

A PROCEDURE FOR THE EVALUATION, DESIGN, AND
IMPLEMENTATION OF A POLYMER FLOOD

By

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ABSTRACT

A procedure for the feasibility evaluation and implementation of a polymer flood is developed on the basis of published laboratory, mathematical, and field data. The procedure includes data collection, data evaluation, analogy to cases of successful polymer floods, polymer flood design, and field implementation. A hypothetical example is provided to illustrate the proposed procedure.

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INTRODUCTION

Among enhanced oil recovery processes, polymer flooding has been most widely applied to improve oil recovery in the last decade. Oil recovery by waterflooding has been poor in reservoirs with a high vertical permeability variation. After waterflooding, up to 80 percent of the oil may remain in the reservoirs. Polymer solutions have been successfully applied to recover additional oil from naturally depleted or waterflooded reservoirs because of their superior mobility control properties¹⁻⁹ over and above that of water in porous media.

A literature survey indicated that there has not been a concrete procedure or a guideline established for carrying out a feasibility appraisal and engineering design of a polymer flood. It was decided to make this the topic of this report.

This report is concerned primarily with the evaluation and implementation of a polymer flood as a secondary recovery process. However, some published papers involving the use of polymer solutions in tertiary oil recovery are also included in the Bibliography.¹²⁻²⁰

A FEASIBILITY EVALUTATION PROCEDURE OF A POLYMER FLOOD

The importance of properly evaluating a reservoir before designing a polymer flood can not be overemphasized. An inadequate evaluation may lead to misjudgement in the polymer flood design, resulting in economically unsuccessful operations. The following feasibility evaluation procedure is proposed to provide an adequate evaluation and design of a polymer flood.

Data Collection

The reservoir and operation data should be gathered as completely as possible. These data include:

1. Reservoir Geometry: Reservoir structure, boundary, closure, thickness, stratification, depth, productive area and bulk volume.
2. Reservoir Rock and Fluids Properties:
Reservoir pressure, temperature, porosity, permeability, lithology, the fluid P-V-T data, and initial oil, gas and water saturations. If available, relative permeability and capillary pressure data should also be obtained.
3. Production Records: Cumulative production and production rates of oil, gas and water.
4. Well Records: Number of wells producing, abandoned, or shut in; well configuration; well pressure history; well logs; mode of production - flowing, pumping, gas lifting; and well completion records.

5. Equipment Records: Flowlines; well head equipment ; valves; chokes; treating, storage and transmission equipment.

Data Evaluation

Once the available data have been collected, they should be fully analyzed and evaluated to obtain the following information:

1. Estimate of the original oil and gas in place using volumetric and material balance methods.
2. The primary recovery mechanism of the reservoir.
3. Current gas, oil and water saturations and the present amount of oil remaining in place.
4. The average porosity, permeability, and permeability variation (if any); the formation water salinity; the formation type, and mineral contents.

Analogy to Cases of Successful Polymer Floods

Polymer flooding, like all other enhanced oil recovery methods, is not applicable to all reservoir types and conditions. For a quick preliminary evaluation, it is advisable to compare the above evaluated reservoir data with those of the reservoirs which have been successfully flooded by the use of polymer solutions.

Jewett and Schurz¹ provided statistics of successful field cases of polymer floods. They defined successful as economically profitable from the polymer flood operations. Ranges of reservoir conditions associated with these successful field polymer floods are as follows:

1. The mobility ratio ranges from 0.1 to 42. Mobility ratio is defined here as the brine mobility at residual oil saturation to the oil mobility at irreducible water saturation. The upper limit of the oil viscosity is 126 cp.
2. The mobile oil saturation ranges from 0.15 to 0.46. The mobile oil saturation is defined as the difference between the oil saturations at the start and termination of the polymer flood.
3. The maximum initial water saturation reported is 47 percent.
4. Reservoir permeability ranges from 50 md to 2300 md.
5. The permeability variation described by Dykstra-Parsons²¹ ranges from 0.28 to 0.8.
6. Projects started at, or near, the end of the primary depletion have had the highest percentage of success. Tertiary projects have been less successful.
7. Both sandstone and limestone reservoirs have been successful polymer flood candidates. Grossly vugular limestones should be avoided.
8. The maximum reservoir water salinity is 14 percent (140,000ppm).
9. Porosity ranges from 0.10 to 0.39.
10. The maximum reservoir temperature reported is 229°F.

It need be emphasized that the above information is meant for general guidelines only. Reservoirs with some of the conditions not

lying within the ranges need not be discarded at first glance, since the decision to design a polymer flood for a reservoir would depend on further evaluation of the effectiveness of available polymer types in recovering oil from the reservoir.

Design of a Polymer Flood

When the candidate reservoir analogy with successful floods indicates a good possibility of a successful polymer flood, it is proposed that the following procedure be followed to complete the feasibility evaluation for a polymer flood.

New Data Requirement

In addition to the above information, new data are required to complete a polymer flood study. These data are concerned with: Water Supply, Polymer Properties, and Displacement Process.

Adequate supply of desirable water is a must for a successful polymer flood. The following data on the water supply are needed:

1. Amount of water available,
2. Chemical and solid-content analysis on the water,
3. Compatibility of the water with the reservoir conditions and polymer selected,
4. Compliance with governmental regulations, and
5. Cost of the water.

A discussion on polymer properties and selection is presented in Appendix 1. Following is a list of the required data on the polymer properties:

1. Types of polymers commercially available,
2. Compatibility with injection water,
3. Compatibility with reservoir water and temperature,

4. Polymer retention in the reservoir,
5. Mobility control in the displacement process,
6. Required concentration for effective mobility control in the reservoir, and
7. Injection rate limit compatible with completion perforations without excessive shear degradation.

When the above data have been collected, data on waterflood and polymer flood displacement processes are needed. If cores are available, the following waterflood displacement data should be obtained:

1. Residual oil saturation,
2. Oil and water production history,
3. Water injection history, and
4. Pressure history.

For the polymer flood process, the following data can be obtained from core floods:

1. Residual oil saturation,
2. Oil and water production history for different sizes of polymer slug,
3. Water injection history,
4. Pressure history, and
5. Polymer retention for each slug size considered.

When cores are not available, the residual oil saturation to waterflooding may be estimated from well log analysis using shallow- and deep-investigating logs, porosity and mud filtrate resistivity. Residual oil saturation to both waterflooding and polymer flooding may also be obtained from similar flooding operations in adjacent leases.

Selection of a Polymer Flood Process

Polymer floods are usually slug processes where the polymer solution injection is followed by a driving water. Jewett and Schurz¹ presented the ranges of several factors that affect a polymer flood oil recovery performance.

As they pointed out, these criteria can be used only for rough screening of reservoirs being considered for polymer flooding. For the selection of a polymer flood process, additional design factors should include:

1. The slug size to be injected,
2. The type of polymer,
3. The concentration of the polymer,
4. Whether to inject water ahead of the polymer to fill existing void or gas space, and if so, to what extent?
5. The volume of drive water to be injected,
6. The pattern type and size, and
7. At what depletion stage to start injection.

One can use one or a combination of several methods to evaluate the design factors. These are (1) Correlations from existing data; (2) Laboratory experiments; and (3) Computer Modeling.

Correlations are based on published performance data on commercially successful polymer floods. One such correlation is presented by Agnew.² The use of correlations should be viewed with some skepticism since the reservoir and field conditions on which they are based may not necessarily be similar to those of the reservoir under consideration. They should be used where a more reliable design evaluation is not justified by economic

reasons or data availability.

Laboratory experiments simulating field conditions of a projected flood are performed and the relative effects of several displacement-process factors are evaluated to select the optimum flooding process. The problem is that of scaling model laboratory experiments to large-scale field conditions.

Most or all of the design factors mentioned above can be evaluated by a suitably designed computer program. Several models are available. Wang and Caudle²² present a streamline model based on steady-state flow. Patton, Coats, and Colgrove²³ used a layered streamline mathematical model to predict polymer flood performance. Graue²⁴ predicted polymer flood results with a linear, layered reservoir model. Jewett and Schurz¹ present a computer program based on two-dimensional, two-phase, noncommunicating-layer mathematical model. Uzoigwe, Scanlon, and Jewett²⁶ present a model using a programmed slug to predict polymer flood performance. Bondor, Hirasaki, and Tam²⁵ developed a three-phase, three-dimensional, four-component, compressible mathematical simulator that allows the simulation of a variety of complex situations. This simulator takes into account the presence of a gas cap or desaturated zone due to gravity drainage in a dipping reservoir, the presence of an aquifer, irregular well spacing and reservoir boundaries, multizones, reservoir heterogeneities, and well performance that is limited by state proration, injectivity, and productivity. The simulator also incorporates the adsorption of polymer, the dispersion of the polymer slug and the effect of non-Newtonian flow behavior on the injectivity of polymer. The equations used in developing this model are presented in Appendix 2.

Pattern Selection

The choice between a peripheral and repeating-pattern flood depends on existing well pattern, and the requirement of a minimum of new wells to provide oil productivity and maximize oil recovery with a minimum production of injected fluids. The pattern should take advantage of known reservoir uniformities, e.g. regional permeability differences, directional permeability, formation fractures, dips, etc., and be compatible with flooding operations in adjacent leases.

Once the pattern of a polymer flood is selected, the injectivity of polymer solution should be evaluated:

1. Determine the maximum bottom-hole, and thus the maximum injection-well pressure that will not fracture the reservoir,
2. Calculate the initial water or polymer solution injection rate from the appropriate equation for the chosen pattern presented by Deppe.³⁰ For a five-spot, the initial injection rate is given by:

$$i_{\text{initial}} = (0.001538h \lambda_o \Delta p) / [\log(d/r_w) - 0.249] \quad (1)$$

where i_{initial} = initial injection rate, res. B/D

h = net pay thickness, ft.

λ_o = mobility of the reservoir fluid, md/cp

Δp = pressure differential between injection and producing wells, psig

d = distance between injection and producing wells, ft.

r_w = well radius, ft.

To estimate the injectivity as the flood progresses, this initial injection rate is used as the base injection rate in the relative injectivity relation³⁰ for a five-spot pattern:

$$I_r = \log(r_e/r_w) / [\log(r_e/r_f) + 1/M \log(r_f/r_w)] \quad (2)$$

where I_r = Relative Injectivity
 r_e = Well drainage radius for the pattern, ft.
 r_w = Well radius, ft.
 r_f = Radius of the displacing fluid front from the injection well, ft.
 M = Mobility ratio of the flood.

Recovery and Economic Evaluation

The recovery performances for a waterflood and polymer floods using varying slug sizes (10, 20, 30, and 40 percent are recommended) may be calculated using correlations,^{2,21,34} laboratory experimental data or computer modeling. Details are described in the Illustrative Example. An expense-income analysis based on (1) the oil and polymer price at the projected start of the flooding operation, (2) the predicted production rate, (3) cumulative oil recovery and water injected; and (4) operating costs, is made for all the displacement processes. The most profitable one is chosen for field implementation.

IMPLEMENTATION OF A POLYMER FLOOD

When details of the polymer flood are specified, it remains for the engineer to provide the equipment for mixing and injecting the polymer solution; prepare the injection and production wells for the operations; and provide the equipment for treating produced fluids.

Equipment for Mixing and Injecting Polymer Solution

A polymer mixing and injecting plant should be designed such that options for chemical treatment and filtration of the water and polymer solution at different stages are possible.²⁷ Figure 1 shows a diagram of a typical mixing and injecting plant.

An adequate and reliable source of water supply such as from a lake, river, pond, well or nearby city water plant must have been ascertained before the design and implementation of the flood. A treating plant to remove oxygen and/or bacteria and/or solids is installed to improve the quality of the mixing water.

The polymer is mixed in a skid-mounted variable-feed mixer usually rented from a service company like Dow Chemical Company. The mixer capacity is calculated based on the injectivity and polymer slug size requirement. The mixer should have a capacity 25 percent higher than is called for to account for idle time. The mixing-skid should be provided with the option to treat the polymer solution with bactericides and oxygen scavengers.

The polymer solution is pumped from the mixing-skid to holding tanks. The holding tanks are needed to provide flexibility in testing the effect of mixing time, different chemicals and temperature changes. These tanks should be made of a nonferrous material, like fiber glass, to minimize chemical degradation. Floating lids and paddles should be provided to

prevent contact with the atmosphere and to keep the polymer solution stirred before use. The holding tanks should be able to hold one-quarter daily polymer requirement.

The polymer solution is then passed through filters, usually diatomaceous earth filters, to remove unhydrated polymers and solids. The micron-rating of the filter depends on the maximum rate of filtering compatible with polymer stability.²⁷

From the storage tanks, the polymer solution is pumped to the injection wells through a distribution manifold. The pump rate and pressure are based on the designed injection rate and pressure. The pumps are usually positive-displacement types to minimize excessive shear of the polymer. Plastic pipes should be used for all interconnecting piping of the polymer mixing section. The piping from the injection pumps could be internally coated with plastic to insure chemical stability of the polymer.

Injection and Producing Well Completions

The injection and producing wells should be tested thoroughly for leaks, poor cement bonding, and wellbore damages. If wells have developed leaks and communication behind casing, workover should be carried out to remedy the problems. If the wells show wellbore damages, acidizing and other adequate stimulation techniques should be employed to improve the injectivity and productivity of the wells. Also tubings, packers, and other bottom-hole equipments should be in good working condition.

Equipment for Treating Produced Fluids

To treat produced fluids during primary depletion, production facilities including production and test headers and separators, emulsion treaters, storage tanks, transmission pumps and pipelines are installed. For a

polymer flood, in addition to the above, equipment to demulsify the produced polymer water should be provided so that it can be reinjected into the reservoir.

AN ILLUSTRATIVE EXAMPLE

An illustrative example is provided to show the major aspects of the feasibility evaluation procedure. This hypothetical example used data obtained either from field or by assumptions.

Data Collection

The data used in this example are shown in Tables 1 and 2 and Figures 2 and 13. The reservoir data and production data are from McCartney²⁸; the polymer and well completion data are assumed.

Data Evaluation

The original oil in place is estimated by volumetric and material balance methods. The isopach map of the net pay thickness is shown in Figure 2. Bulk reservoir volume can be calculated by planimetry of the area inside the isopach lines and using the trapezoidal formula.³⁵ The oil in place can be calculated by multiplying the bulk volume by the average porosity and oil saturation. The original oil in place was calculated to be 43,797,000 STB (stock tank barrels).

The original oil in place can also be estimated from a material-balance calculation. Since the reservoir was originally undersaturated (see Table 2 and Figure 7), the original oil in place can be calculated by the following formula³³:

$$N = (N_p / C_e \Delta P) (B_o / B_{oi}) + (W_p B_p - W_e) / (C_e \Delta P B_{oi}) \quad (3)$$

where N = Original oil in place, STB

N_p = Cumulative oil production, STB

ΔP = Pressure drop, psig

B_o = Current oil formation-volume factor, RB(reservoir barrels)/STB

B_{oi} = Initial oil formation-volume factor, RB/STB

W_p = Water production, STB

B_w = Water formation-volume factor, RB/STB

W_e = Water influx, RB

C_e = Effective fluid compressibility, psi^{-1} .

C_e is evaluated from the relation³⁰:

$$C_e = (C_o S_{oi} + C_w S_{wi} + C_f) / S_{oi}$$

where S_{oi} = Initial oil saturation,

S_{wi} = Initial water saturation

C_f = Reservoir rock compressibility, psi^{-1} .

$C_w = (B_{wi} - B_{wb}) / (B_{wb} \Delta P_{ib})$, psi^{-1} .

$C_o = (B_{oi} - B_{ob}) / (B_{oi} \Delta P_{ib})$, psi^{-1} .

where B_{wi} = Initial water formation-volume factor, RB/STB

B_{wb} = Water formation-volume factor at the bubble-point, RB/STB

B_{ob} = Oil formation-volume factor at the bubble-point, RB/STB

ΔP_{ib} = Pressure drop from initial to bubble-point, psig.

The reported cumulative production prior to the pressure survey of November, 1970 (Figure 3), was 1,989,246 STB oil and 531,373 STB water. If the water influx is neglected, the original oil in place is calculated to be 70,480,911 STB. A water influx of 983,672 RB would cause the material-balance calculated oil in place to equal the volumetric calculated oil in place.

No gas production had been reported till November, 1970. The primary recovery mechanisms of the reservoir were rock and fluid expansions, and water influx. The remaining oil in place at the projected start of the polymer flood can be estimated from the oil production history, Figure 3, by decline curve analysis.³² In Figure 3, the upward trend of

oil production rate from December, 1970, is due to water injection into the reservoir; so this portion of the plot will not be considered in our analysis.

Suppose a polymer flood was projected to start November, 1972, twenty-four months after the time of the pressure survey. Figure 5 (curved line), shows the rate-time production decline curve plotted on log-log paper. Shifting the time axis by 9.0 the curved plot transforms to a straight line whose equation is given by:

$$q = 449,289 (t + 9.0)^{-0.8038} \quad (4)$$

The oil production rate by November, 1972, is calculated to be 13,004 bbl/day. By integrating equation (2), with respect to time, the cumulative production, N_p , at any time is given by:

$$N_p = 2,290,749 (t + 9.0)^{0.1962} \quad (5)$$

The cumulative production by November, 1972, is calculated to be 2,237,492 STB. The remaining oil in place by November, 1972, is calculated to be 41,559,508 STB.

To estimate the pressure at the start of the polymer flood, equation (3) is rearranged, neglecting the water influx and water production terms, to obtain:

$$\log N_p = \log NC_e + \log [\Delta P / (1 + C_o \Delta P)] \quad (6)$$

When N_p is plotted against $\Delta P / (1 + C_o \Delta P)$ on log-log paper, a straight line of slope 1.0 is obtained as shown in Figure 6. With water influx a curve deviating to the right of this line will be obtained. If the cumulative oil productions for various pressure drops are known, the actual trend of this curve is ascertained, and the pressure drop corresponding to any known cumulative oil production in the future can be estimated. For the case under consideration, only two sets of cumulative

oil and water production are available: one, before any production at all, and the other, at the time of the pressure survey. The pressure corresponding to the estimated cumulative oil production of 2,237,492 STB by November, 1972, could be roughly estimated by drawing a straight line through these two known points to represent the production trend with water influx. Based in this approximation, the pressure by November, 1972, is estimated to be 761 psig.

Analogy to Cases of Successful Polymer Floods

With an encouraging estimated remaining oil in place, the candidate reservoir conditions are compared to the ranges of reservoir conditions reportedly associated with commercially successful floods.¹

Reservoir Parameter	Candidate Reservoir Value	Reported Range
Initial water saturation, %	0.264	0.47*
Permeability, md	92	50-2300
Permeability Variation	0.625	0.28-0.8
Formation Water Salinity, %	10	14*
Oil Viscosity, cp	24.4	126*
Mobile Oil Saturation, %	0.43	0.15-0.46
Mobility ratio	13.65	0.1-42
Depletion Stage	Near end of primary	Near or at end of primary
Formation type	Sandstone	Sandstone, limestone
Porosity	0.163	0.10-0.0.39

To continue the evaluation, new data as listed on pages 5 through 7 are needed. The water analysis, polymer properties and displacement-process data are usually obtained by contracting to a service company like Core Laboratory, Incorporated.

* maximum value

If cores are not available, the residual oil saturation to waterflooding may be estimated from the following empirical relationship developed by Archie:³⁰

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

$$S_{or} = 1 - (FR_{mf}/R_{xo})^{1/n}$$

S_{or} = Residual oil saturation in the flushed zone

F = Formation resistivity factor

R_{mf} = Mud filtrate resistivity, from mud filtrate resistivity measured at the surface and corrected to formation temperature, ohm-m

R_{xo} = Flushed zone resistivity, obtained from the Micro-laterolog or Proximity log, ohm-m

ϕ = Porosity, fractional

n = Saturation exponent (=2 for sandstone),

m = Cementation exponent, is obtained from the Archie³⁰ relation:

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

where S_w = Water saturation, fractional

R_w = Formation water resistivity, ohm-m

R_t = Total formation resistivity, ohm-m.

The cementation exponent may be determined from the slope of log R_t plotted against log R_w for a constant water saturation, usually for $S_w = 1.0$. The residual oil saturation to waterflooding may be assumed applicable to polymer flooding.²³

Selection of a Polymer Flood Process

The various design factors that affect a polymer flood as listed on page 7 can be evaluated by a layered model using correlations for areal coverage³⁴ or by a three dimensional-computer model.²⁵

An example polymer flood design calculation is presented for a layered system.

Since the advantage of a polymer flood over waterflooding is the improvement in areal and vertical coverage, the values for these parameters need be evaluated to estimate the extent of improvement that may be expected. This evaluation is based on the existing well pattern, on the assumption that the relative permeability characteristics for oil and water at initial water saturation and residual oil saturation are the same for polymer and water and that the polymer, for example, Polymer 4 in Figure 12, has a resistance factor of 11.0.

The mobility ratio for the waterflood, from Figure 4, is $(0.276/0.484) / (0.72/17.3) = 13.7$. The mobility ratio for a continuous injection of polymer is $13.7/11.0 = 1.25$

For a vertical permeability variation of 0.625, Figure 16, and a water-oil ratio of 25, the fractional vertical coverage²¹ is 0.663 for waterflooding and 0.913 for the continuous polymer slug injection. Polymer slug injection between a minimum size equal to the amount adsorbed in the reservoir and a continuous injection, indicate a possible maximum increase in vertical coverage by waterflooding from 0 to 34.7 percent and a maximum increase in areal coverage from 0 to 19.3 percent. As these factors are independent of each other, the design value can be obtained only with the layered or three-dimensional model. But the magnitude of improvement indicates a desirability of the additional evaluation.

The procedure for the calculation for the layered system in a pattern is as follows:

1. Divide the reservoir into layers following the guidelines provided by Craig³⁷ on the minimum number of layers. The layers may vary

as to absolute permeability, porosity, thickness and fluid saturations. Each layer is divided into ten equal-volume concentric rings.

2. Obtain the water-oil relative permeability curves for each layer.

The relative permeability curves govern the flow in accordance with the Buckley-Leverett³⁰ fractional flow theory and Darcy radial-flow equation. The water and oil banks are assumed to be radial until water breakthrough in the manner described by Deppe.³¹ The areal-sweep efficiency after water breakthrough follows the model data of Caudle and Witte,²⁹ in which the sweep efficiency is a function of mobility ratio and displaceable pore volumes injected.

3. With the injection of a small volume amount of fluid into the system, each layer will accept a portion of the injected volume based on the ratio of the conductivity. A conductivity based on the fluid saturation and distribution, flow geometry, and both absolute and relative permeability may be used.
4. In a given layer, the injected volume enters the first segment. Fillup occurs until the injected volume equals the mobile gas volume, if any. After fillup has occurred, the injected liquid invades 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. This liquid flows to 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.
5. All layers in the system are treated in the same manner as des-

cribed above. After the injection of each small volume, the produced fluids in each layer are summed to give the total oil and water production for that volume step. The calculation continues for a predesignated number of volume steps or until the water-oil ratio reaches a specified economic limit.

6. The above discussion pertains to a conventional waterflood. For a polymer flood, the calculation must incorporate the resistance, the residual resistance, and adsorption properties of the polymer solution. For the resistance to flow of the polymer solution, the water viscosity is multiplied by the laboratory-determined resistance factor. This effect lowers the mobility ratio in proportion to the resistance factor.
7. 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 followup water by a factor equal to the laboratory-determined residual resistance factor for the reservoir rock.
8. Adsorption should also be accounted for in the calculation procedure. As the polymer enters a segment, instantaneous adsorption occurs leaving a denuded fluid of equal volume with properties identical to those of the injected 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.

The data in Figures 2 through 13 and Tables 1 and 2 were obtained

by McCartney²⁸ from a layered model in the Stewart Ranch Field, Wyoming (Figure 2). The plots of water-oil ratio versus cumulative recovery (Figure 9), and the oil production rate versus time (Figure 10), were obtained by the previously described calculation procedure. An optimum slug size of 20 percent of the total pore volume was calculated for the Stewart Ranch field.

CONCLUSION

Based on published laboratory, mathematical and field test data on polymer flooding, a procedure has been developed for the feasibility evaluation and engineering design of a polymer flood. While there is a host of possible variations which can be placed upon the proposed procedure, the proposed procedure should provide the field engineer a step by step approach to complete a feasibility evaluation and engineering design of a polymer flood.

APPENDIX 1Polymer Properties

A polymer is a very large molecule made of thousands of repeating blocks called monomers. The long chains of monomers in the polymer molecules may be linear, branched, or crosslinked, with molecular weights in the millions. Because of their large sizes and surface areas, polymer molecules can undergo enormous changes in dimensions from a straightened to a folded or coiled form. This unique property makes polymers effective as mobility control agents in porous media.

In polymer flooding, two types of polymers are most often used: partially-hydrolyzed polyacrylamides and polyssacharide biopolymers.

Polyacrylamides are obtained by chemically combining some 50,000 or more of the amide monomers formed by carbon, oxygen, nitrogen, and hydrogen. Some of the amide groups are changed by hydrolysis to carboxylate groups to form partially-hydrolyzed polyacrylamides. Both groups are highly polar, which gives the polymer a high affinity for water but not for oil. These groups have a strong attraction to sandstone and limestone surfaces.

Polyssacharide polymers are the remains of the protective coating of the organism *Xanthomonas campestris*, grown commercially by a fermentation process. The three different saccharide monomers making up the basic polymer structure are mannose, glucose, and glucuronic acid. The polymer has a molecular weight of 2 million or more.

The main advantage of a polymer solution over water as a displacing

phase in porous media is its higher resistance or reduced mobility. The mobility control effectiveness of a polymer solution depends on the polymer concentration, polymer molecular weight, and the ion content of the solvent water. It also depends on the physical properties of the rock and the chemical nature of its surface.

Figure 4 shows the effect of different polymer solution properties on the polymer relative mobilities for different rock types. The relative mobility of a flowing phase in a porous rock at a certain saturation is defined as the ratio of its relative permeability at that saturation to its effective viscosity. Compositions of the polymers considered are given in Table 4.¹³ The permeability and porosity for the various cores were approximately equal. Many interesting points can be observed in Figure 4:¹³

1. High polymer concentrations result in lower polymer relative mobilities as indicated by the curves of Solutions 1 and 2.
2. The effect of the properties of a rock on polymer mobility is demonstrated by the curves of Solutions 2 and 3. Solution 2 which has a higher concentration than Solution 3 would be expected to have a lower mobility, but the reverse is observed. This can only be explained by more mechanical entrapment and/or adsorption in the Berea core than in the Pennsylvanian core.
3. Curves for Solutions 1 and 5 indicate that polymers with a higher molecular weight have lower mobilities than those with lower molecular weight in the same core.
4. From Solutions 4 and 5 it can be deduced that the presence

of a dissolved salt decreases the mobility-control effectiveness of a polymer solution.

The principal advantage of the reduced mobility of a polymer solution is a better volumetric sweep which results from a more favorable mobility ratio of the displacing phase to the displaced phase. A better volumetric sweep results in increased oil recover.

The main disadvantage of polymers is that they can be rendered inefficient by either chemical, bacterial or shear degradation. Degradation of a polymer is the breaking up of its long-chain molecules. Polyacrylamides and polysaccharide biopolymers are effected differently by degradation. Polyacrylamides are adversely affected by shear. Polysaccharides plug formations and are susceptible to bacterial attack.

The procedure for evaluating polymers is as follows:

1. Obtain commercially available polymers.
2. Obtain the flow characteristics of the various polymers in the candidate reservoir cores. The pertinent characteristics are the resistance factor, and the residual resistance factor, and adsorption rates at various concentrations (e.g. 0.1 to 100ft/day). The frontal velocity of a fluid flowing at a rate q ft³/day through an area A ft² of a core of porosity is given by q/A ft/day. The resistance factor 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 factor is defined as 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 residual resistance are of importance in the recovery of oil from a reservoir. An increase in resistance results in a decrease in the mobility ratio and an increase in oil recovery.

APPENDIX 2

The polymer flood simulator can be expressed by the following equations:²⁵

$$\nabla \cdot [\lambda_w b_w (\nabla p_w - \rho_w g \nabla D)] + \tilde{q}_w = \partial / \partial t (\phi b_w s_w) - (\phi / \bar{c}) \partial Q_{ads} / \partial t \quad (1)$$

$$\nabla \cdot [\lambda_o b_o (\nabla p_o - \rho_o g \nabla D)] + \tilde{q}_o = \partial / \partial t (\phi b_o s_o) \quad (2)$$

$$\nabla \cdot [\lambda_o b_o R_s (\nabla p_o - \rho_o g \nabla D)] + [\lambda_g b_g (p_g - \rho_g g \nabla D)] + \tilde{q}_g = \partial / \partial t (\phi b_o R_s s_o + \phi b_g s_g) \quad (3)$$

$$\nabla \cdot [\lambda_p b_w (\nabla p_w - \rho_w g \nabla D)] + \tilde{q}_p = \partial / \partial t (\phi b_w s_p) + (\phi / \bar{c}) \partial Q_{ads} / \partial t \quad (4)$$

where, $s_w + s_o + s_g + s_p = 1$. The polymer and the water comprise two components of the aqueous phase existing in the reservoir. Equations 1 and 4 express the conservation of each component separately, with the conversion of polymer solution into water due to polymer adsorption on rock.

The oil-water and oil-gas capillary pressure relationships are used in Eqs. 1 through 4 to obtain a single equation for the oil pressure, P_o . The pressure equation is then solved and the saturations obtained explicitly from the above equations.

Nomenclature

b	=	reciprocal of formation volume factor, STB/res. bbl.
c	=	polymer concentration, ppm
\bar{c}	=	polymer concentration, $\mu\text{gm}/\text{bbl}$
g	=	$(1/144) \text{ lb}_f \text{ sq ft}/\text{lb}_m - \text{sq. in}$
\bar{q}	=	source term, (STB or Mcf) /D/ (Unit volume)
Q_{ads}	=	mass of adsorped polymer, $\mu\text{g}/\text{bbl}$ of pore volume.
D	=	gravity head from datum, gm/cc
λ	=	mobility, md/cp
∇	=	gradient operator
R_s	=	solution gas ratio, Mcf/STB
$\nabla \cdot$	=	divergence operator
ϕ	=	porosity
S	=	saturation

Subscript

o	=	oil
w	=	water
g	=	gas
p	=	polymer
aq	=	aqueous

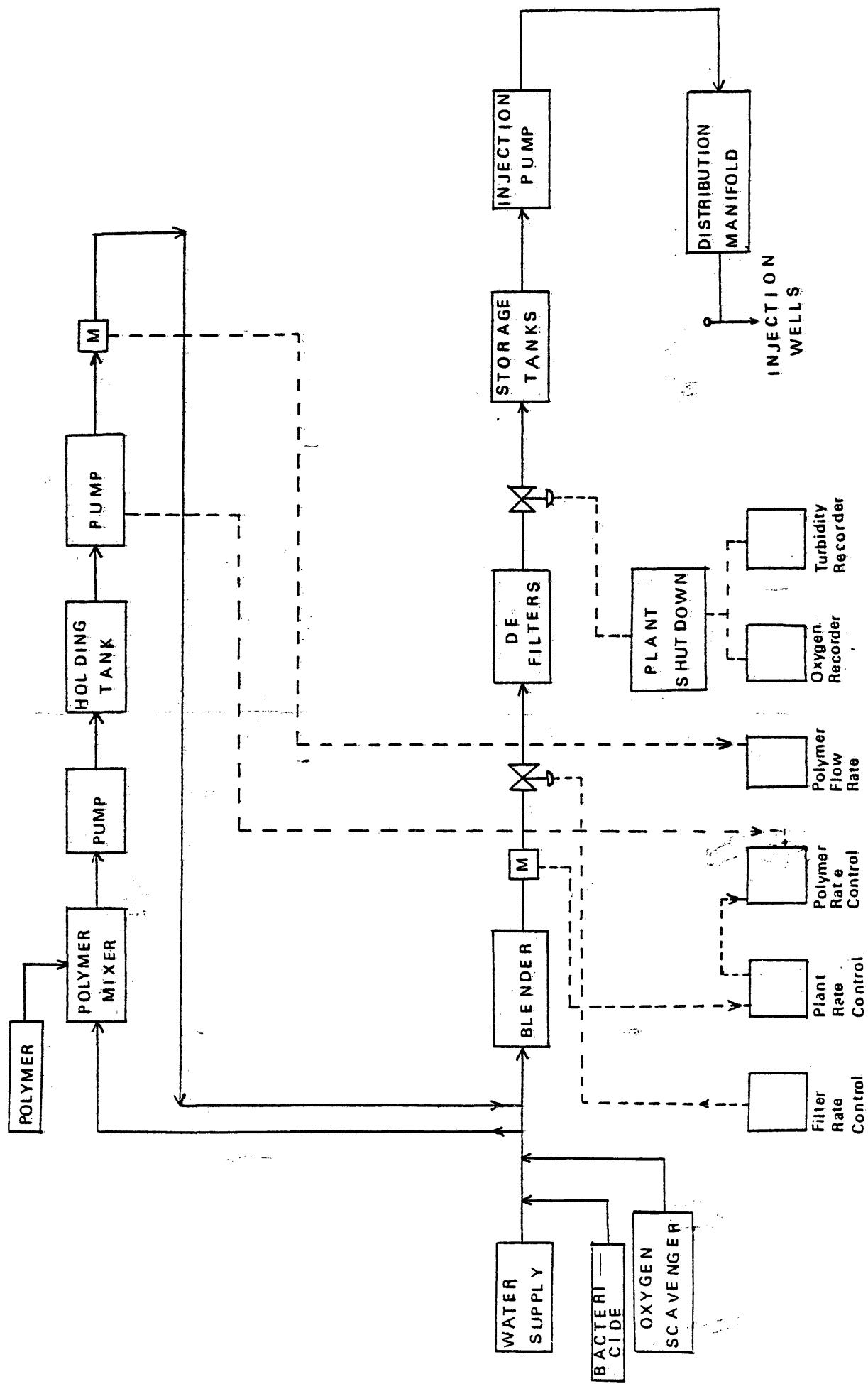
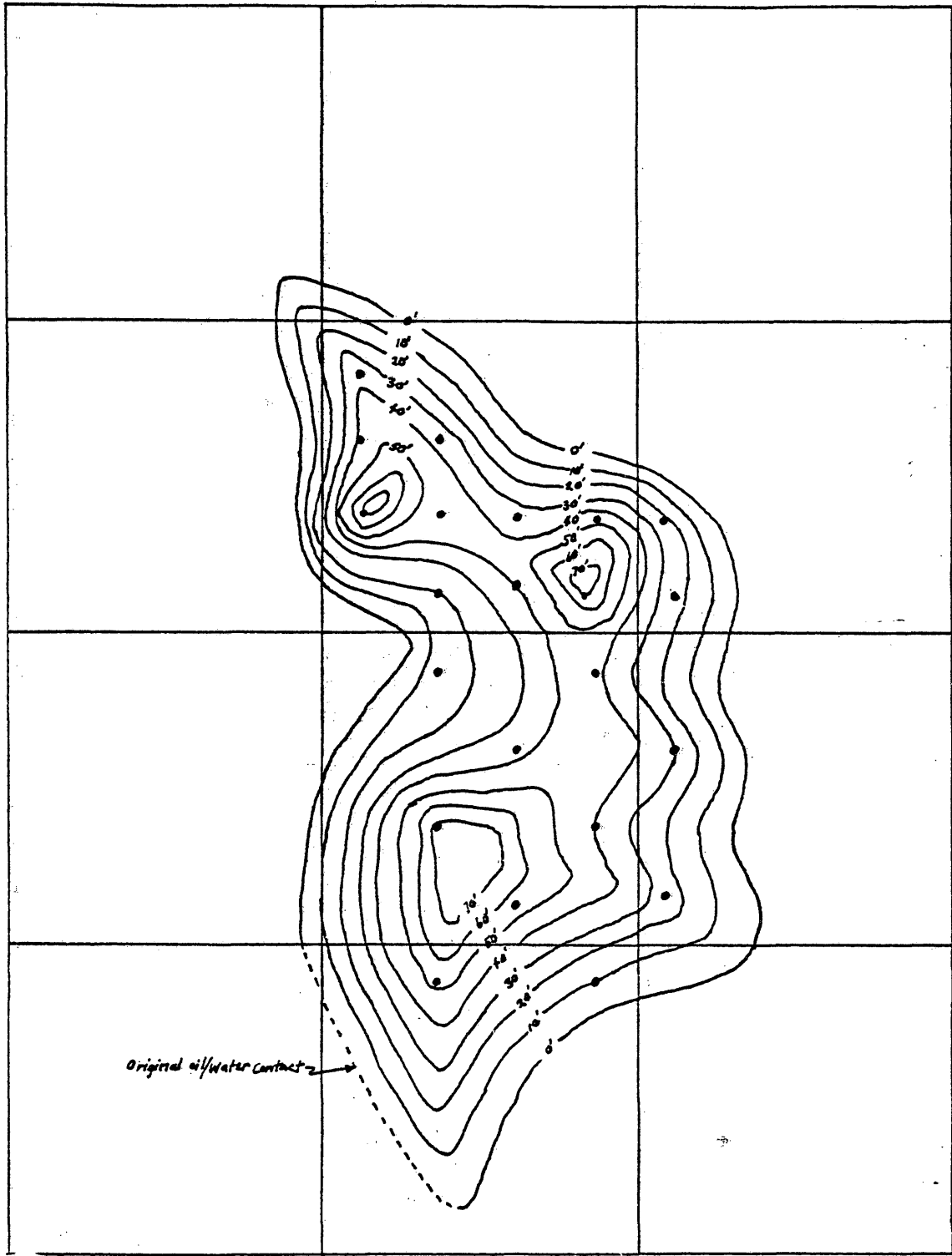


Figure 1: Polymer Mixing and Injecting Plant



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Figure 2: Isopachous Map, Net Pay, Stewart Ranch Field, Campbell County, Wyoming. (From McCartney²⁸)

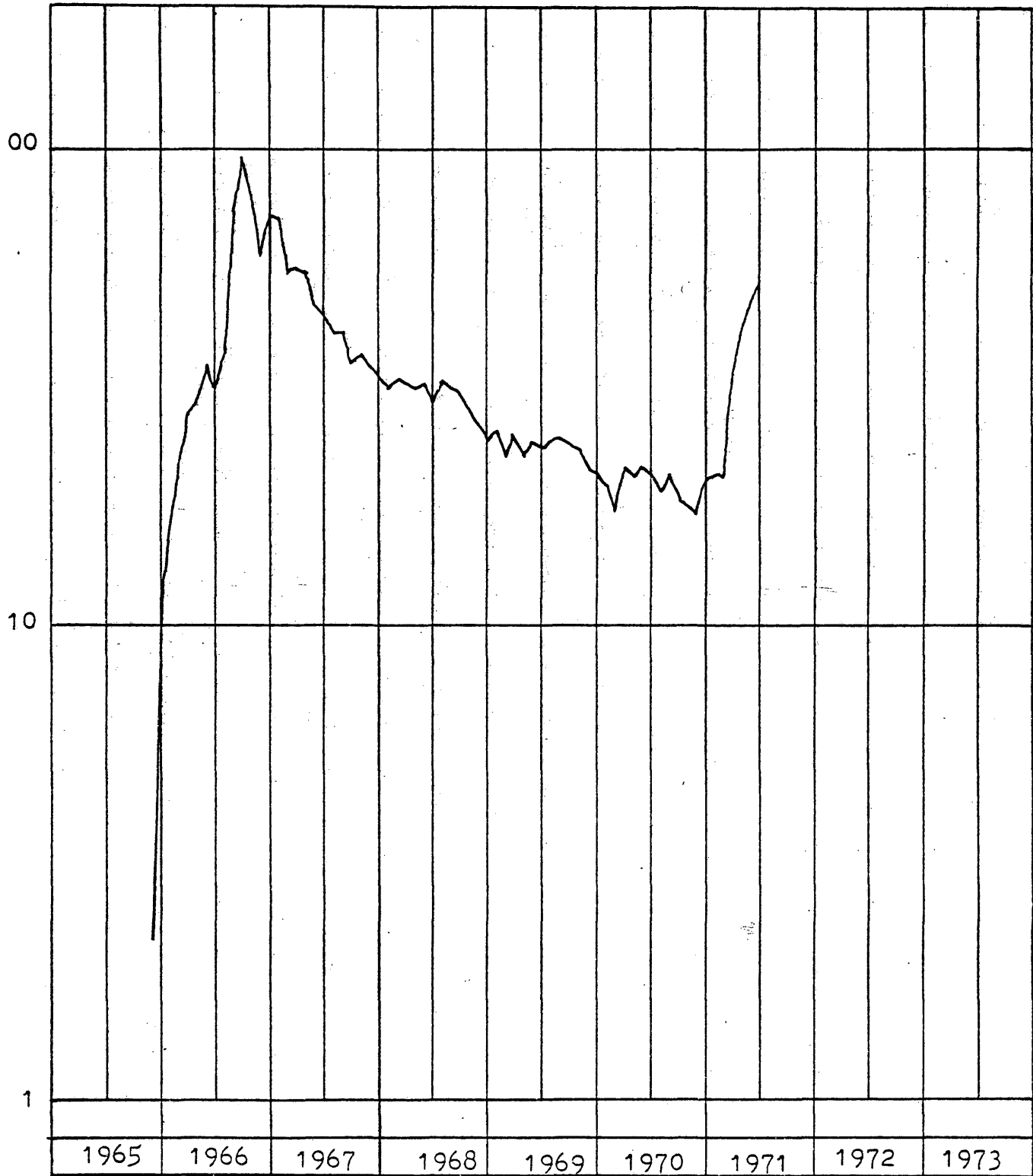


Figure 3: Oil Production History, Stewart Ranch Field, Campbell County, Wyoming. (From McCartney28)

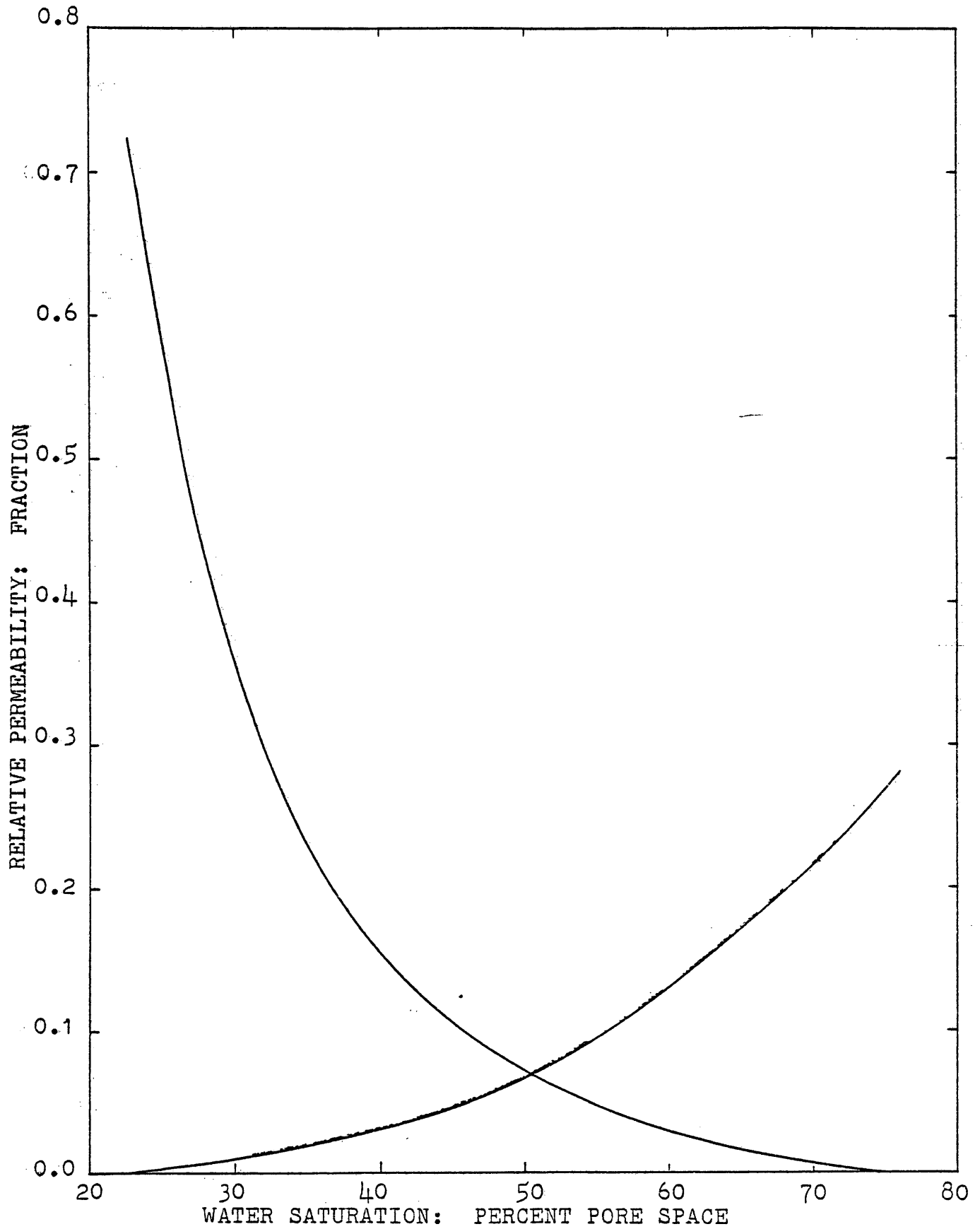
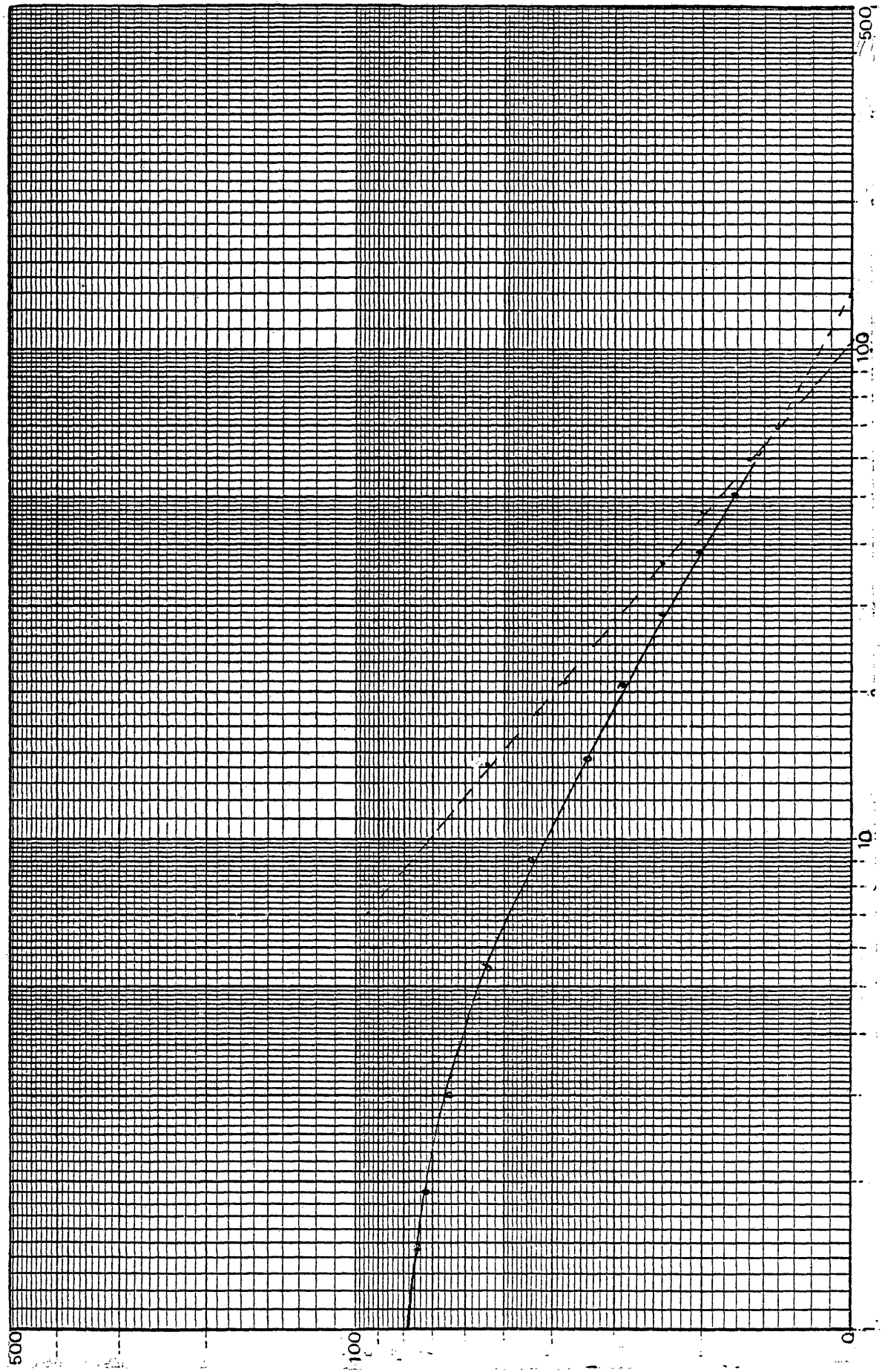
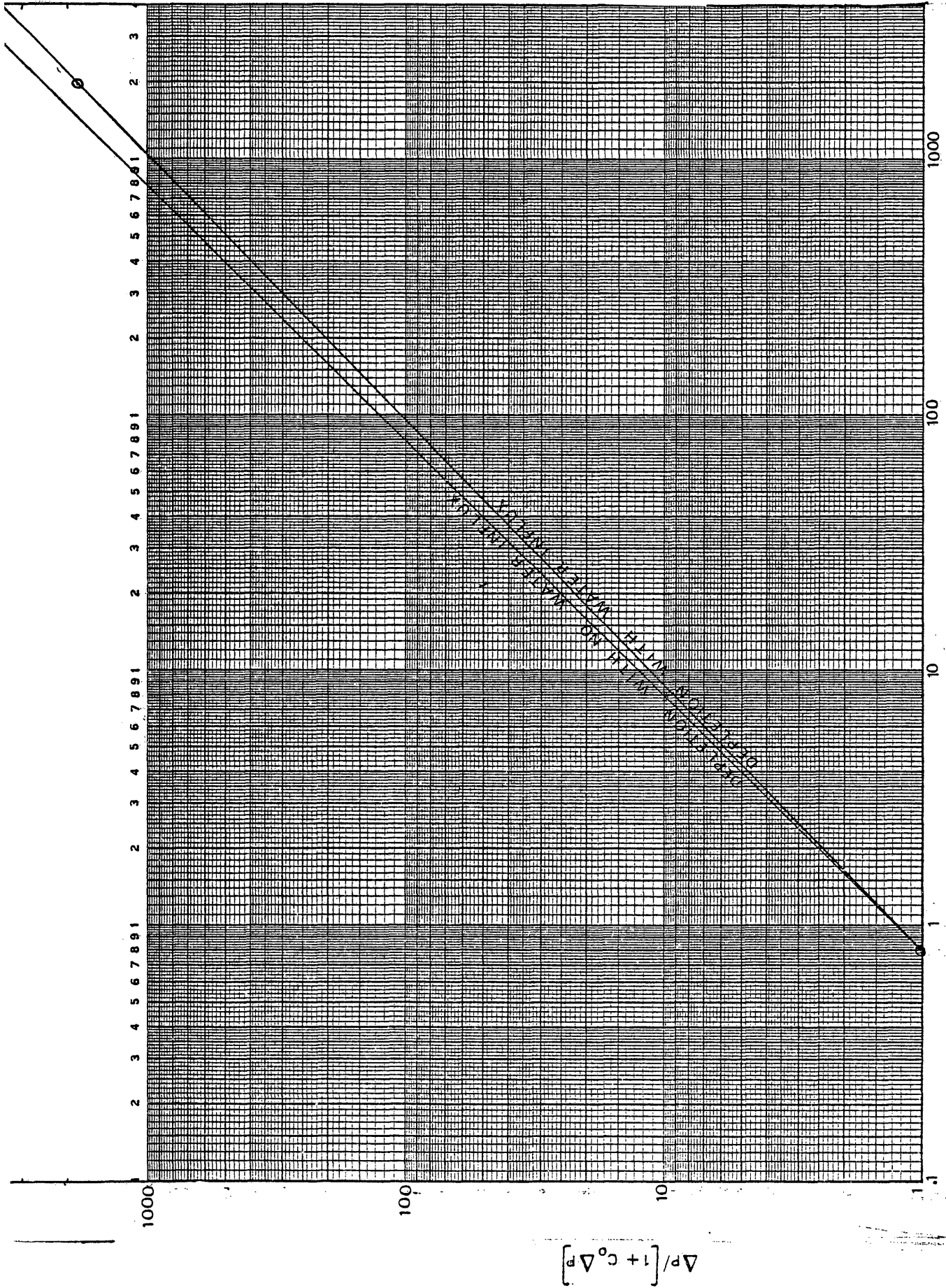


Figure 4: Relative Permeability Curves. Stewart Ranch Field, Campbell County, Wyoming. (From McCartney²⁸)



OIL PRODUCTION: BARRELS PER MONTH X 10-3

Figure 5: Oil Production Rate-Time Relationship



CUMULATIVE PRODUCTION: STOCK TANK BARRELS X 10⁻³

Figure 6: Cumulative Production - Pressure Drop Estimate

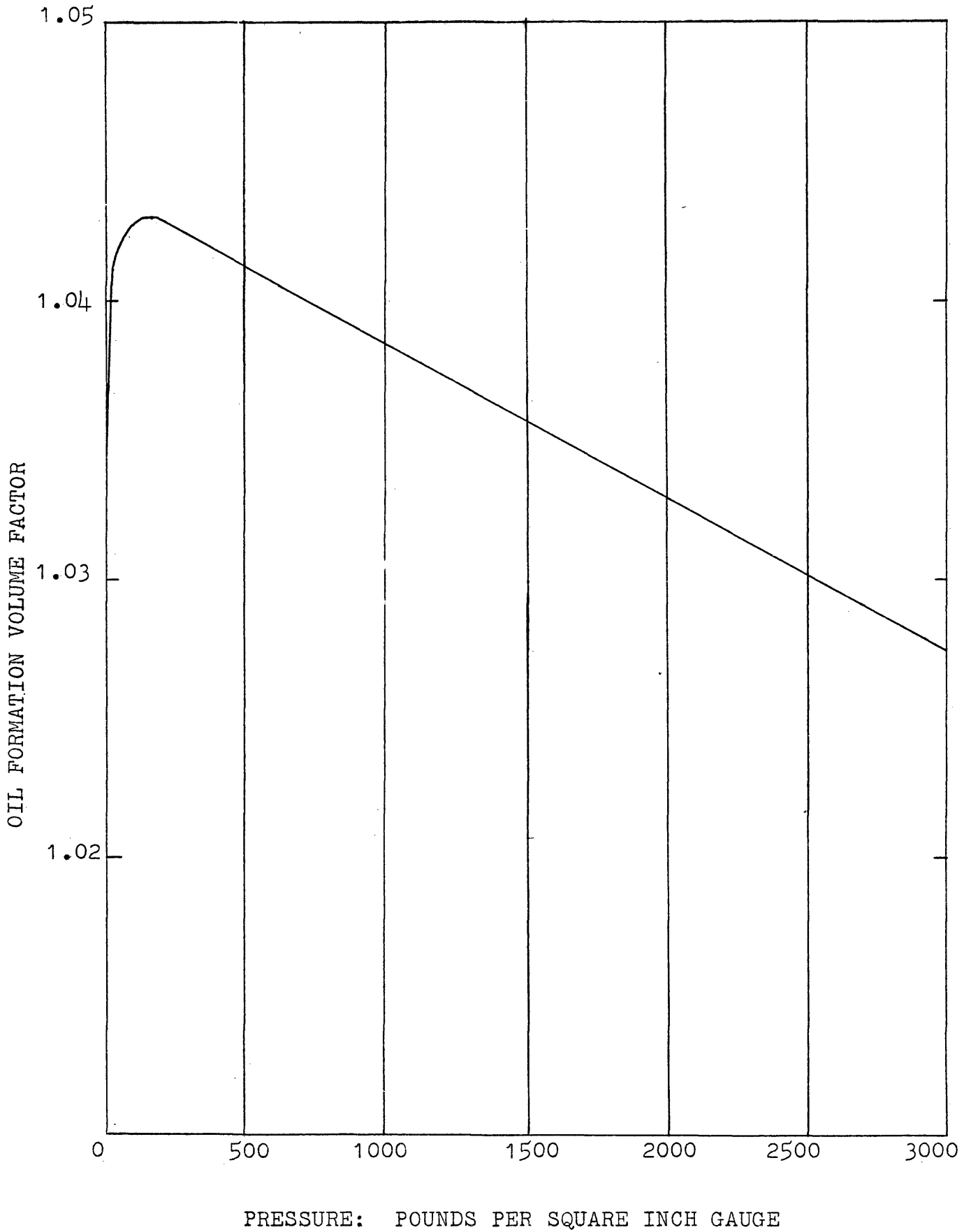


Figure 7: Oil Formation Volume Factor - Pressure Relationship

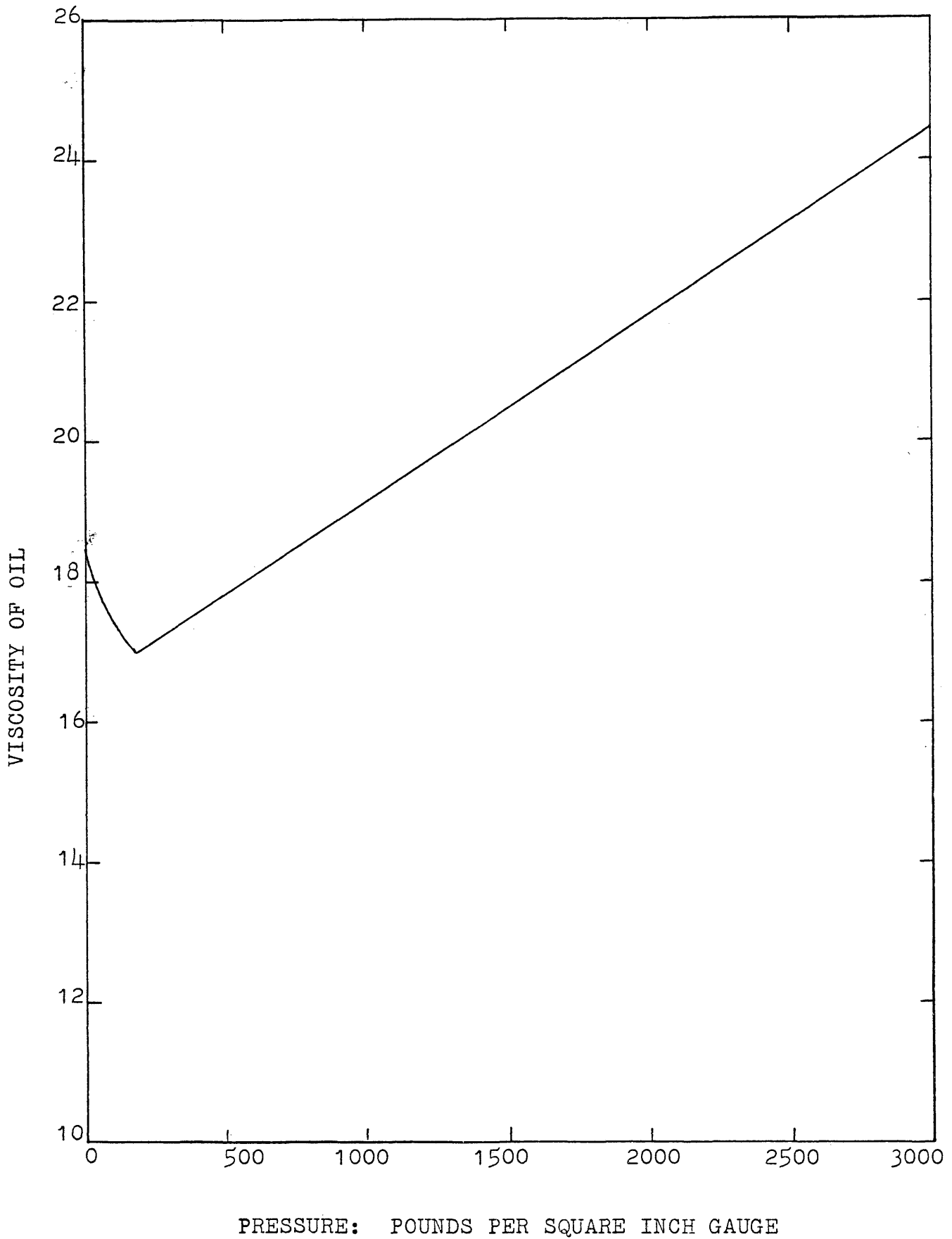


Figure 8: Viscosity of Oil - Pressure Relationship. (From McCartney²⁸)

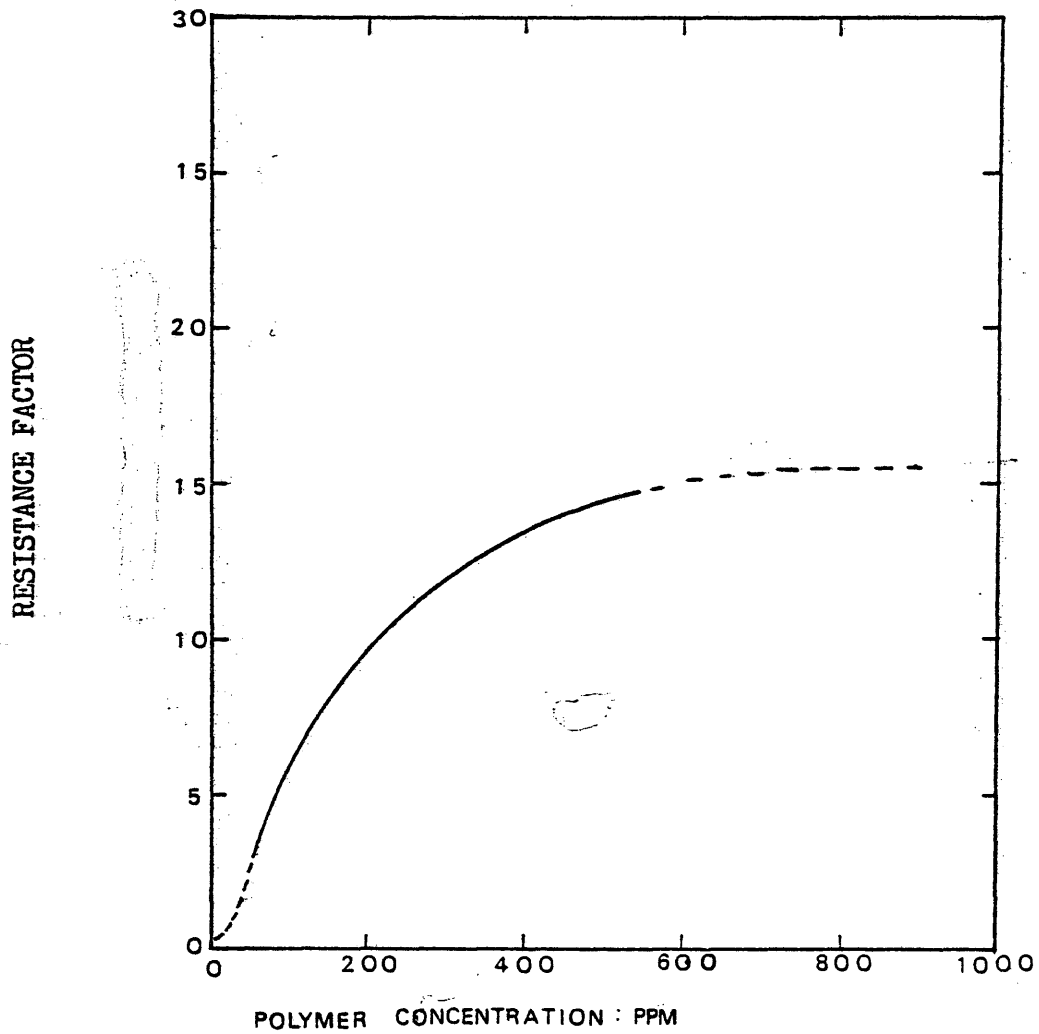
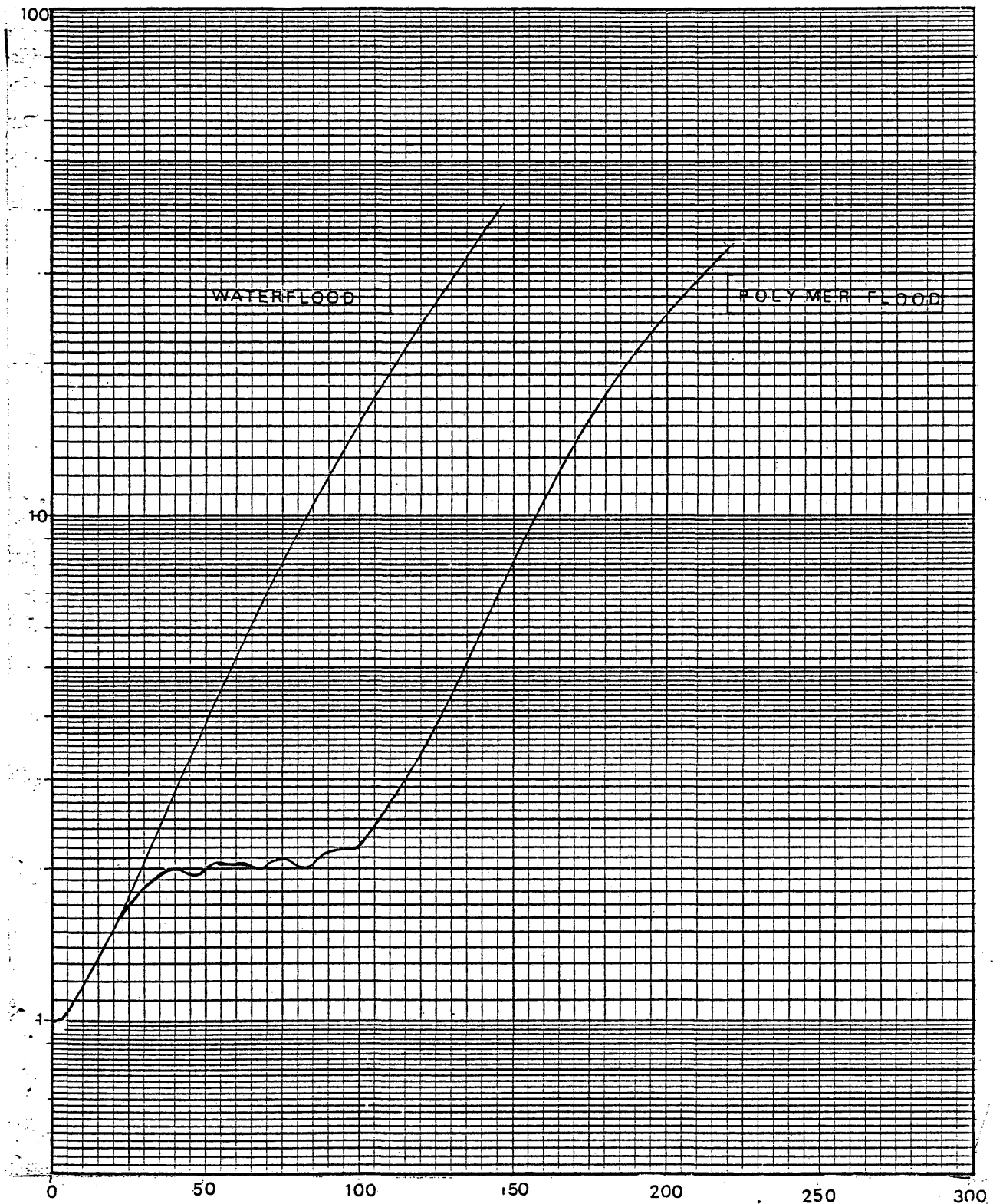


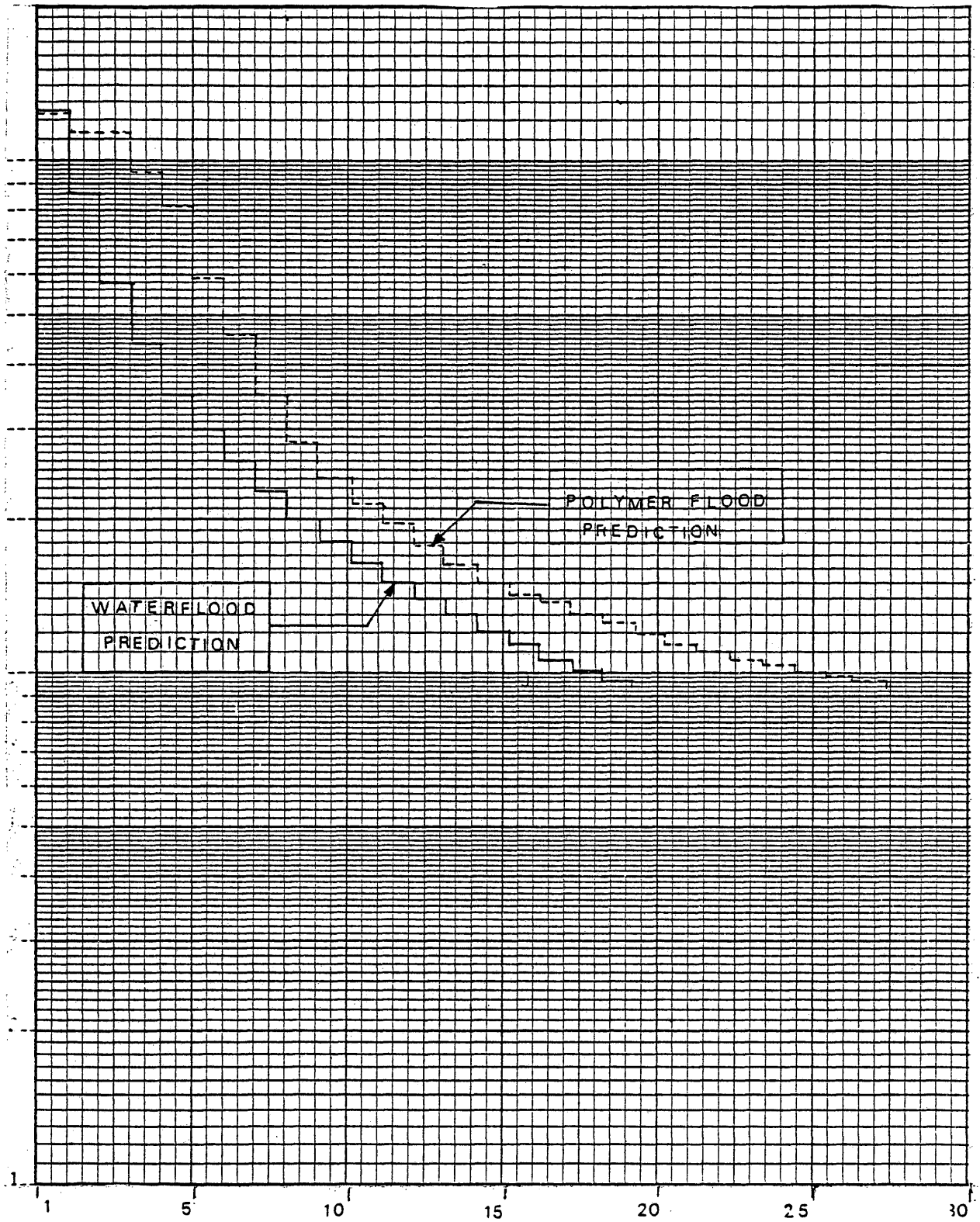
Figure 9: Resistance Factor - Polymer Concentration Relationship. (From McCartney²⁸)



Cumulative Oil Recovery: Barrels Per Ac-Ft.

Figure 10: Water-Oil Ratio - Cumulative Oil Recovery Prediction. (McCartney²⁸)

OIL PRODUCTION: BARRELS PER YEAR X 10⁻³



Time: years

Figure 11: Polymer Flood and Waterflood Time-Rate Prediction (From McCartney²⁸)

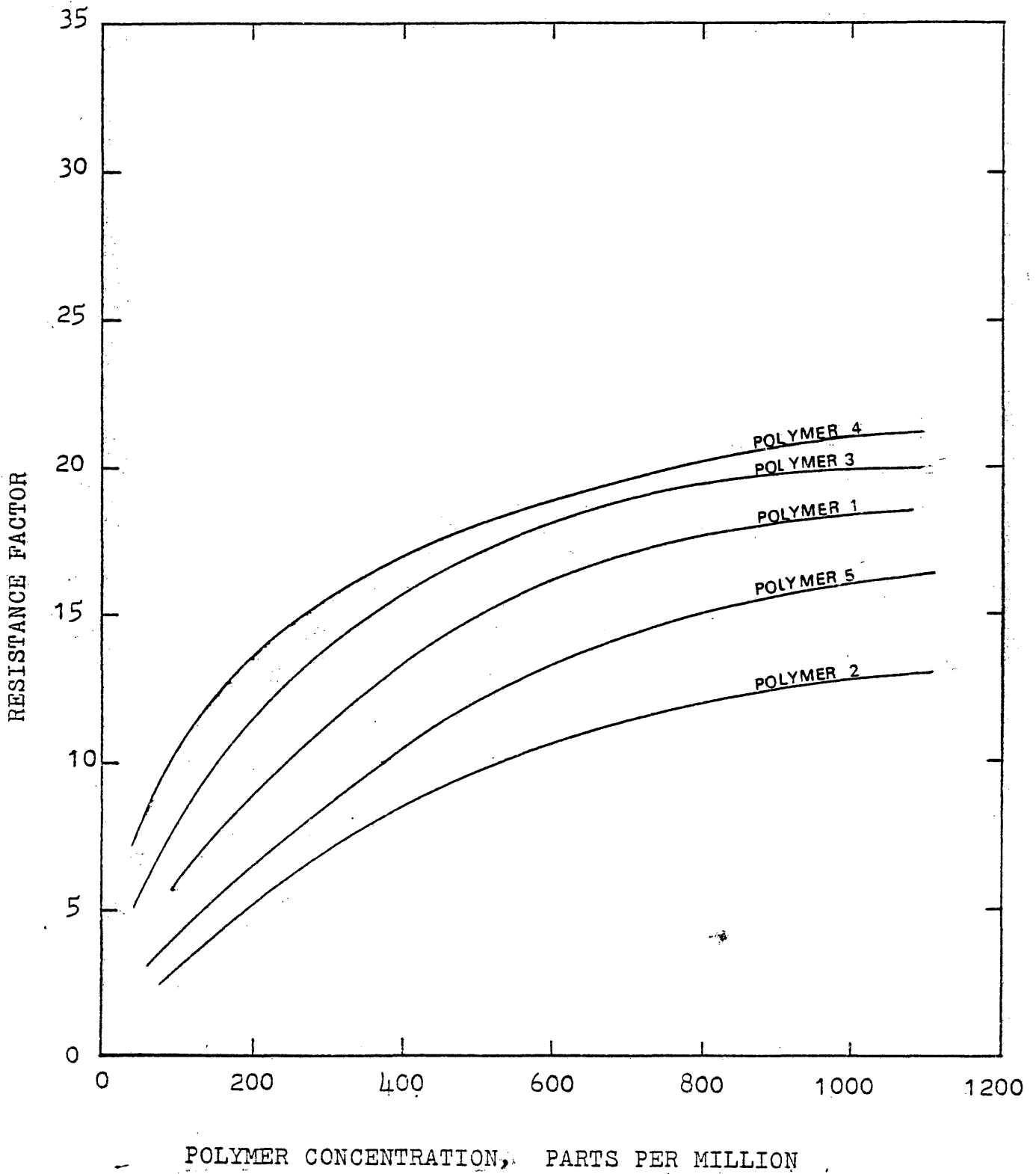


Figure 12: Resistance Factor - Polymer Concentration Relationship

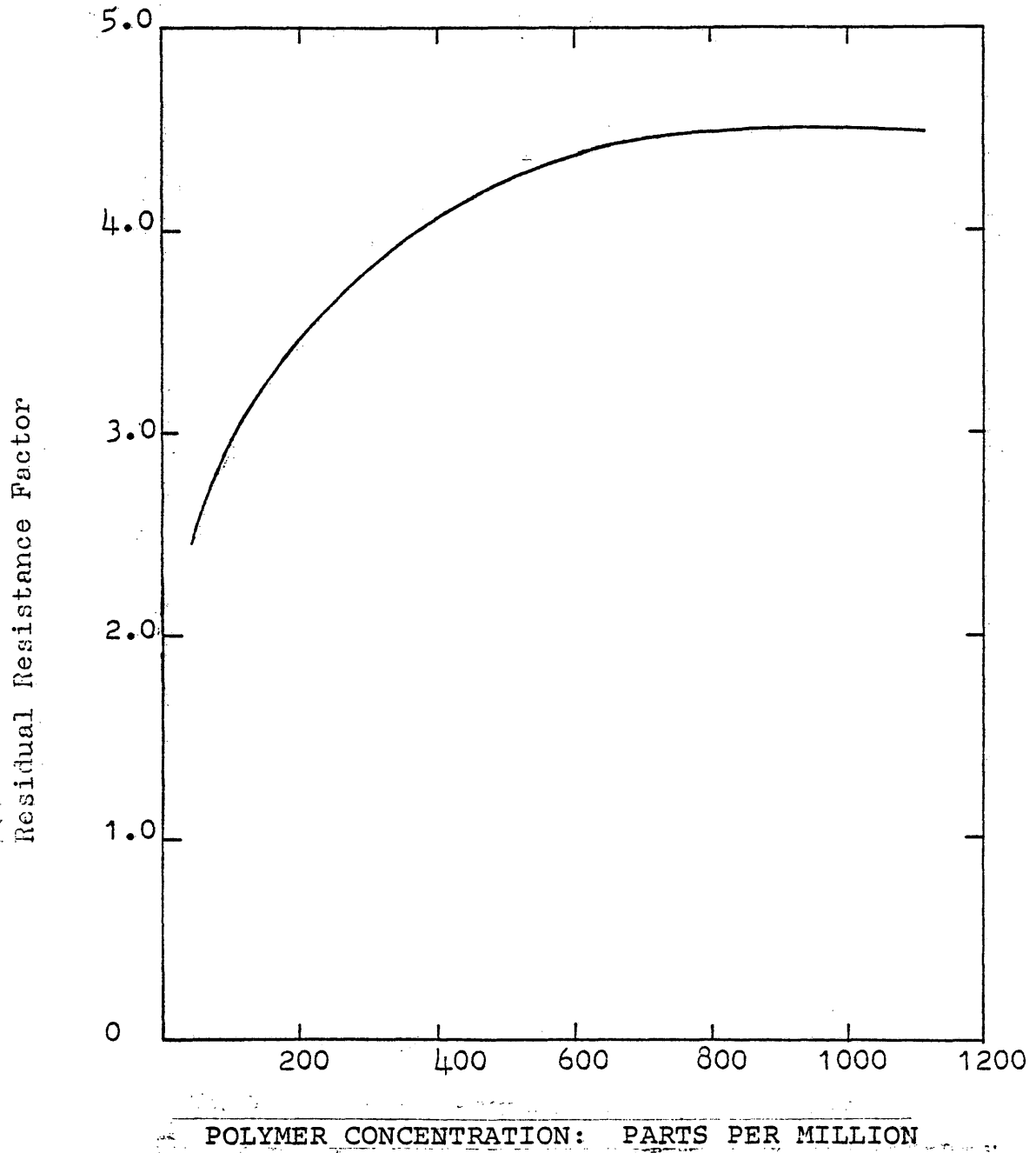
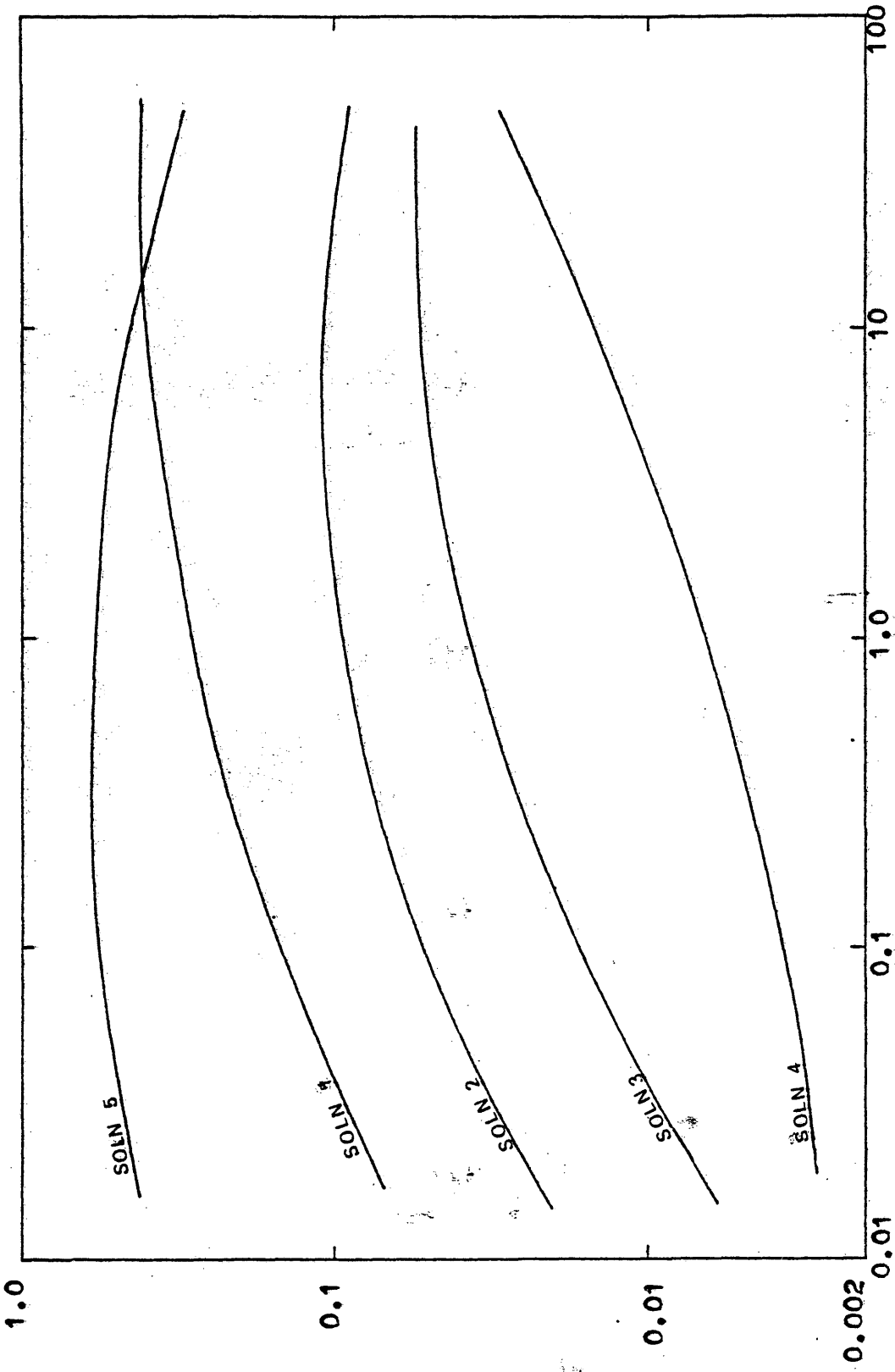


Figure 13: Residual Resistance Factor - Polymer Concentration Relationship



FRONTAL VELOCITY (FT/DAY)

Figure 14: Effect of Polymer Slug Composition on Its Mobility (From Gogarty¹³)

RELATIVE MOBILITY (CP⁻¹)

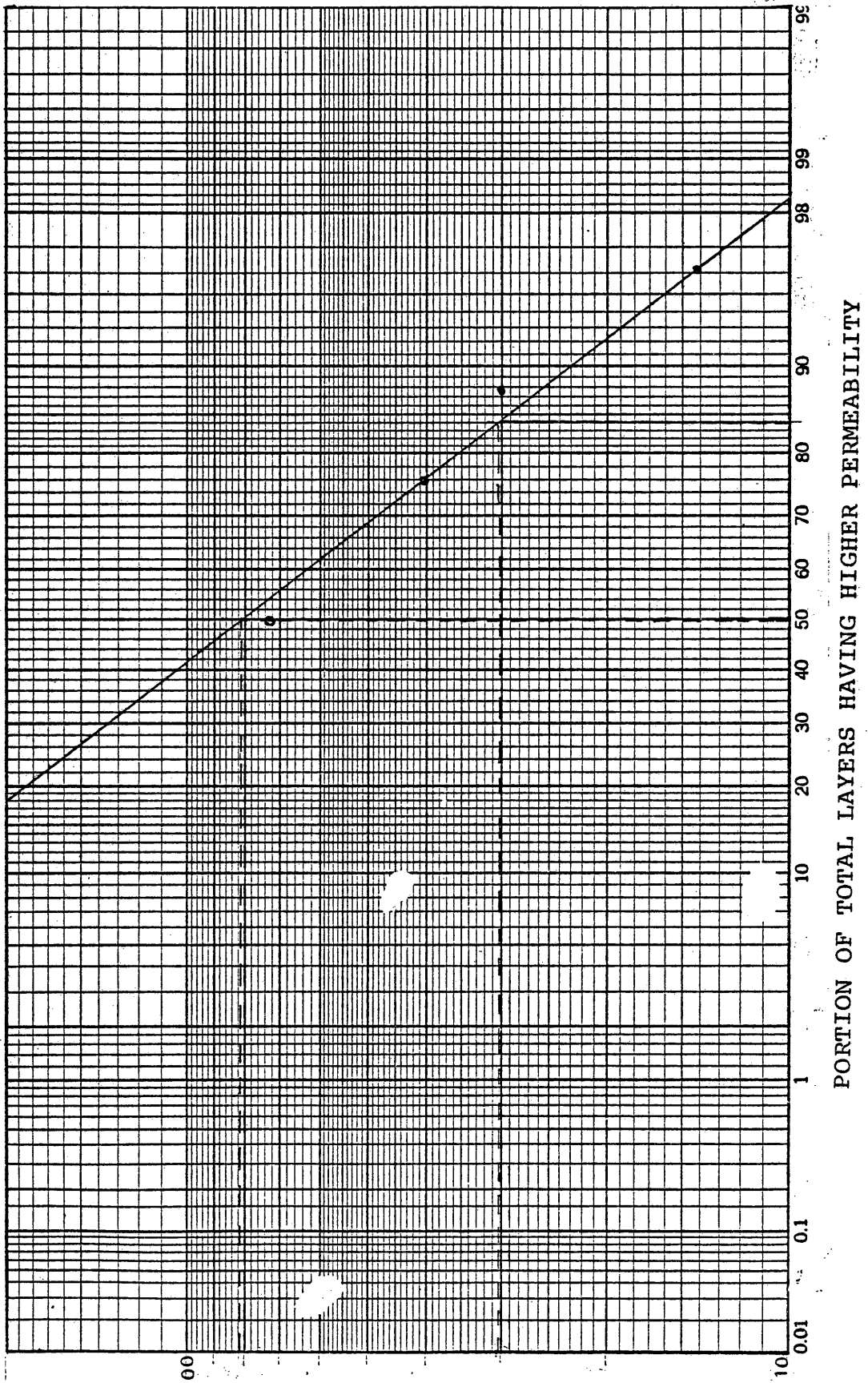


Figure 15: Log Normal Permeability Distribution

LAYER PERMEABILITY, MD

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Table 1: Model Data
(From McCartney²⁸)

Average Depth, ft.	8100
Formation Type	Sandstone
Reservoir Volume, ac-ft.	43,797,000
Reservoir Temperature, °F	2890
Original Oil in Place, STB	186
Initial Pressure, psig	900
* Estimated Pressure, November, 1972, psig	429
* Well spacing, acre	40
Existing Well Pattern	5-spot
Initial Oil Formation Volume Factor @ 2890 psig	1.028
Oil Formation Volume Factor @ 900 psig	1.039
Oil Viscosity @ 2890 psig and 136° F, cp	24.2
Oil Viscosity @ 900 psig and 136° F, cp	18.9
Oil Gravity @ 136° F, °API	28.1
P-V-T- Analysis Data	Figure 6 and Table 2
Water Viscosity, cp.	0.484
Porosity, percent	16.3
Average Permeability, md	92
Initial Water Saturation, percent	26.4
* Areal Sweep Efficiency (waterflood), percent	83.0
* Areal Sweep Efficiency (Continuous Polymer flood), percent	99.0
* Effective Fluid Compressibility, psi ⁻¹	1.802 x 10 ⁻⁵
* Well Diameter, ft.	1.0
Permeability Variation	0.625

Table 1 (Cont'd)Model Data

Polymer Resistance Factor @ 250 ppm	11
Polymer Residual Resistance Factor	3
Polymer Adsorption, lb per ac-ft	50

Layer Data For Model

<u>Layer</u>	<u>Porosity Percent</u>	<u>Permeability (millidarcys)</u>	<u>Water Saturation (percent)</u>	<u>Gas Saturation (percent)</u>
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	16.4	3.85

* included by author.

Table 2: Polymer Solution Composition

<u>Solution</u>	<u>Core Type</u>	<u>Salt Concentration in Solution Water (ppm)</u>	<u>Polymer* Type</u>	<u>Polymer Concentration (ppm)</u>
1	Pennsylvanian	450	A	1200
2	Pennsylvanian	450	A	1800
3	Berea	400	A	1400
4	Pennsylvanian	0	B	150
5	Pennsylvanian	450	B	150

*Partially-hydrolyzed polyacrylamide polymer-molecular weight of polymer B greater than that of Polymer A. Polymer A is Dow Pusher Series 500, and Polymer B is Dow Pusher Series 700.

Table 3: Fluid Analysis Data

Pressure psig	Pressure-Volume Relation @ 139°F Relative Volume of Oil and Gas V/V_{sat} .	Viscosity of Oil @ 139°F Centipoises	DIFFERENTIAL Gas/Oil Ratio Liberated Per Barrel of Residual Oil	LIBERATION @ 139°F Relative Oil Volume V/V_r
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	0	1.042
186	1.0000	17.0		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

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