormally thick Opeche Shale. This occurrence led to the theory that the non-existence of the sandstone was a result of pre-Opeche erosion and the subsequent infilling of Opeche Shale in topographic lows.

Unconformity traps were formed where a porous sandstone was truncated on the updip side by this erosional surface. One of the main exploration techniques used today is accurate mapping of the Opeche Shale thickness (Trotter, 1963, p. 117-122).

Stewart Ranch Field Geology

The Stewart Ranch Field is an example of an unconformity trap with pre-Opeche erosion truncating the oil-productive Minnelusa B sandstone on the northwest, north, east, and southeast sides. An oil-water contact limits the oil zone on the southwest. Figure 2 is an isopachous map of the Opeche Shale. An Opeche Shale thickness of 80 to 100 ft usually indicates truncation of the oil-productive sandstone.

Minor facies changes are evident as the sandstones alternate laterally with sandy dolomite and dolomite across the field. The sandstone is separated into two noncommunicating units in the central part of the field. The upper unit is predominant throughout the field. The lower unit represents a small percentage of the total field; it will not be included in this polymer feasibility study.

Figure 3, a structure map of the top of the Minnelusa, is a reflection of the erosional-surface topography and regional dip. A structure map on the base of the Minnelusa was not made inasmuch as none of the wells penetrated the entire Minnelusa section, and no consistent marker bed was found in the interval that was penetrated. There appear to be no structural abnormalities other than the normal westerly dip of approximately 150 ft per mile.

The productive sandstone is tan, very fine to medium grained, silty, and shale laminated. Examination of vertical sections of core revealed some horizontal shale laminations, very little crossbedding, and no natural fractures.

Stewart Ranch Field History

The Stewart Ranch Field was discovered in November, 1965, with the drilling of the United States Smelting, Refining and Mining well 1 Stewart (now Unit 3) located C SW/4 SE/4 Sec. 3, T50N-R69W. This well tested 360 BOPD (barrels oil per day). Its drill-stem test indicated an initial reservoir pressure of 3195 psig. Development rapidly progressed through December, 1966, with the drilling of 20 additional producing wells and 6 dry holes. The south end of the field was drilled on 80-acre spacing followed by the development of the north end on 40-acre spacing.

Initial producing rates ranged from 70 BOPD to 932 BOPD. A peak average production rate of 3230 BOPD was made in September, 1966. Fracturing or acidizing techniques were used to attain satisfactory producing rates in several wells. Most of the wells have never been stimulated.

The principle reservoir energy has been fluid and rock expansion. The limited source of energy made it necessary to consider secondary recovery techniques in order to recover additional oil. The field was unitized November 1, 1970, for the purpose of secondary recovery by waterflooding. Before unitization the field had produced 1,989,246 bbl of oil and 531,373 bbl of water. No gas production has been reported. Field tests indicate that very little gas is being produced with the oil.

Water injection began November 25, 1970. Seven peripheral wells were converted to water injection (Figure 6). The injection water pumped from the Fox Hills Formation is fresh, with a total solids content of 751 mg per l. Tests were run to assure the compatibility of this water with the Minnelusa B formation water. Eight hundred thirty thousand bbl of water had been injected by the end of May, 1971. Injection pressures ranged from 0 to 2200 psig.

Figure 8 is the production history of the field. Excellent response in oil production had been achieved with no water breakthrough. Production response has been seen in all the producing wells. This response indicates that communication exists throughout the field.

The water-injection plant consists of 3 positive-displacement pumps with a combined capacity of 9000 bbl per day at a discharge pressure of 3000 psig. By the end of May, 1971, the plant was operating at a volume of 6000 bbl water per day, with a discharge pressure of 2600 psig. The water supply is limited by the capacity of the water-supply well.

RESERVOIR PARAMETERS

Sonic logs, gamma-ray logs, and dual-induction laterologs are available on all wells in the Stewart Ranch Field. Ten of these wells were cored, and seven were successfully drill-stem tested. All of these data were examined in detail to obtain necessary reservoir parameters for this polymer feasibility study.

Porosity

The porosity, as determined from core analysis, was correlated with the sonic travel time from the sonic log for each of the cored wells. It was necessary to adjust the reported core depth to match the appropriate log depth for most wells. A relationship between core porosity and sonic travel time was established from a plot of these two values. This plot is shown in Figure 9.

The data plotted in Figure 9 is considerably scattered. The least-squares method of curve fitting a straight line to these data was made, but the resulting line indicated values of rock and fluid travel-time velocities that were not characteristic of the Minnelusa sandstone in this region. Because of the data scatter and the lack of a satisfactory coorelation using the least-squares technique, the values for rock velocity (19,500 ft per sec) and fluid velocity (5300 ft per sec) characteristic of the Minnelusa sandstone in this region were used to construct the line shown on Figure 9. This line resulted in what appears to be a reasonable fit of the data. The porosity in each well was determined on a 1-ft interval from digitized sonic log data with the use of this straight-line relationship.

The cores from 9 of the 10 cored wells were analyzed to determine porosity, permeability, residual oil saturation, and water saturation. A total of 174 core samples from the oil-productive Minnelusa sandstone were analyzed by commercial laboratories. This represents about 19 percent of the total interval drilled in the field.

The average porosity of all core samples is 17.0 percent. The porosity calculated from the sonic logs for the corresponding cored intervals average 17.2 percent.

The average core porosity deviated no more than 20 percent from the calculated sonic log porosity in all cored wells. The average porosity of all core samples agrees very closely with the calculated sonic log porosity. Therefore, the calculated sonic log porosity was used for all wells in the field.

The calculated porosity ranges from an average of 12.1 percent in well 1 to 19.9 percent in well 12. The field average porosity is 16.3 percent.

Water Saturation

The water saturation in the oil-productive reservoir was calculated from the dual-induction laterologs and sonic logs through the use of the following empirical relationships developed by Archie (1942, p. 54):

$$F = \emptyset^{-m}$$

$$S_w = (FR_w/R_t)^{1/n}$$

where S_w = Water saturation

F = Formation resistivity factor

R_w = Formation water resistivity

R_t = Total formation resistivity

$\emptyset$ = Porosity

m = Cementation exponent

n = Saturation exponent

The formation water resistivity (R_w) was determined from water analyses to be 0.029 ohm-meters at the bottom-hole temperature of 136° F.

A saturation exponent (n) of 2.0 was used. This value is generally used by logging companies in the calculation of water saturation in sandstones.

The total formation resistivity (R_t) was determined from the deep induction curve on the dual-induction laterolog. These data were digitized on a 1-ft interval to correspond with the digitized porosity data from the sonic logs. Allowance was made for the influence of adjacent formations on the resistivity readings.

The cementation exponent (m) is determined from the slope of log R_t plotted against log $\emptyset$ for a constant water saturation. A cementation exponent of 1.81 was determined from this plot with the use of the log data from intervals that tested 100 percent water. This value was also checked by data from the Minnelusa C sandstone, which is known to contain 100 percent water in this area.

The water saturation (S_w) was calculated with a computer program using the digitized data. The average water saturation ranges from 36.7 percent in well 10 to 17.2 percent in well 12. The initial water saturation in the field averaged 26.4 percent.

Permeability

The horizontal air permeability (K) as determined from core analysis was correlated with the core porosity. A least-squares technique was used to determine the best straight-line fit of the log K versus Ø plot (Figure 10). An attempt to reduce the data scatter was made by plotting log $K/Ø^2$ versus Ø and log $Ø^2/K$ versus Ø with no success.

The average permeability of the core samples is 157 md (millidarcys). The average permeability calculated from the porosity--permeability relationship for the same cored interval is 159 md. Reasonable agreement between core permeability and calculated permeability exists in all cored wells.

The porosity--permeability relationship was used to determine the permeability on a one-foot interval for each well. The calculated permeability ranges from 16 md in well 1 to 318 md in well 12. The permeability throughout the field averaged 92 md.

Permeability Variation

The permeability variation for all wells was calculated with the method described by Dykstra and Parsons (1950, p. 160-173). The average permeability variation of the core permeability is 0.642. This value compares with a permeability variation of 0.615 for the calculated permeability on the cored wells. The average permeability variation for all wells in the field using the calculated permeability is 0.625.

Relative Permeability

Four core samples with permeabilities ranging from 28 md to 409 md were selected for relative permeability analysis. Excellent agreement in relative permeability is exhibited by the four samples. Figure 11 is the water-oil relative permeability curve for a 90-md sample used in this study.

Net Pay

The net pay includes all sandstone in the Minnelusa B with a water saturation less than 51 percent and a porosity greater than 10 percent.

The water saturation of 51 percent corresponds to a fractional flow of water of 98 percent. A fractional flow of water of this magnitude is considered noncommercial.

The porosity of 10 percent corresponds to a permeability of approximately 8 md. The core samples with permeability less than 8 md represent less than 1 percent of the total transmissibility.

A net-pay isopachous map of the Minnelusa B sandstone is shown in Figure 4. Figure 5 is an isopachous map of the hydrocarbon pore volume. The values for this map are calculated by multiplying the net pay by the product of porosity times oil saturation. Both of these maps are similar in appearance. The north end of the field has a greater net-pay thickness and oil accumulation than the south end. The net pay volume in the field is 48,187 ac-ft.

RESERVOIR FLUID STUDIES

A reservoir fluid analysis is of major importance in a polymer feasibility study. Although an analysis of the reservoir fluid in the Stewart Ranch Field was not made, a fluid analysis from a nearby field with similar crude-oil characteristics is available. The fluid analysis available is for a 21.5° API crude at 139° F as compared with the 21.8° API crude and a bottom-hole temperature of 136° F in the Stewart Ranch Field. The viscosities at 139° F are identical in the two fluids.

The fluid analysis indicates a bubble point of 186 psig and gas in solution of 14 cu ft per bbl. Figure 12 is a tabulation of the fluid-analysis data. The oil formation-volume factor is 1.026 at original reservoir pressure (Figure 13). The crude-oil viscosity ranges from 24.95 cp at original pressure to 17.0 cp at bubble-point pressure (Figure 14).

PRESSURE HISTORY

The drill-stem test of the field discovery well (Unit 3) indicated a virgin reservoir pressure of 3195 psig. No pressure surveys were run in the field until November, 1970. At this time the entire field was shut in for 96 hr. Bottom-hole pressure bombs were run in 6 wells, and fluid levels were shot on 16 wells.

The areal weighted pressure in the reservoir was approximately 900 psig. The pressure in the southern part of the field was more than 1000 psig, and the pressure in the northern part was under 500 psig. The difference in pressure is the result of closer well spacing and greater cumulative production per ac-ft in the north end. Also, the south end may be receiving some energy from the aquifer and from a communicating casing leak in well 5.

A pressure build up in well 3 indicated that the reservoir pressure had not stabilized during the shut-in period. Although the pressure was not stabilized, the magnitude and distribution of pressure appeared to be the important factors to be ascertained from the survey.

CALCULATION OF ORIGINAL OIL IN PLACE

The original oil in place was determined by volumetric measurement. A material balance calculation was also made as a check.

Volumetric Calculation

A hydrocarbon pore-volume map was constructed with the use of the calculated reservoir parameters (Figure 5). The volume was calculated by planimetering the areas inside the isopach lines and using the trapezoidal formula. This value was divided by the initial oil formation-volume factor to convert the volume to surface units. The original oil in place was calculated to be 43,797,000 stock tank bbl.

Material-Balance Calculation

Since the reservoir appeared to be above the bubble point in November, 1970, the original oil in place was calculated by the following formula:

$$N = (N_p/C_e \Delta P)(B_o/B_{oi}) + (W_p B_w - W_e) / (C_e \Delta P B_{oi})$$

where N = Original oil in place

N_p = Oil production

ΔP = Pressure drop

B_o = Current oil formation-volume factor

B_{oi} = Initial oil formation-volume factor

W_p = Water production

W_e = Water influx

B_w = Water formation-volume factor

C_e = Effective fluid compressibility

The reported cumulative production prior to the November 1970 shut in was 1,989,246 bbl oil and 531,373 bbl water. Most of the water production is believed to be from formations other than the Minnelusa B sandstone. If the water production and water influx are neglected, the original oil in place is calculated to be 56,069,000 stock tank bbl. A net water influx of only 452,000 bbl would cause the material-balance calculated oil in place to equal the volumetric calculated oil in place.

The material balance helps verify the fluid-analysis data in that the reservoir pressure appears to be above the bubble point. It also indicates that only minor natural water influx has occurred.

POLYMER FLOOD ANALYSIS

Oil recovery from certain high-gravity crude-oil reservoirs has historically been poor. Even with successful waterflooding, 80 percent or more of the oil may remain in the reservoir. Polymer flooding is a relatively new process used in certain oil reservoirs to recover a higher percentage of the oil in place.

Theory and History

The polymer chemical consists of very long chains of acrylamide. (Other types of polymers exist but will not be reviewed in this study). These acrylamide chains may result in molecular weights in the 3 to 12 million range. They thicken water and increase its resistance to flow in porous rock.

Hydrolysis refers to the replacement of the acrylamide groups in the polymer chain by acrylate groups. Partial hydrolysis of the acrylamide polymer has several desirable effects. A certain amount of hydrolysis is known to reduce the loss of polymer in the reservoir rock. It also results in negative charges being spaced along the polymer chain. These negative charges repel each other and cause the polymer to be more stretched out (written correspondence, Jewett, R. L.).

A partially hydrolyzed polymer will cause an abnormal resistance to the flow of water through porous rock. This resistance to flow is abnormal in the sense that it is higher than would normally be expected from the viscosity increase that the polymer causes in the water.

The cause of this abnormal resistance is not clearly understood, but it may be the result of polymer entrapment in the pores causing reduced permeability or the interaction between molecular coulombic and ionic forces. The resistance of a certain concentration of polymer is the ratio of the measured mobility of water to the mobility of the polymer solution. The residual resistance is the ratio of the mobility of water before injection of the polymer solution to the mobility of water after injection of the polymer solution. Both the resistance and the residual resistance are of importance in the recovery of oil from a reservoir. An increase in the resistance results in a decrease in the mobility ratio and an increase in oil recovery.

The amount of polymer loss in the reservoir rock is referred to as adsorption. It is not known whether the loss of polymer is due to chemical adsorption, mechanical entrapment, or both. The adsorption is calculated from the difference in polymer concentration before and after being cycled through a core sample several times. The adsorption is dependent on the polymer type and the kind of reservoir rock (private correspondence, Jewett, R. L.).

There are two main applications of polymers in the recovery of additional oil. One is the injection of a small slug of polymer that has high adsorption properties. This type of treatment is used to improve the permeability distribution by lowering the permeability of the highly permeable sections of the reservoir rock. An improved permeability distribution results in a better vertical sweep efficiency and higher oil recovery. Another application is the injection of a large slug of polymer that has low adsorption properties in an effort to decrease the mobility ratio between the displacing and displaced phases. The decrease in mobility ratio results in better displacement efficiency and higher oil recovery.

The histories of polymer floods initiated during 1964-1969 were analyzed by R. L. Jewett (1969). Of the 61 polymer-flood projects analyzed, 14 indicated encouraging results, 31 were failures, and 16 were too recent to evaluate. Of the failures, 16 were classified as unsuitable reservoirs, 13 were explained on other reasonable bases, and 2 had no explanation. This analysis indicates that careful examination of prospective polymer-flood projects is necessary to eliminate possible failures.

Method of Calculation

Several methods are used to determine the feasibility of polymer flooding an oil field. Wang and Caudle (1970) present a streamline model based on steady-state flow. Graue (1968) predicted polymer flood results with a linear, layered reservoir model. Patton, Coats, and Colegrove (1969) used a layered streamline mathematical model to predict polymer-flood performance. Jewett and Shurz (1969) present a computer program based upon a 2-D, 2-phase, noncommunicating-layer mathematical model in which the flow is governed by the Buckley-Leverett fractional flow equation.

The five-spot version of the mathematical model described by Jewett and Schurz was made available by Dow Chemical Company for use in determining the feasibility of polymer flooding the Stewart Ranch Field.

The mathematical model consists of a confined five-spot system with a series of noncommunicating layers which may vary as to absolute permeability, porosity, thickness, and fluid saturations. Each layer is divided into 10 equal-volume concentric rings.

A single set of water-oil relative permeability curves governs the flow in accordance with the Buckley-Leverett fractional-flow theory and the Darcy radial-flow equation. The water and oil banks are assumed to be radial until water breakthrough in the manner described by Deppe (1961, p. 81). The areal-sweep efficiency after water breakthrough follows the model data of Caudle and Witte (1959, p. 446), in which the sweep efficiency is a function of mobility ratio and displaceable pore volumes injected.

The calculation procedure starts with the injection of a small amount of fluid into the system. Each layer will accept a portion of the injected volume based on the ratio of the conductivity of the individual layer to the total conductivity. The conductivity used in the model is a function of fluid saturation and distribution, flow geometry, and both absolute and relative permeability.

In a given layer, the injected volume enters the first segment. Fillup occurs until the injected volume equals the mobile gas volume. After fillup has occurred, the injected liquid expands the total volume of the segment. All liquids, assumed to be instantaneously mixed, flow out of the segment in accordance with the fractional flow curve until the segment returns to its original volume. This liquid flows into the second segment, and the process is repeated for all segments in the layer. No production is recorded until all the mobile gas saturation has been displaced.

All layers in the system are treated in the same manner as described above. After the injection of each small volume, the produced fluids from each layer are summed to give the total oil and water production for that volume step. The calculation continues for a pre-designated number of volume steps or until the water-oil ratio reaches a specified economic limit.

The above discussion describes the simulation of a conventional waterflood. For the simulation of a polymer flood, the model must incorporate the resistance, residual resistance, and adsorption properties of the polymer solution. For the simulation of the resistance to flow of the polymer solution, the water viscosity is multiplied by the laboratory-determined resistance factor. This in effect lowers the mobility ratio in proportion to the resistance factor.

The follow-up injected water undergoes a decrease in mobility due to the residual resistance factor. The residual resistance is taken into account by increasing the viscosity of the follow-up water by a factor equal to the laboratory-determined residual resistance for the reservoir rock.

Adsorption is also accounted for in the model. As the polymer enters a segment, instantaneous adsorption that occurs leaves a denuded fluid of equal volume with properties identical to those of the connate water. This denuded water combines with the connate water to form a water bank. This combination causes the water bank to move through the formation faster than the polymer bank. Adsorption continues until the adsorption requirements are met.

The polymer slug size and concentration are varied to arrive at the optimum cash flow. A specified amount of water can be injected before polymer injection to give a more accurate appraisal of polymer projects started after the initiation of a waterflood.

The program utilized in this study is for a confined five-spot pattern. The Stewart Ranch Field is being flooded with a peripheral pattern. The major difference in the two patterns is the theoretical areal sweep efficiency at water breakthrough and at various water cuts. At extremely high water-oil ratios, the areal sweep efficiency of both patterns are comparable. Therefore, the difference in patterns will have little effect on the recoveries at high water-oil ratios. A linear version of the program previously described was run for comparison with the five-spot system. The results for the waterflood case were very nearly the same. Additional runs for the polymer case with the linear system were not made.

The floodable reservoir volume was determined with a front-tracking technique. Figure 6 illustrates three phases in the front-tracking program. The initial phase assumes steady-state flow with all the present wells operating. Phase II assumes that wells 3, 5, 11, 16, 18, and 20 are shut in. Proposed wells 23 and 24 were drilled and put on production at the start of Phase II. Phase III assumes that wells 7. 13, 14, and 21 will be shut in. This leaves wells 6, 9, 12, 17, 23, and 24 producing until the end of the flood.

The areal-sweep efficiency was determined by planimetering the displaceable pore-volume map (Figure 7) to determine the percentage of displaceable pore volume inside the swept area illustrated in Figure 6. The areal-sweep efficiency is 83.9 percent.

Through the combining of the results of the mathematical model with the areal-sweep efficiency, the feasibility of polymer flooding the Stewart Ranch Field was determined.

Calculation of Oil Recovery

The reservoir and fluid data used in the calculations of the conventional waterflood and the polymer flood are given in Figure 15. Although the reservoir pressure is above the bubble point, a 3.85 percent gas saturation was used. This gas saturation made it possible for the model to allow for a period of pressuring up the reservoir. A material balance calculation indicated that a net injection of 0.0385 pore volumes was needed before steady-state conditions would exist. The allowance of a pressuring up period gave a more realistic approximation of the flood prediction.

The injection rate is expected to remain at 6000 bbl per day until the end of September, 1971. At that time it is anticipated that additional water will be available to increase the injection rate to 9000 bbl per day.

It was assumed that polymer would be injected after 1,750,000 bbl water were injected, some time about the end of October, 1971.

Analyses of cores from the Stewart Ranch Field were made to determine the resistance factor at various polymer concentrations (Figure 16). The residual resistance factor is 3.0. The adsorption ranges from very little to 50 lb per ac-ft.

Several computer runs were made to optimize the best polymer slug size and concentration. For the average data used, the optimum slug size is 20 percent of the total pore volume, and the concentration is 250 ppm.

Figure 17 is a plot of water-oil ratio versus oil recovery per ac-ft. This plot indicates that a recovery of 122 bbl of oil per ac-ft could be expected from a conventional waterflood at a WOR (water-oil ratio) of 25. At the same WOR, 199 bbl oil per ac-ft could be expected with the polymer flood. This would be an increase in oil recovery of approximately 3,111,000 bbl for the entire field. Figure 18 is a time versus production rate graph of the two flood calculations.

The total secondary recovery for the conventional waterflood at a WOR of 25 was calculated to be 4,946,000 bbl oil. The secondary recovery calculated by the method presented by Johnson (1956, p. 395) at the same WOR is 6,686,000 bbl oil. The main difference in the two methods is that the model assumes Buckley-Leverett fractional flow in which the flow is dependent upon the relative permeability curve. The Johnson method assumes piston-like displacement. With the use of an average water saturation of 26.4 percent, a gas saturation of 3.85 percent, and the relative permeability curve (Figure 11), the model started producing at a WOR of 0.99. If the oil produced prior to a WOR of 0.99 is not taken into consideration, the two methods of calculation agree within 10 percent.

The oil recovery with polymer flooding at a WOR of 25 is calculated by the model to be 8,057,000 bbl, an increase of 3,111,000 bbl over the recovery of the conventional waterflood. This calculation appears to be reasonable. A Johnson calculation for a continuous polymer slug indicates a recovery of approximately 12,921,000 bbl oil. The Johnson calculation was expected to be higher than the model calculation because of the use of a continuous viscous slug.

Economics

The economics of polymer flooding was calculated by using a net oil price of $2.1935 per bbl and a polymer price of $1.21 per lb. The operation of the polymer injection equipment is expected to cost approximately $5000 per yr. A produced water handling cost of $0.015 per bbl was used. The basic operating costs are assumed to be the same for both floods. A yearly summary of the production, expenses, and income is given in Figure 19.

The waterflood lasts 19 years and produces 5,340,310 bbl of oil. The polymer flood lasts 27 years and produces 8,812,900 bbl of oil. The additional costs or (savings) column includes the $5000 per yr cost to inject the polymer for the first 3.11 years. It also includes the difference in the produced water handling costs of the two floods. For the years 20-27, the basic operating costs are also included. The economic limit in both floods occurs at a WOR of about 33.3.

The polymer flood results in an incremental net profit of $5,071,956. The net income (before federal income tax) discounted at 12 percent is $2,563,560. The discounted annual rate of return is 141 percent.

CONCLUSIONS

(1) The application of polymer flooding in the Stewart Ranch Field is economically feasible. This analysis was based on the use of one type of polymer furnished by Dow Chemical Company. An attempt to analyze other polymers was not made.

(2) It is evident that two additional producing wells are needed to attain a good areal-sweep efficiency in the reservoir. These wells (proposed wells 23 and 24) should be drilled as soon as possible for maximum oil recovery.

(3) Additional analysis of the application of polymer flooding in this field is warranted. This analysis should include a comparison of the various polymers available for use in decreasing the mobility of the injection water. Also, the optimum slug size should be determined for individual injection wells based on the reservoir properties surrounding each injection well.

(4) The Stewart Ranch Field has been a successful waterflood project and is a potentially successful polymer-flood project.

APPENDIX

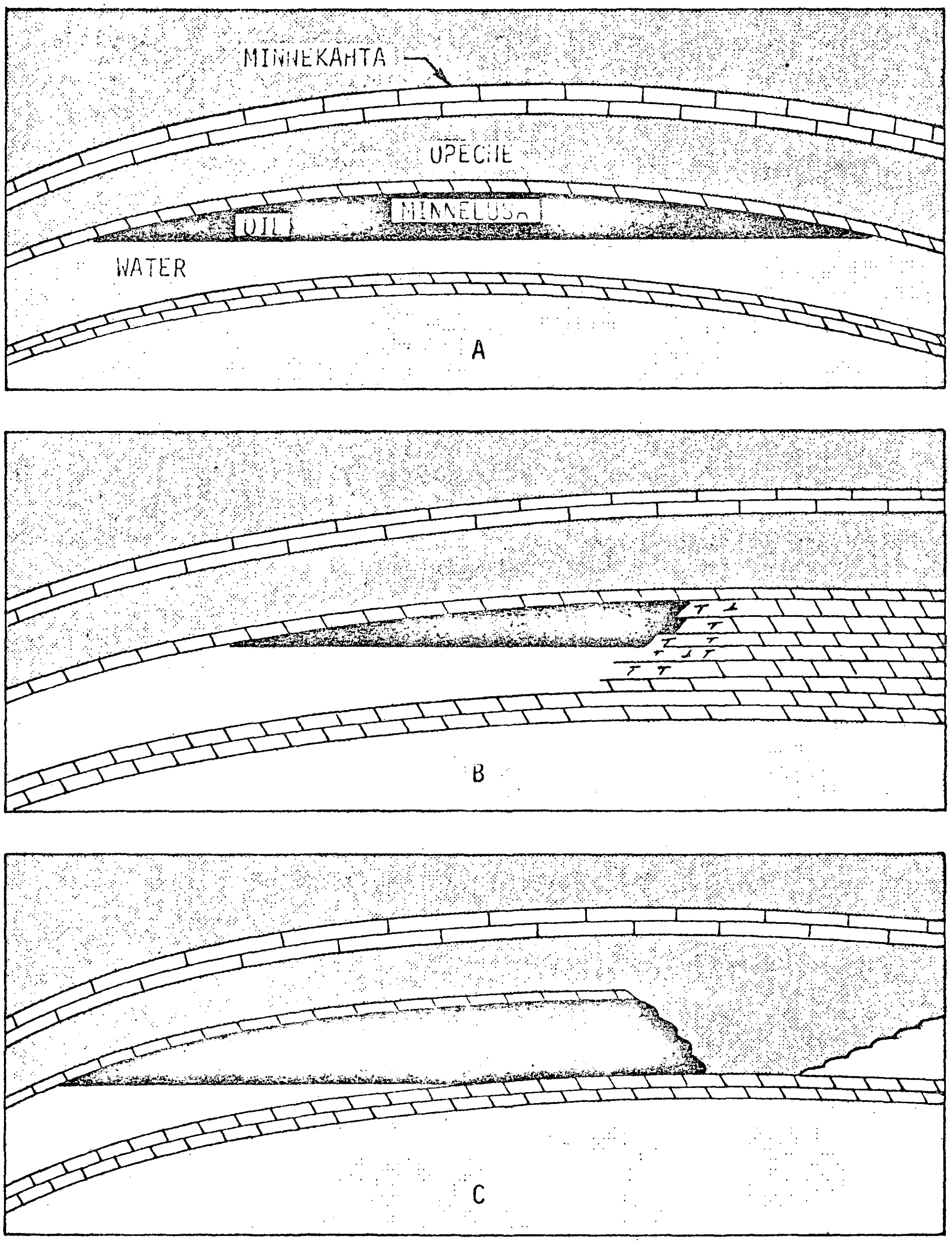
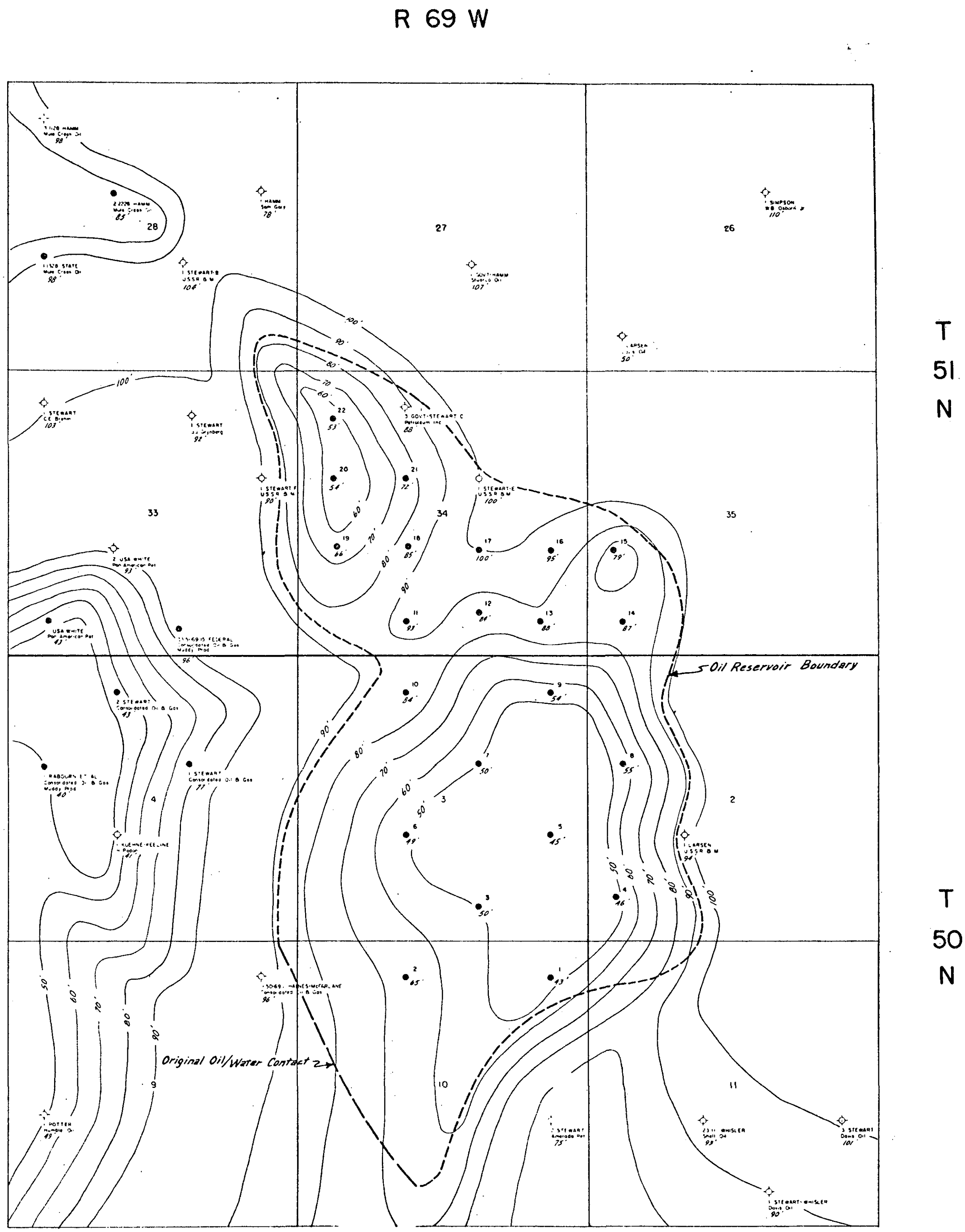


FIGURE 1
DIAGRAMMATIC CROSS SECTIONS OF
MINNELUSA TRAPS

A STRUCTURAL
B STRATIGRAPHIC (FACIES CHANGE)
C STRATIGRAPHIC (UNCONFORMITY)

From Berg (1963, p. 168)



STEWART RANCH FIELD

CAMPBELL COUNTY, WYOMING

FIGURE 2

ISOPACHOUS MAP

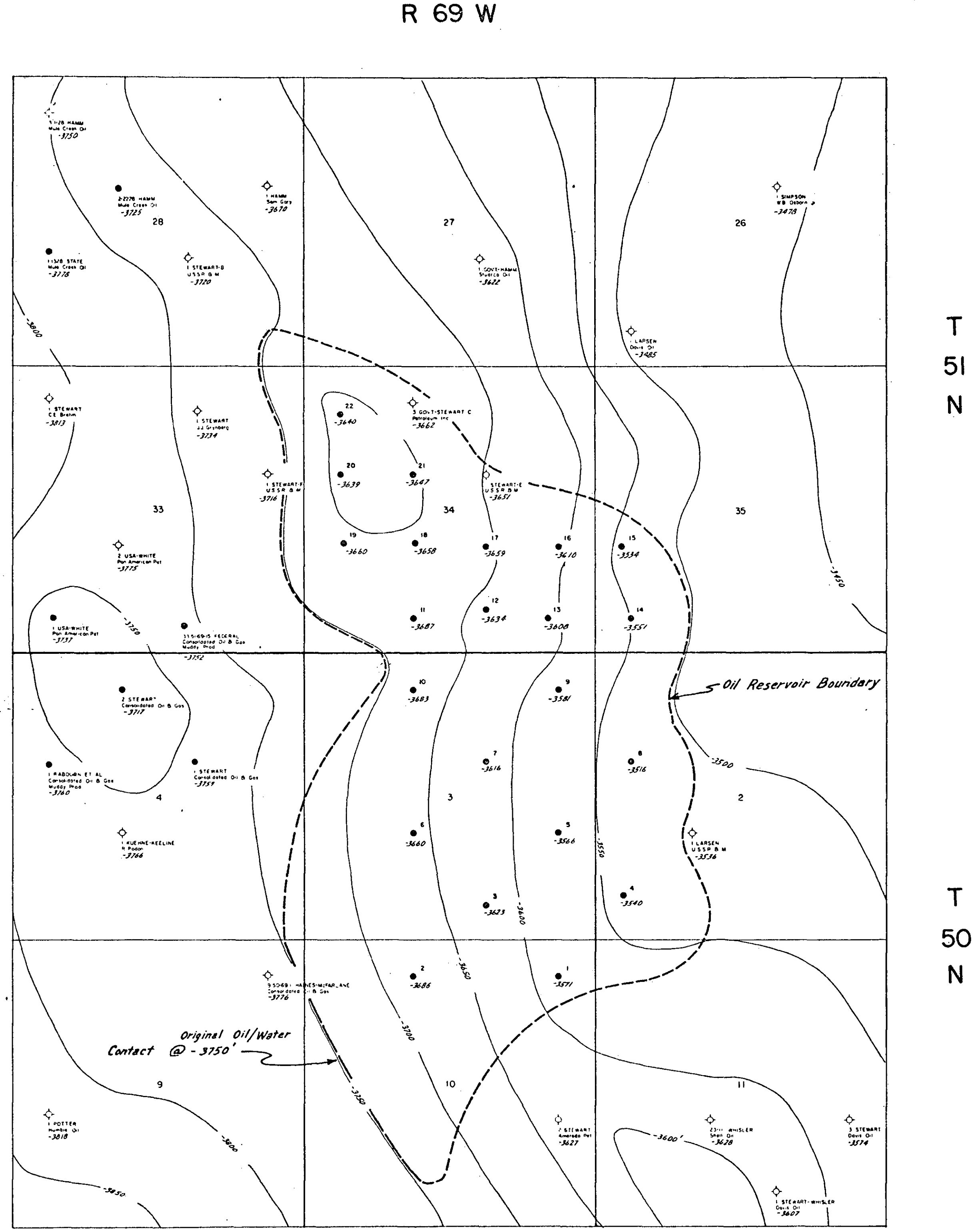
OPECHE SHALE

C. I. = 10'

0' 1000' 2000' 3000' 4000' 5000'

By : Jack Mc Cartney

Date : Jan 25, 1971



STEWART RANCH FIELD

CAMPBELL COUNTY , WYOMING

FIGURE 3

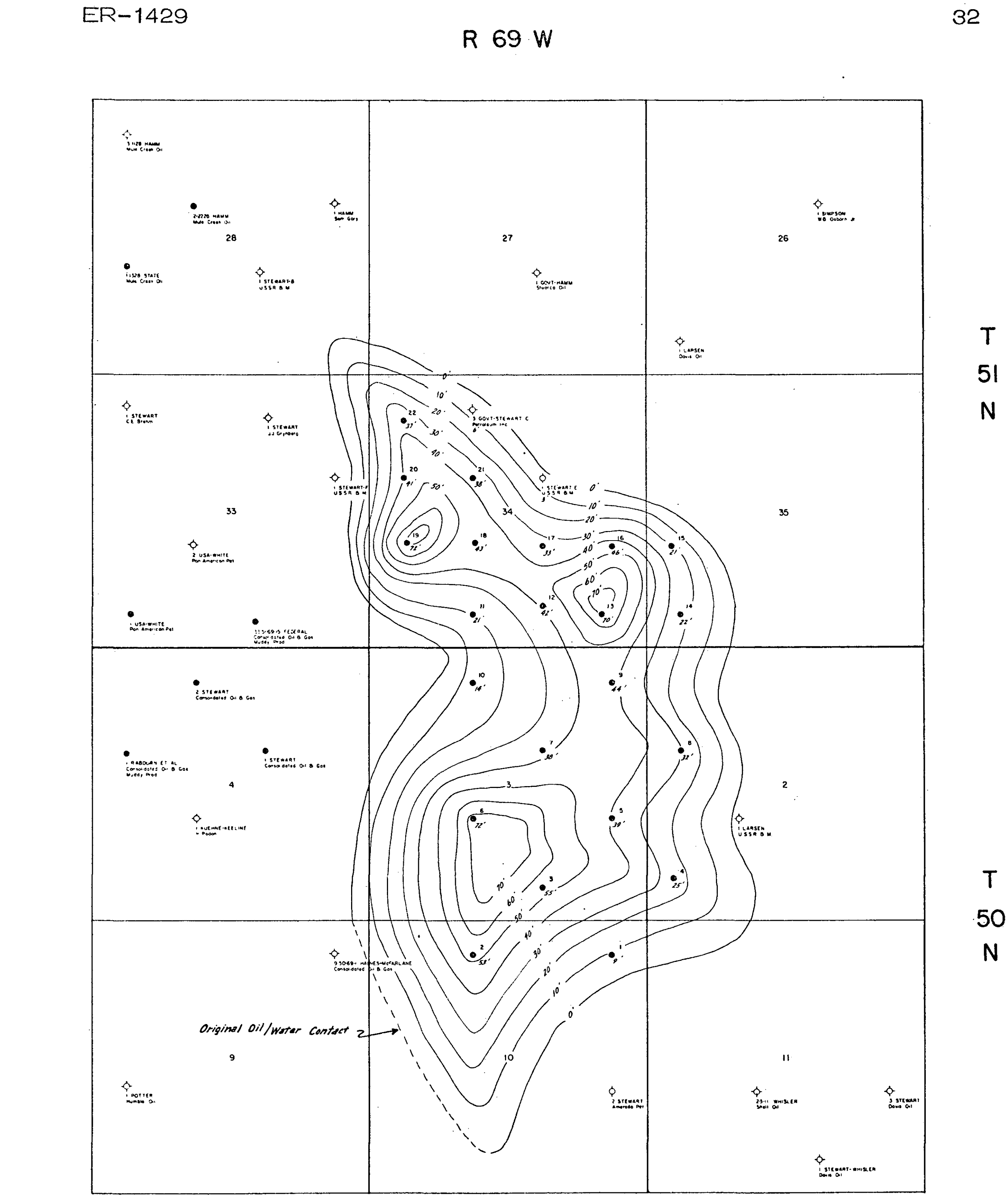
STRUCTURE MAP

TOP OF MINNELUSA FORMATION

C.I. = 50'

By : Jack Mc Cartney

Date : Jan 25, 1971



STEWART RANCH FIELD

CAMPBELL COUNTY , WYOMING

FIGURE 4

ISOPACHOUS MAP

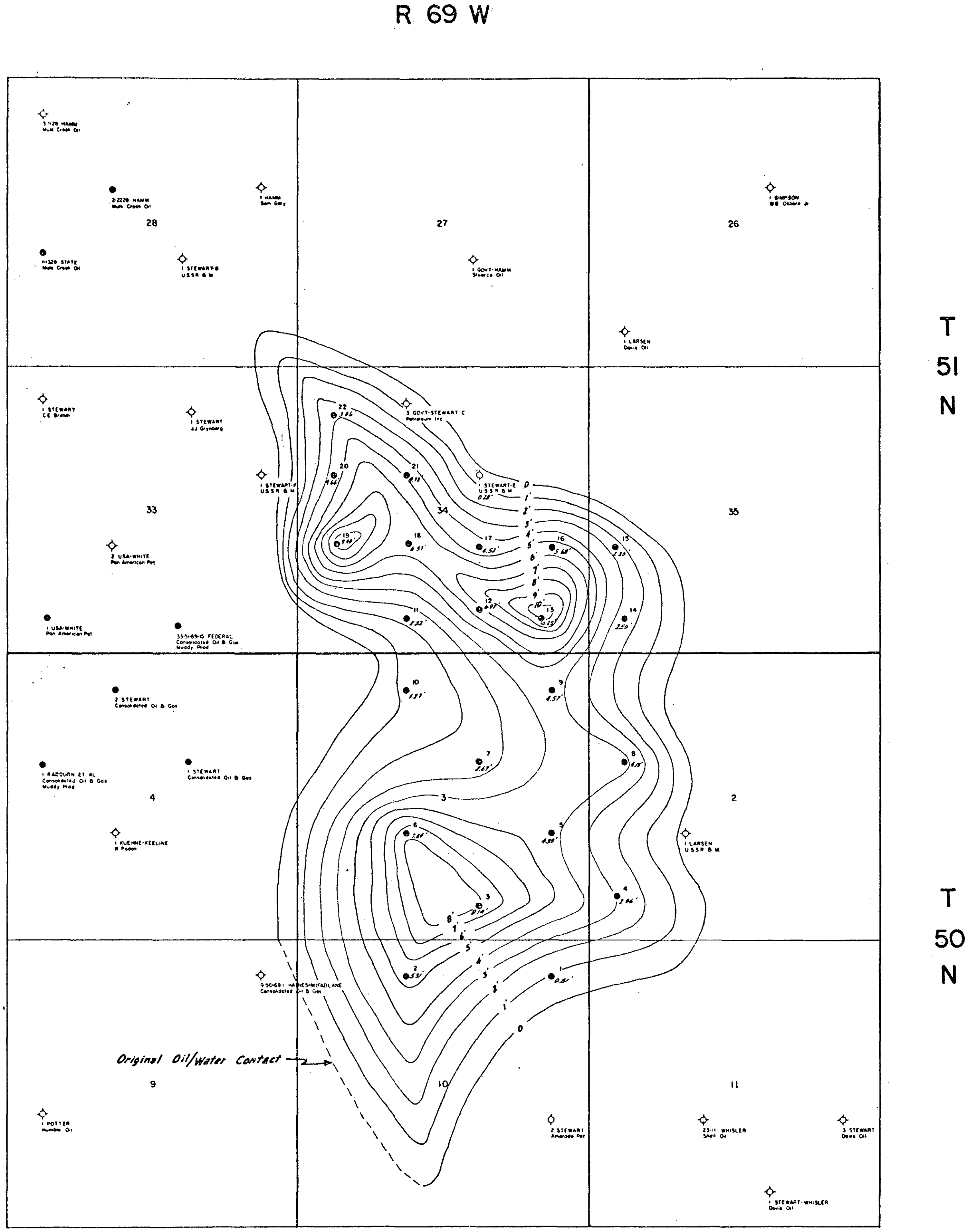
NET PAY

MINNELUSA "B" SAND

C.I. = 10'

By : Jack Mc Cartney

Date : Jan 25, 1971



STEWART RANCH FIELD

CAMPBELL COUNTY , WYOMING

FIGURE 5

ISOPACHOUS MAP

HYDROCARBON PORE VOLUME

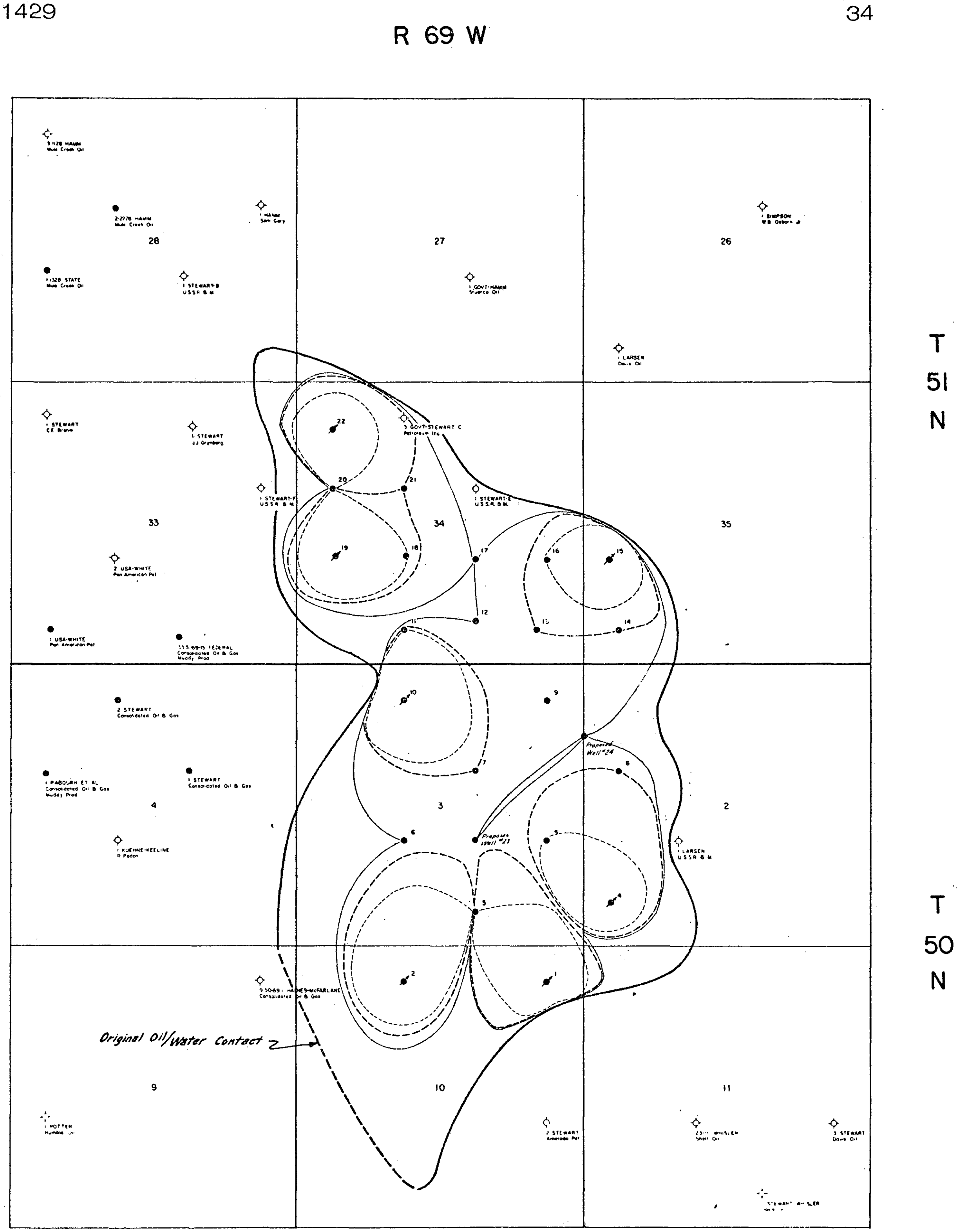
MINNELUSA "B" SAND

C.I. = 1'

0' 1000' 2000' 3000' 4000' 5000'

By : Jack Mc Cartney

Date : Jan 25, 1971



STEWART RANCH FIELD

CAMPBELL COUNTY, WYOMING

FIGURE 6

INJECTION PATTERN MAP

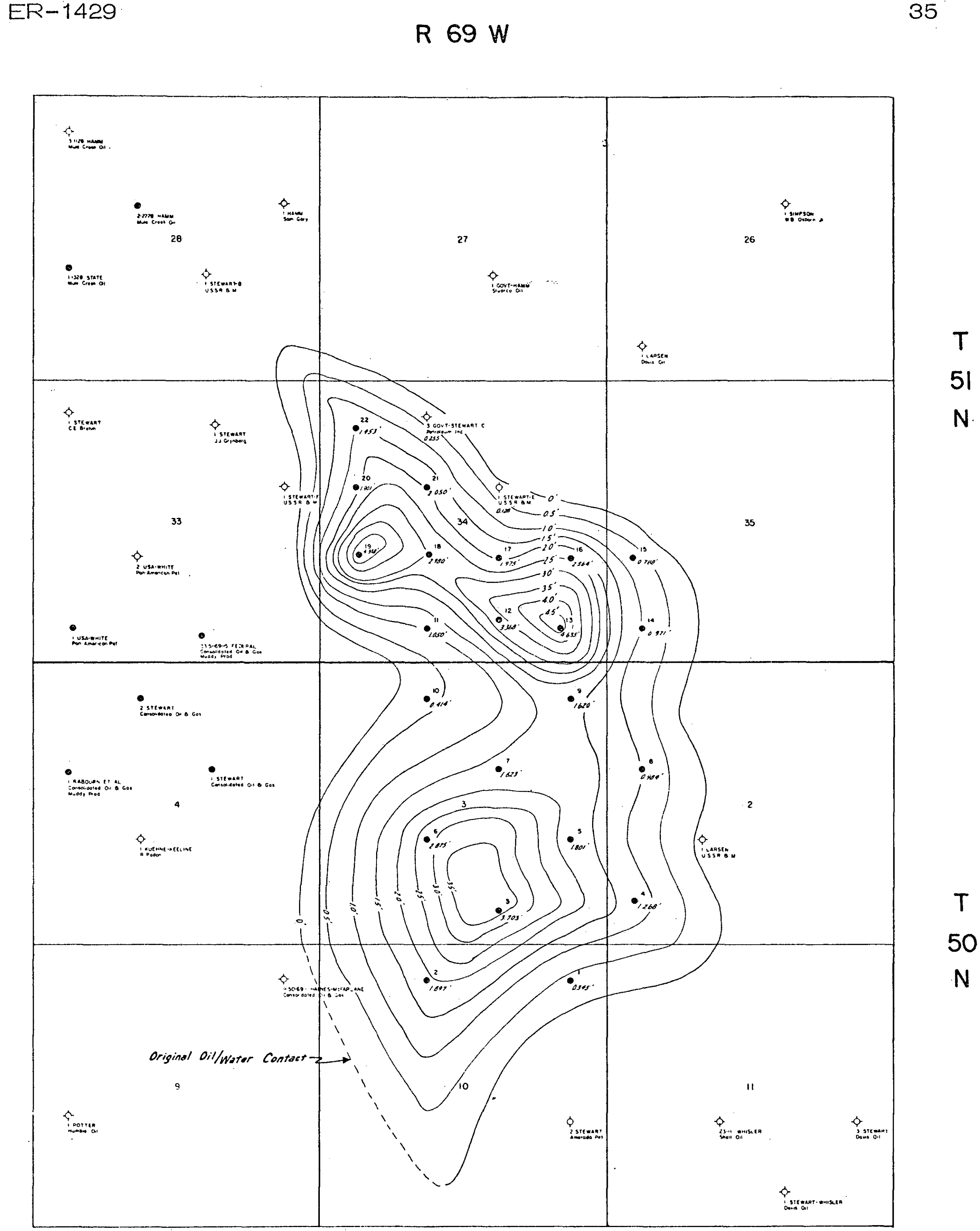
------ Phase I
------ Phase II
—— Phase III

Injection well

Area not swept by waterflood

By : Jack Mc Cartney

Date : Jan 25, 1971



STEWART RANCH FIELD

CAMPBELL COUNTY , WYOMING

FIGURE 7

ISOPACHOUS MAP

DISPLACEABLE PORE VOLUME

MINNELUSA "B" SAND

C. I. = 0.5'

By : Jack Mc Cartney

Date : Jan 25, 1971

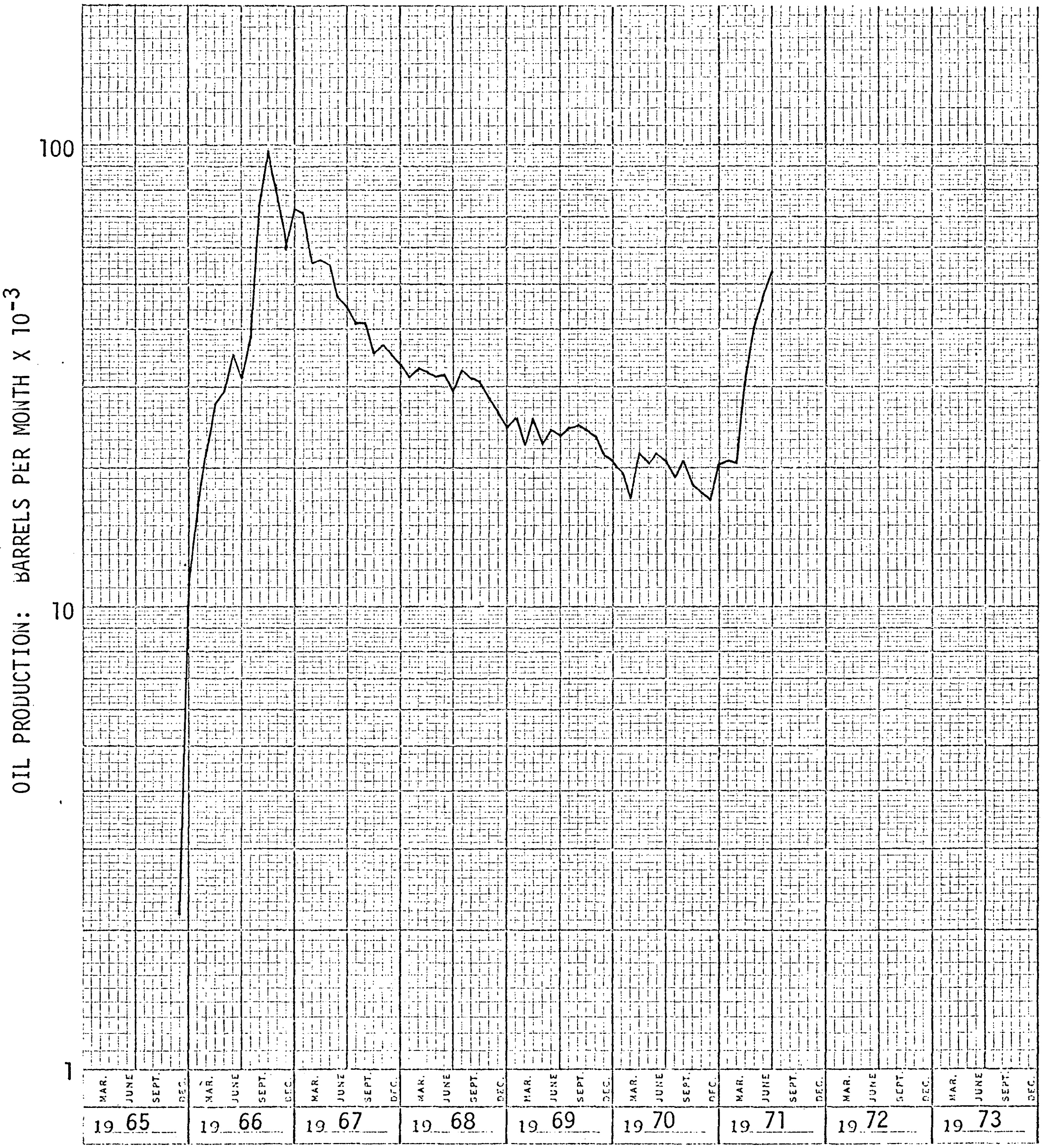


Figure 8: Oil Production History

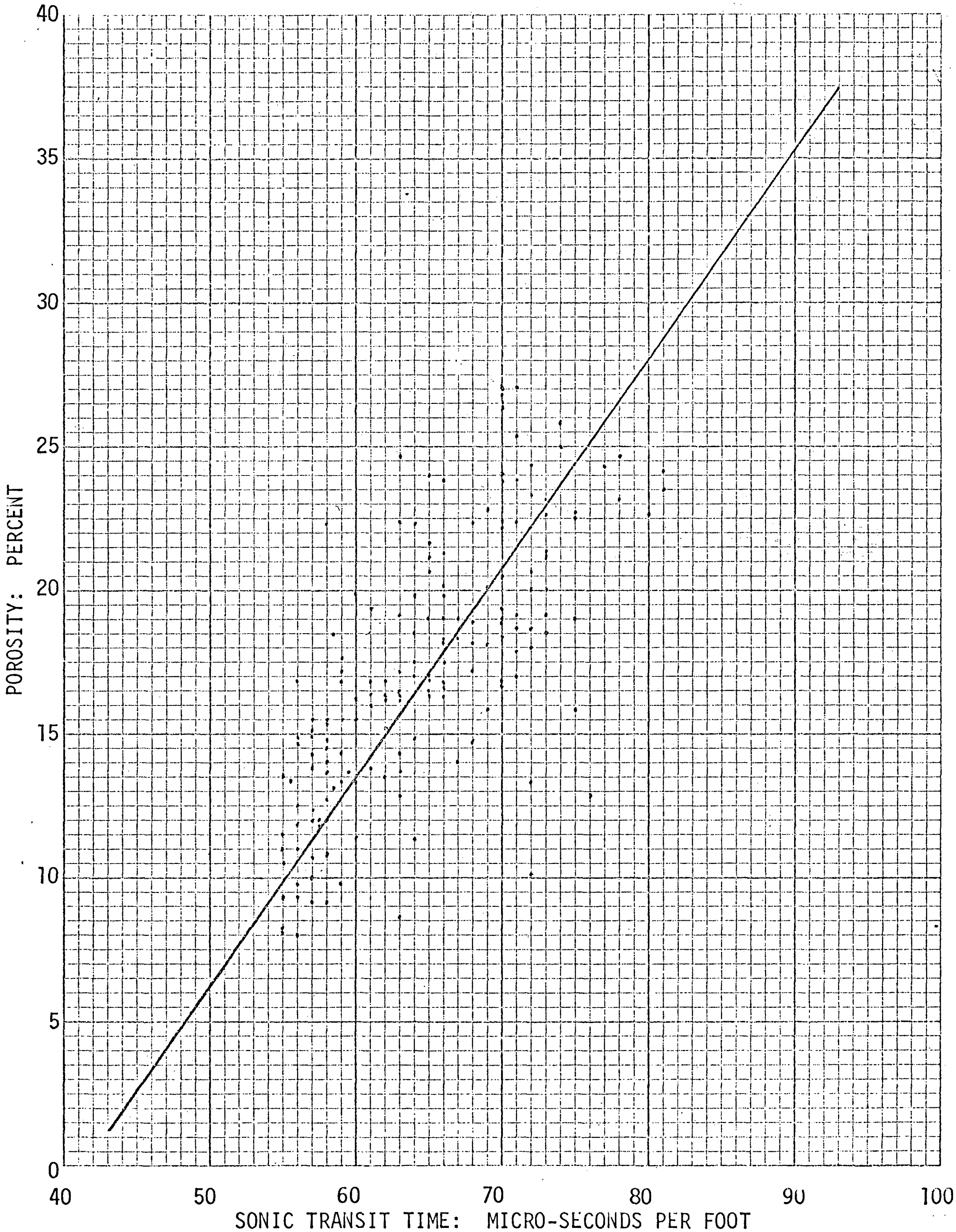


Figure 9: Sonic Travel Time - Porosity Correlation

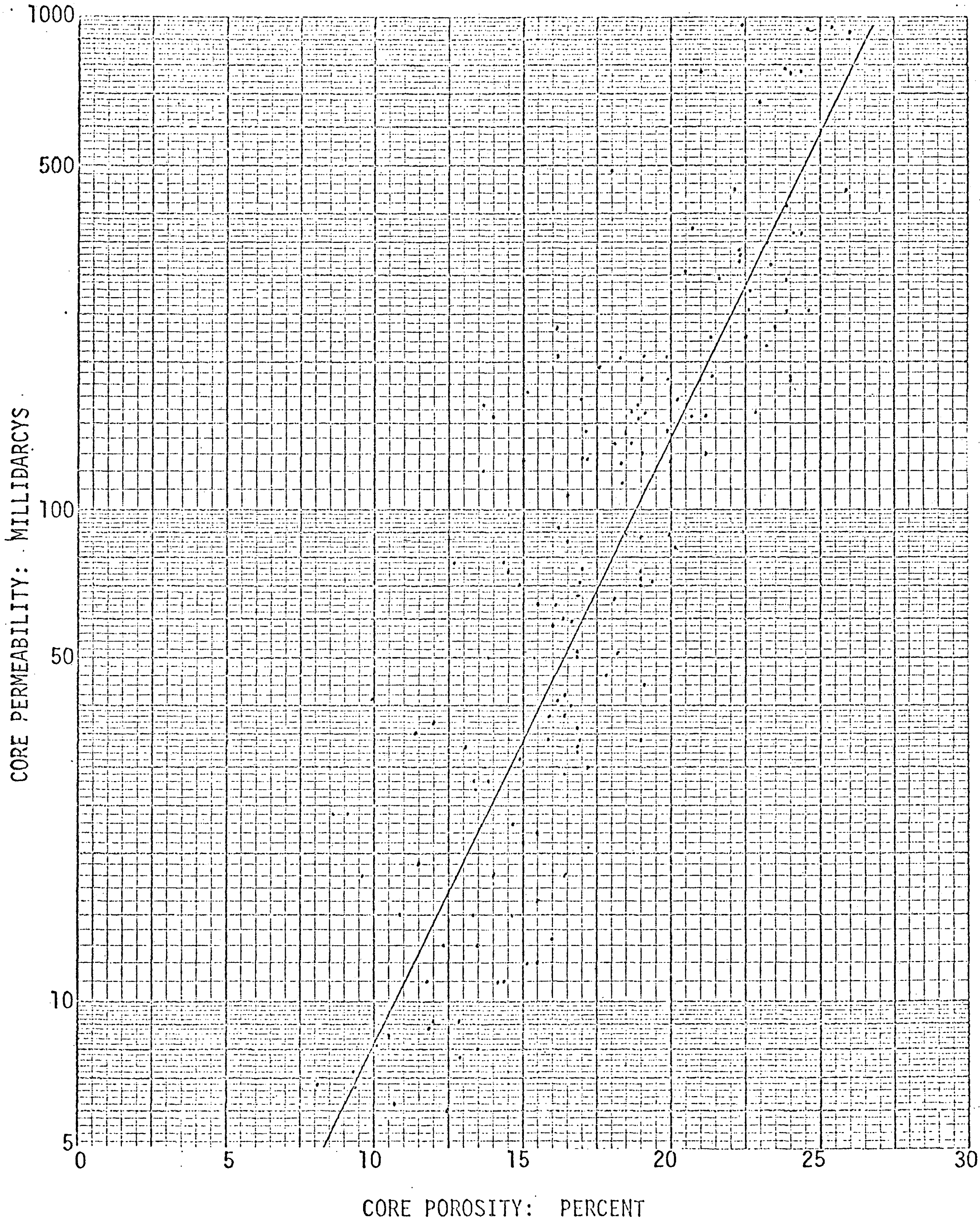


Figure 10: Core Permeability - Core Porosity Correlation

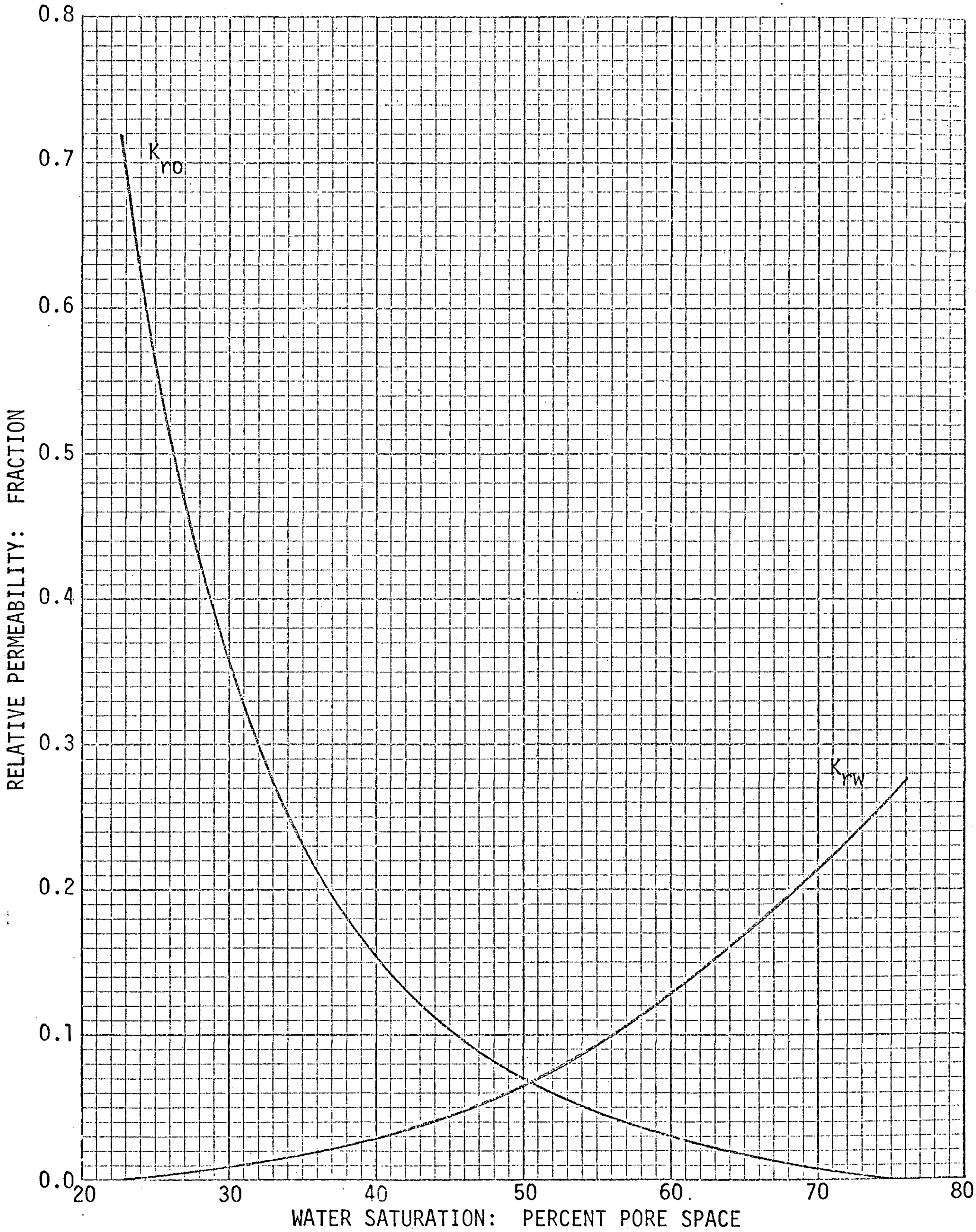


Figure 11: Relative Permeability Curves

Pressure psig	Pressure-Volume Relation @ 139 °F Relative Volume of Oil and Gas V/Vsat.	Viscosity of oil @ 139°F Centipoises	DIFFERENTIAL LIBERATION @139°F Gas/Oil Ratio Liberated Per Barrel of Residual Oil	DIFFERENTIAL LIBERATION @139°F Relative Oil Volume V/Vr
2000	0.9906	21.8		1.033
1400	0.9936	20.2		1.036
1100	0.9951	19.4		1.038
900	0.9961			1.039
800		18.6		
700	0.9971			1.040
500	0.9982	17.8		1.041
400	0.9988			1.042
300	0.9994	17.3		1.042
186	1.0000	17.0	0	1.043
183	1.0023			
181	1.0039			
175	1.0077			
160	1.0164			
143	1.0319			
125		17.2	3	1.043
123	1.0553			
105	1.0863			
88	1.1331			
72	1.1940			
58	1.2796			
52		17.7	7	1.042
44	1.3888			
34	1.5292			
22	1.9863			
14	2.4529			
8	3.2191			
0		19.3	14	1.032

Figure 12: Fluid Analysis Data

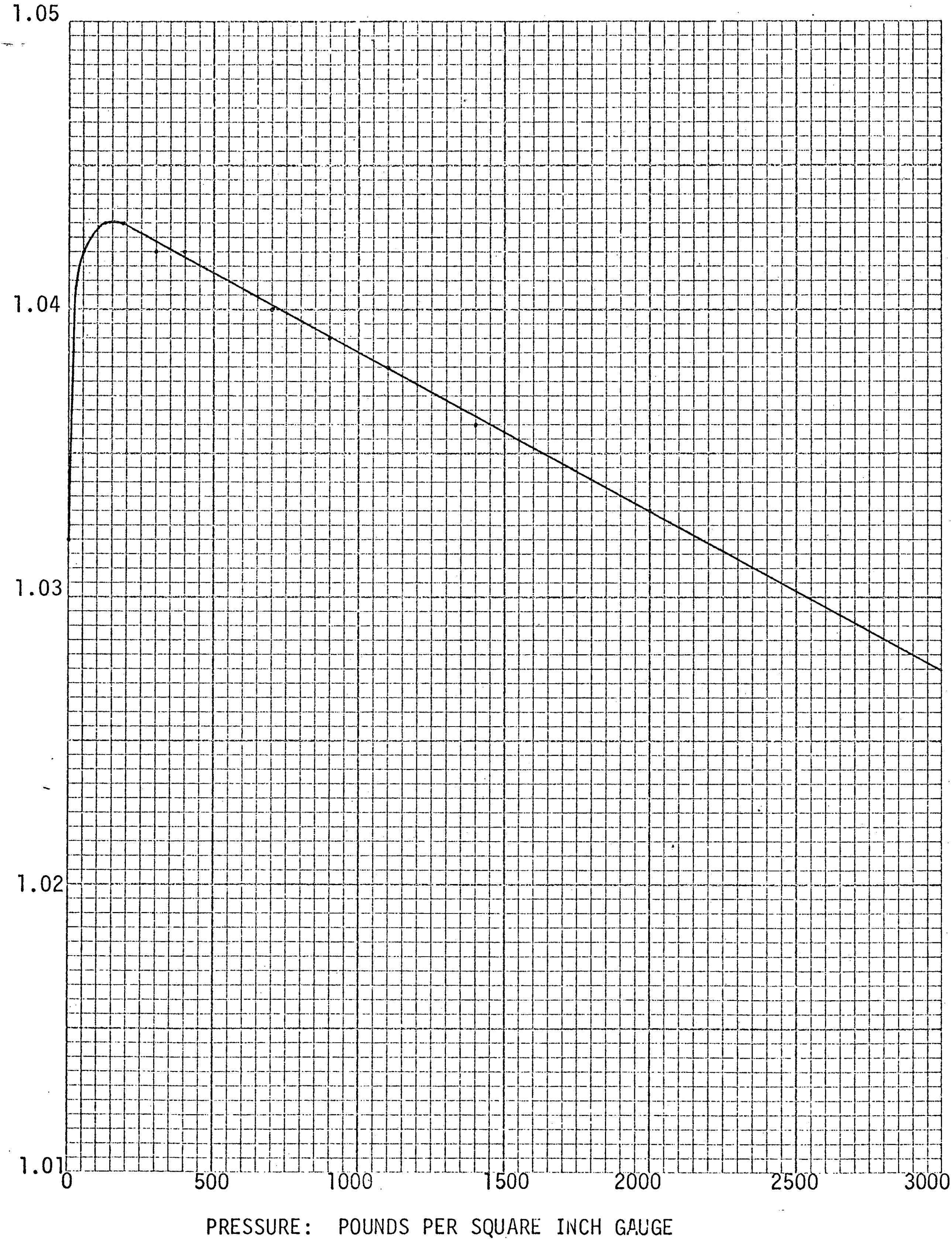


Figure 13: Oil Formation Volume Factor - Pressure Relationship

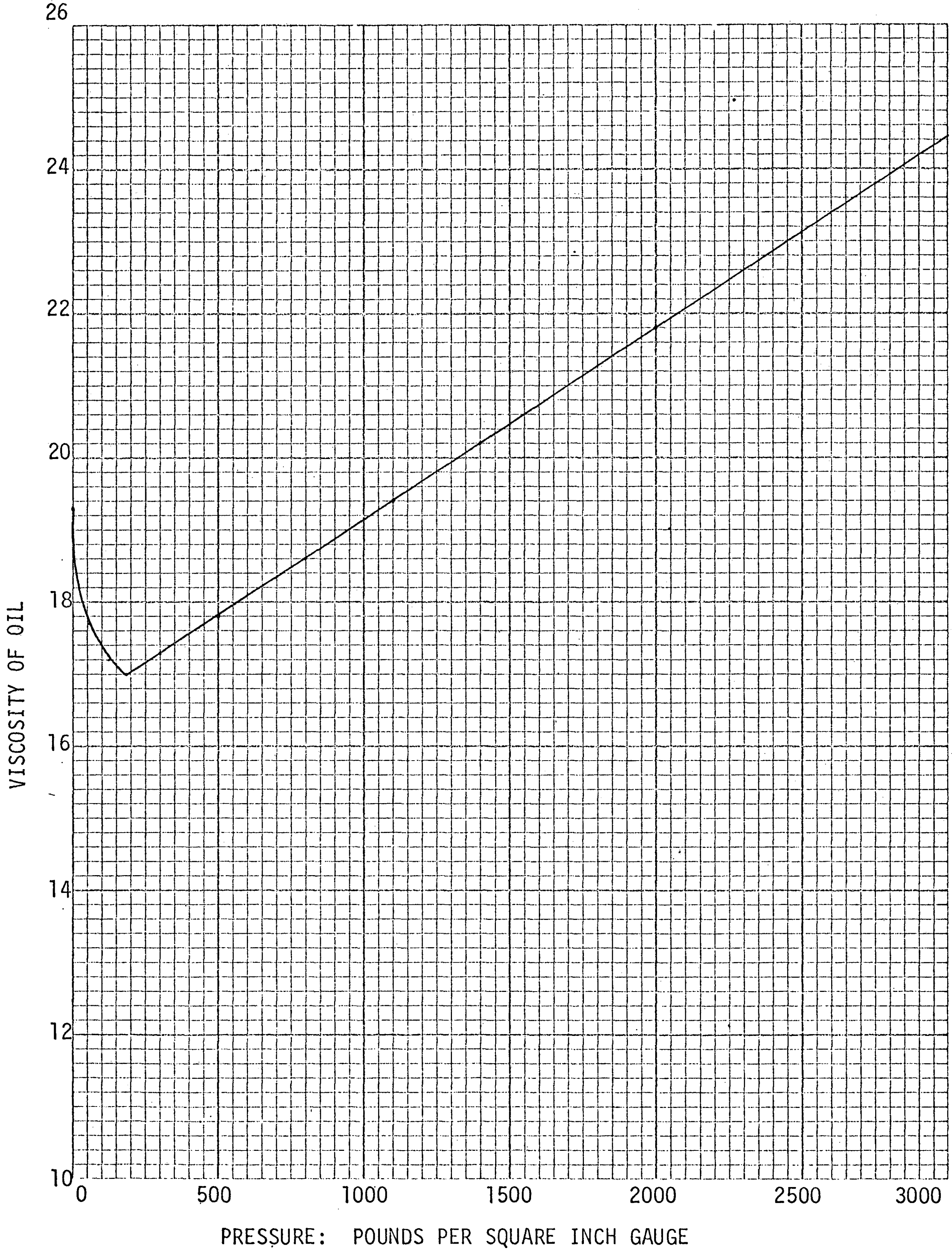


Figure 14: Viscosity of Oil - Pressure Relationship

Average Depth, ft	8100
Reservoir Volume, ac-ft	48,187
Reservoir Temperature, ^{0}F	136
Original Oil in Place, bbl	43,797,000
Pressure at Steady State Conditions, psig	2890
Oil Formation Volume Factor @ 2890 psig	1.028
Oil Viscosity @ 2890 psig, cp	24.2
Water Viscosity, cp	0.484
Mobility Ratio	17.4
Porosity, percent	16.3
Average Permeability, md	92
Permeability Variation Factor	0.625
Water Saturation, percent	26.4
Gas Saturation (for model calculation only), percent .	3.85
Areal Sweep Efficiency, percent	83.9
Injection Rate, bbl per day	9000
Polymer Resistance Factor @ 250 ppm	11
Polymer Residual Resistance Factor	3
Polymer Adsorption, lb per ac-ft	50

Layer Data For Model

Layer	Porosity (percent)	Permeability (millidarcys)	Water Sat. (percent)	Gas Sat. (percent)
1	20.7	175	26.4	3.85
2	18.2	83	26.4	3.85
3	16.3	50	26.4	3.85
4	14.5	30	26.4	3.85
5	11.8	14	26.4	3.85

Figure 15: Model Data

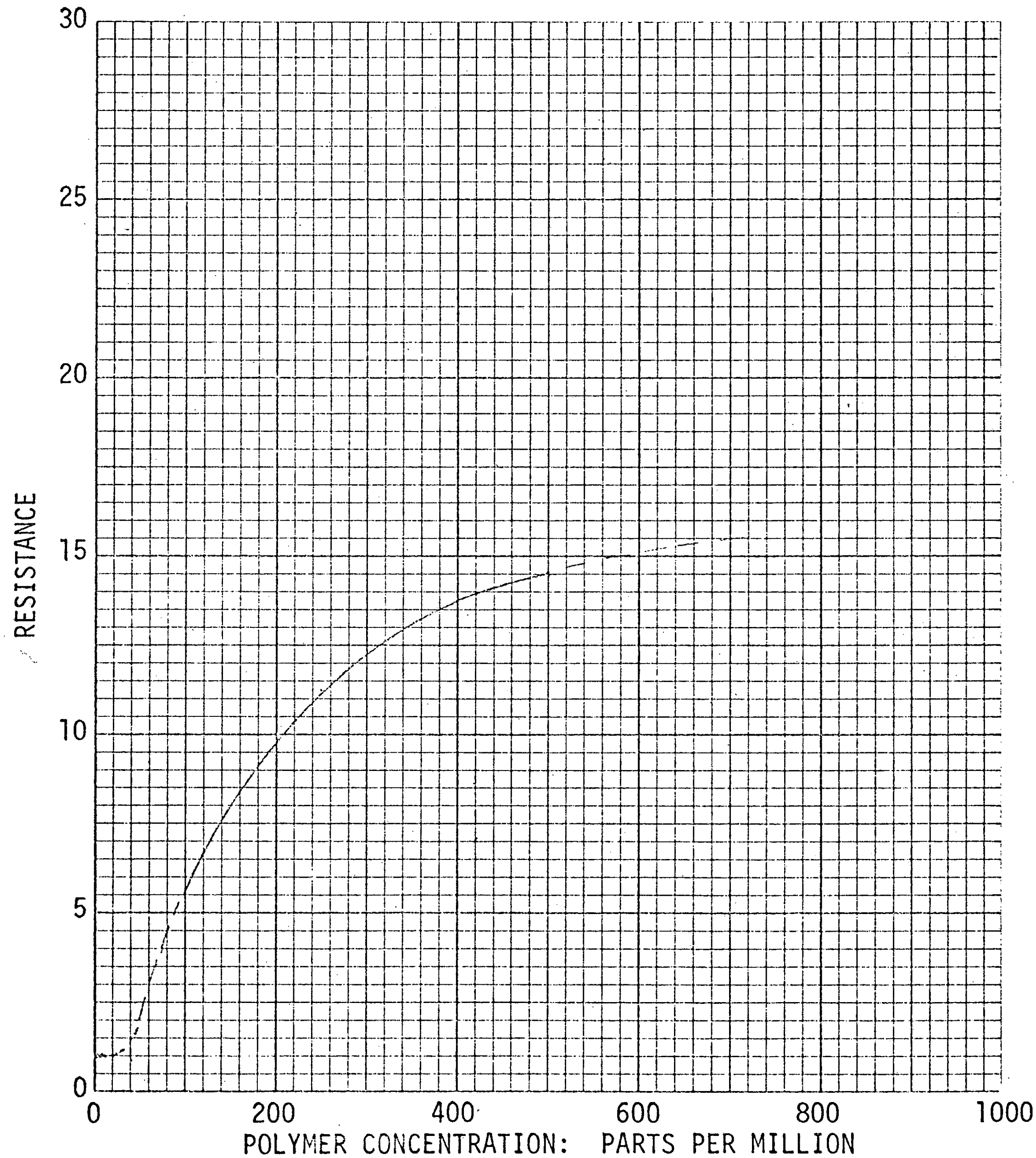


Figure 16: Resistance - Polymer Concentration Relationship

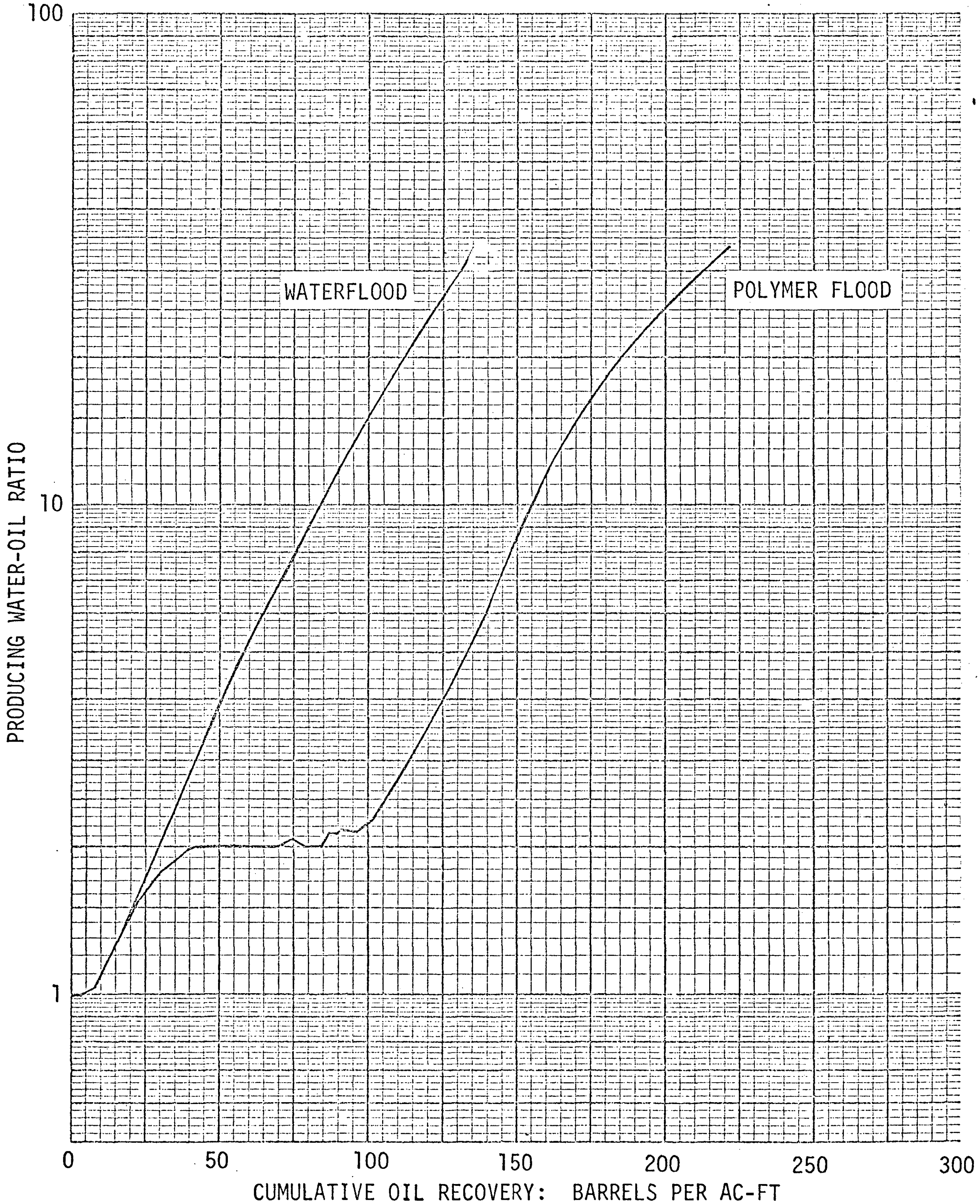


Figure 17: Water-Oil Ratio - Cumulative Oil Recovery Prediction

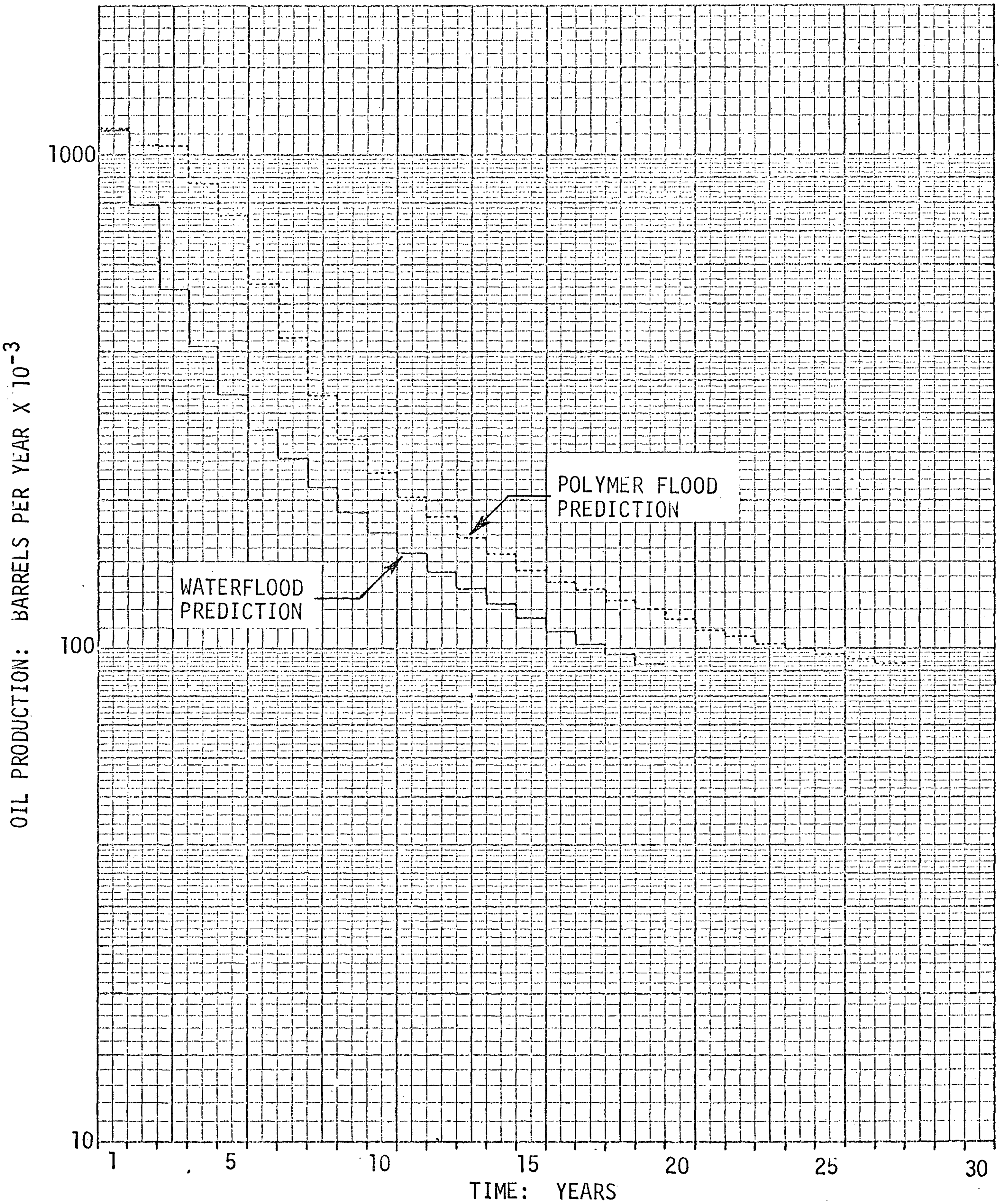


Figure 18: Polymer Flood and Waterflood Time-Rate Prediction

YEAR	CONVENTIONAL WATERFLOOD OIL PRODUCTION (BARRELS)	CONVENTIONAL WATERFLOOD WATER PRODUCTION (BARRELS)	POLYMER FLOOD OIL PROUDCTION (BARRELS)	POLYMER FLOOD WATER PRODUCTION (BARRELS)	INCREMENTAL OIL (BARRELS)	INCREMENTAL WATER (BARRELS)	NET VALUE OIL (DOLLARS)	POLYMER COSTS (DOLLARS)	ADDITIONAL COSTS OR (SAVINGS) (DOLLARS)	NET PROFIT (DOLLARS)
1	1118570	1528419	1129300	1539272	10730	10853	23536	347592	5163	-329219
2	794620	2346247	1047520	1335596	252900	-1010651	554736	347592	(10160)	217304
3	536620	2611057	1043340	2091022	506720	- 520035	1111490	347592	(2801)	766699
4	406240	2744781	869800	2266024	463560	- 478757	1016819	39737	(6609)	983691
5	327700	2825631	757440	2384704	429740	- 440927	942635		(6614)	949249
6	278580	2875724	541970	2605524	263390	- 270200	577746		(4053)	581799
7	241290	2920310	421680	2729219	180390	- 191091	395685		(2866)	398551
8	211110	2950490	324170	2828675	113060	- 121815	247997		(1827)	249824
9	189180	2972420	265420	2888884	76240	- 83536	167232		(1253)	168485
10	170980	2990620	228440	2928300	57460	- 62320	126039		(935)	126974
11	155820	3005780	202710	2954030	46890	- 51750	102853		(776)	103629
12	143050	3018550	184380	2972360	41330	- 46190	90657		(693)	91350
13	132360	3029240	168560	2988180	36200	- 41060	79405		(616)	80021
14	123260	3038340	155630	3001110	32370	- 37230	71004		(558)	71562
15	115410	3043290	143730	3013010	28320	- 30280	62120		(454)	62574
16	108780	3049920	136700	3020040	27920	- 29880	61243		(448)	61691
17	102870	3055830	130800	3025940	27930	- 29890	61264		(448)	61712
18	97420	3061280	125340	3031400	27920	- 29880	61243		(448)	61691
19	92450	3066250	120020	3038680	27570	- 27570	60475		(413)	60888
20	-	-	114800	3043900	114800	3043900	251814		185659	66155
21	-	-	109770	3048930	109770	3048930	240780		185734	55046
22	-	-	105260	3053440	105260	3053440	230888		185802	45086
23	-	-	101700	3057000	101700	3057000	223079		185855	37224
24	-	-	99200	3059500	99200	3059500	217595		185893	31702
25	-	-	97120	3061580	97120	3061590	213033		185923	27110
26	-	-	95110	3063590	95110	3063590	208624		185954	22670
27			92990	3065710	92990	3065710	203974		185986	17988
TOTAL	5346310	54134179	8812900	75095620	3466590	20961441	7603966	1082513	1449997	5071456

Figure 19: Economic Summary of Polymer Flood

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