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FOSSIL ENERGY

ASSESSMENT OF POTENTIAL INCREASED OIL PRODUCTION BY POLYMER-WATERFLOOD IN NORTHERN AND SOUTHERN MID-CONTINENT OIL FIELDS

Final Report

Work Performed for the Department of Energy
Under Contract No. EW-78-C-19-0026

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Gruy Federal, Inc.
Houston, Texas

U. S. DEPARTMENT OF ENERGY

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Final Report

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U.S. DEPARTMENT OF ENERGY

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ABSTRACT

A conventional waterflood in the North Stanley Field, Osage County, Oklahoma, nearing the economic limit, was modified by substituting an aqueous solution of polyacrylamides for brine as the injected fluid. Remedial operations on existing facilities were performed before polymer injection before polymer injection began. The project was supported by the U.S. Department of Energy (DOE) as a test, under recognized adverse conditions, of a reservoir which is representative of a large segment of the reserves in the Mid-Continent waterflood properties. A successful outcome would provide incentive for widespread application in the Mid-Continent region.

Positive oil production response was achieved from this 1000-acre project, a maximum EOR production rate of about 200 barrels per day being achieved within 1-1/2 years after the start of polymer injection. Based on performance to January 1979, ultimate EOR recovery is estimated at 500,000 barrels, which is not sufficient to provide adequate economic incentive for commercial application under similar circumstances. The results, however, provide useful insight into the effects of such factors as geological parameters and stage of depletion by prior waterflooding on the outcome of mobility control processes. The results also provide encouragement for modernization of currently active waterflood projects through well workovers, selective plugging, pattern modifications, balanced injection rates, etc., the aggregate effect of which is believed to have contributed significantly to the improved performance of the North Stanley project.

The amount of oil remaining in the reservoir, which could be considered the target for mobility control at the time of application, was 0.08 pore volumes, or approximately 13 percent of stock tank oil in place. Of this, the project recovered about 0.007 pore volumes, or about 9 percent of the target.

In view of the positive though not economic production response of this project, the screening criteria for the polymer-augmented waterflood process were reviewed. The current upper water-oil ratio upper limit of 15 appears to be too restrictive. Channeling and fractures have been considered prohibitive in earlier screenings, but these problems can be mitigated to some extent by the use of selective plugging techniques; thus a candidate should be rejected only if conditions are too severe to permit conventional waterflooding. Further results of this review suggest that a field having adequate permeability for conventional waterflooding should have adequate permeability for polymer-augmented waterflood. Mobile oil saturation of 0.10 pore volume and a crude oil gravity between 16 and 42° API are within the range of feasibility for this process. However, these screening criteria are only guidelines for rejecting least likely candidates; they are inadequate for any degree of specific prospect evaluation.

The Petroleum Data System files on this area were searched for fields that would pass a minimal screening, including:

1. At least one sandstone reservoir

2. A total cumulative production of greater than 1,000,000 barrels of oil

3. Five or more producing wells

4. Pay interval thickness at least 5 feet

5. Oil gravity in the range 16-42° API.

6. No evidence of uncontrolled waterflooding.

Using these criteria, 730 fields containing 2499 reservoirs were identified within the region. The geologic and engineering characteristics of 88 of the above fields currently producing of 200,000 barrels of oil per day or more were reviewed in depth. These 88 fields contain 732 reservoirs.

It is estimated that currently active projects in the area studied contain 1.7 billion barrels of mobile oil that will not be recovered by continuation of conventional waterflooding operations. This represents, therefore, a proved mobile resource. On a project basis, the target for mobility control in a typical Mid-Continent waterflood has been estimated to be 0.10 pore volumes, or about the same as the anticipated ultimate waterflood recovery under present economic conditions. A liberal estimate of average potential target recovery is about 0.012 pore volumes, or 12 percent of the existing target. However, due largely to the adverse effects of the advanced stage of depletion of most Mid-Continent waterfloods and the economic risk involved in large-scale chemical application at this time, the estimated recovery potentially available through reservoir-wide mobility control measures as of January 1979 is on the order of 100 million barrels. The probable actual realization of this immediate target is expected to be less, perhaps as low as 50 million barrels, because of anticipated delays in effecting specific projects, progressive reductions in the potential with continued waterflooding (possibly aggravated by improved waterflooding economics), and priority application of other processes with greater recovery potential.

ASSESSMENT OF POTENTIAL INCREASED OIL PRODUCTION BY POLYMER-WATERFLOOD IN NORTHERN AND SOUTHERN MID-CONTINENT OIL FIELDS

INTRODUCTION

From the beginning of efforts to apply "controlled" waterflooding in the Mid-Continent region in the 1930's, the problem of effectively controlling the distribution of injected fluid was recognized as being of paramount importance. Little progress was made, however, beyond the development of some partially effective techniques for injectivity profile measurements and for selective plugging.

A valuable aid to project design, interpretation, and evaluation was provided in the early 1950's with the recognition that a complex system of flow geometry (even in uniform reservoirs and well patterns) and differences in mobility between indigenous and injected fluids were interrelated influences on recovery efficiency. No important developments occurred to permit taking advantage of this improved understanding of fluid flow, however, until the advent of polymer-augmented waterflooding in 1964. Aqueous polymer solutions have flow characteristics capable of mitigating, to some degree, the effects of unfavorable combinations of flow geometry and fluid mobilities.

This report presents the results of Gruy Federal's evaluation of the potential of the polymer-enhanced waterflood recovery process in a portion of the Mid-Continent oil producing region, conducted under Contract No. EW-78-C-19-0026 with the U.S. Department of Energy. Four steps were involved in this study.

First, the polymer waterflood in the North Stanley Stringer Field, Osage County, Oklahoma, was thoroughly reviewed and evaluated.

Second, criteria for region-wide field screening of candidate reservoirs were reviewed and revised as deemed appropriate.

Third, the geological and engineering features and statistical performance of the oil fields in the study area were reviewed.

Fourth, ranges of increased oil productivity that could result from future regional application of the polymer-augmented waterflood technique were estimated on the basis of the results of the preceding steps.

I. EVALUATION OF THE NORTH STANLEY STRINGER POLYMER-ENHANCED WATERFLOOD PROJECT

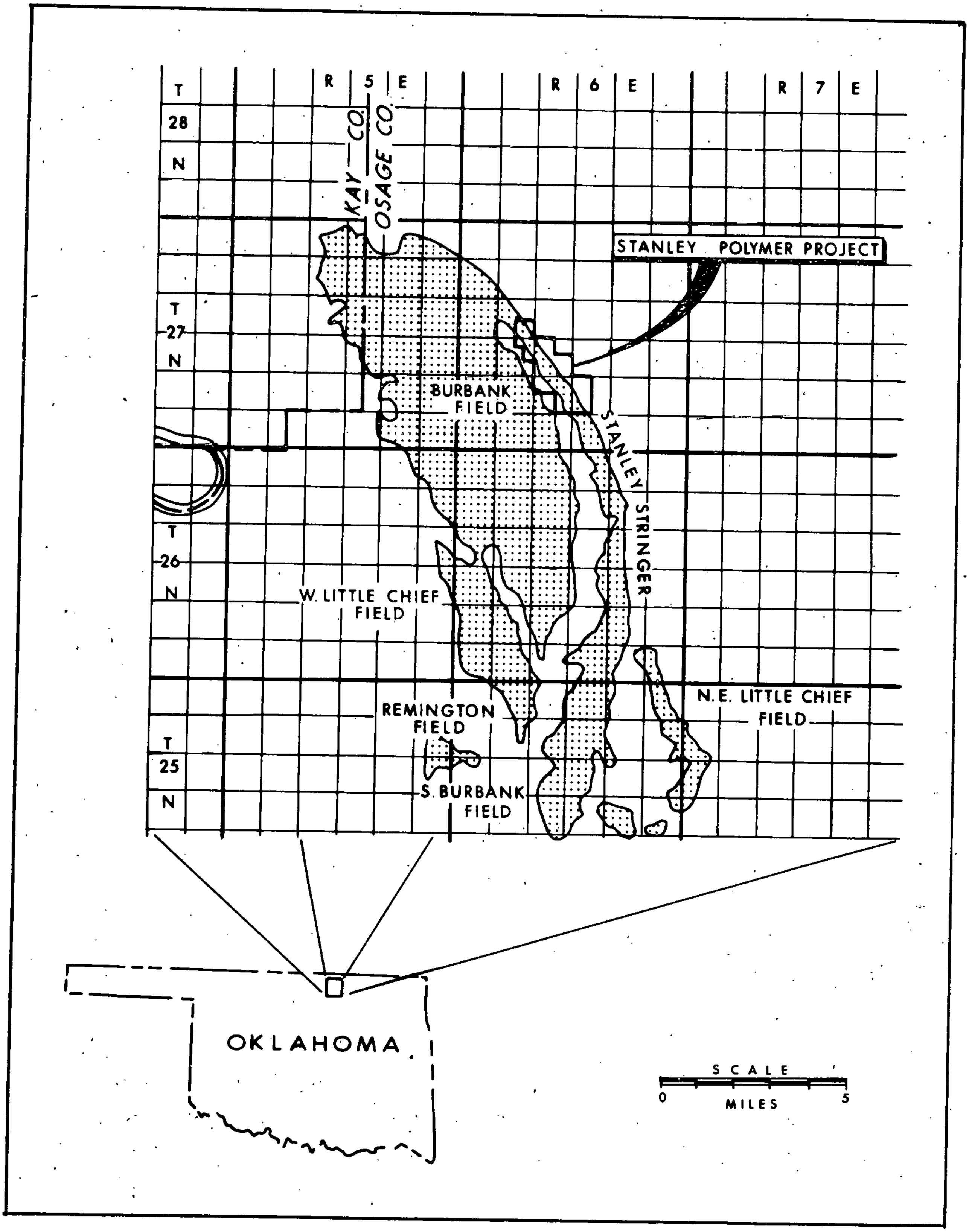
The North Stanley Stringer polymer-augmented waterflood project was jointly funded by the Kewanee Oil Company and the U.S. Department of Energy (DOE) for the purpose of determining (1) the efficiency of polymer-augmented waterflooding applied at a late stage of waterflood depletion in a heterogeneous sandstone reservoir, and (2) whether the process would be economic at current oil prices. Favorable results could demonstrate a large potential for increased recovery from similar reservoirs in the study area.

Kewanee has completed the polymer injection phase and injection operations have reverted to produced brine. Although the estimated ultimate incremental oil recovery from the project is insufficient for an adequate economic return, the project has demonstrated a definite positive response under particularly adverse conditions. It thus provides encouragement for remedial work in existing waterfloods and for the application of crosslinked polymers as selective plugging agents under severe conditions of channeling and fracturing. Other remedial engineering activities can include: selective control of injection profile, pattern alterations, optimum balance of rates and pressures, and remedial well operations where appropriate.

Reservoir complexities posed major problems for the Kewanee project. The potential deleterious effects of these complexities were recognized early in the project and appropriate remedial operations were undertaken, with varying degrees of success. Production response to polymer injection was affected not only by the basic flow geometry but also by the remedial operations, as discussed in the following section.

Geology of North Stanley Stringer Field

The North Stanley Stringer Field, located in Township 27 North, Range 6 East, Osage County, Oklahoma (Fig. 1), projects southeasterly from the



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INDEX MAP

KEWANEE NORTH STANLEY

POLYMER AUGMENT FLOOD

OSAGE COUNTY, OKLAHOMA

FIGURE 1

northern portion of the Burbank Field. It produces from the middle Pennsylvanian Burbank sandstone member of the Cherokee shale. Both fields produce from the same horizon and have similar depositional histories.

Regional dip in the area, measured on the Oswego lime 150-200 feet above the Burbank sandstone, is southwest at 30-40 feet per mile.

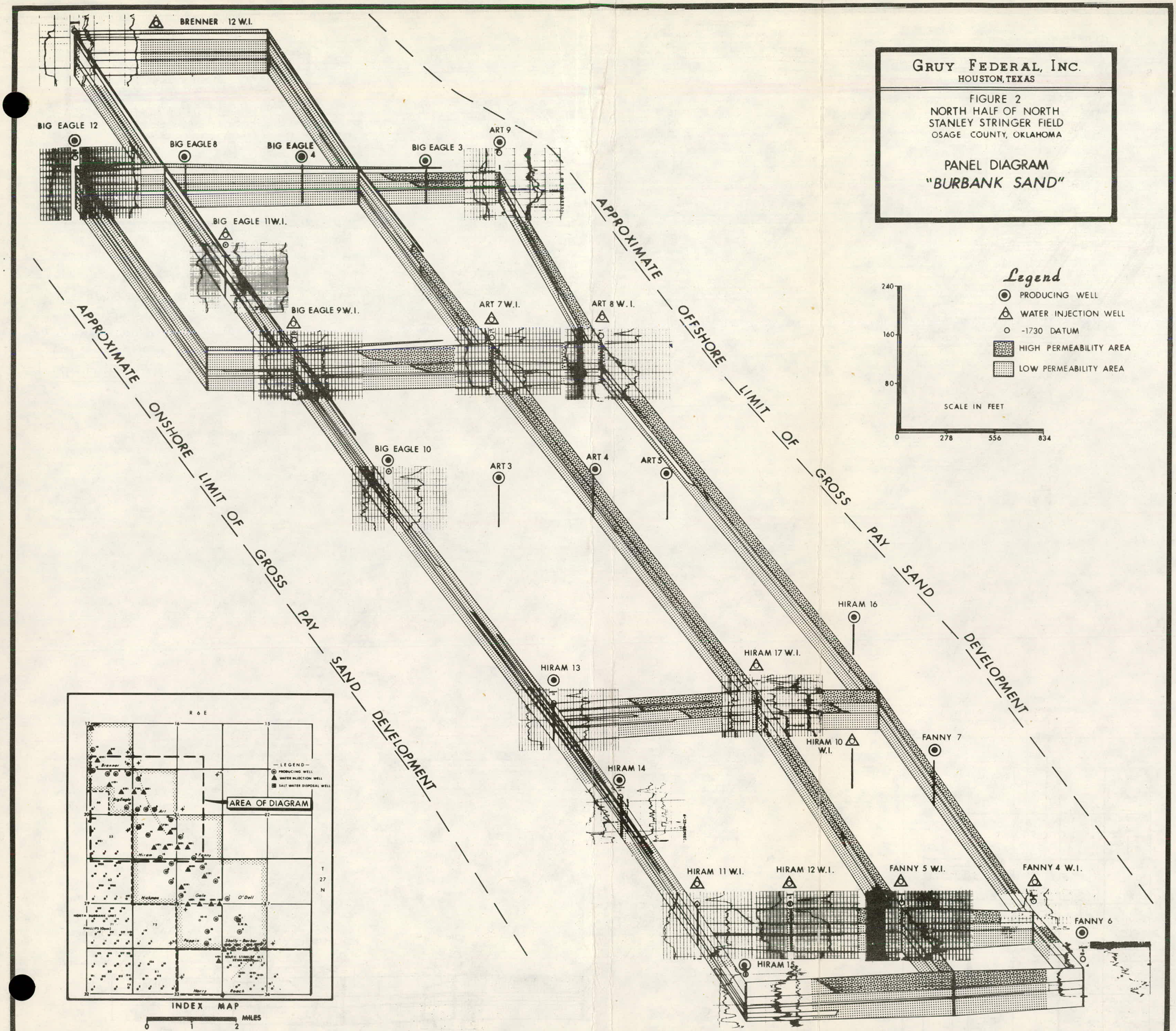
The Stanley Stringer Field, 1/2 to 3/4 mile wide and 15 miles long, has been interpreted as an offshore bar deposit (Sands, 1927; Bass and others, 1937; Bass and others, 1942; Cruz, 1966). Bass and others (1937) postulated bar development along the western margin of the Cherokee Sea during Pennsylvanian time, with the Stanley Stringer representing a stage of development subsequent to the deposition of sands in the Burbank Field. Hudson (1970) provided evidence of a fluvial origin for sands in this region, and Phillips Petroleum Company (1976) suggested a fluvial origin for the Burbank sands in the Burbank Field, based on petrographic studies of cores.

The sand body in the northern portion of the Stanley Stringer Field is 32 to 84 feet thick, with the axis of maximum sand development positioned toward the seaward side. The facies change from sand to shale is abrupt on the seaward side, but less so on the lagoonal side. The sand is composed of three zones, with shale or fine sand laminae separating the individual sands on the backbar or lagoonal side. In some areas the thin layers extend entirely across the field.

Petrographic studies by Leatherock (1937) show the Burbank sands to be predominantly fine grained, ranging in size from 1/8 to 1/4 mm in diameter. Clay content is commonly around 10 percent, but can be as high as 40 percent. The producing horizons lie at depths of 2850 to 2950 feet.

Reservoir Heterogeneity.

Figures 2 and 3 are panel diagrams showing the sand development in the field. Logs used in constructing these diagrams include SP, gamma ray,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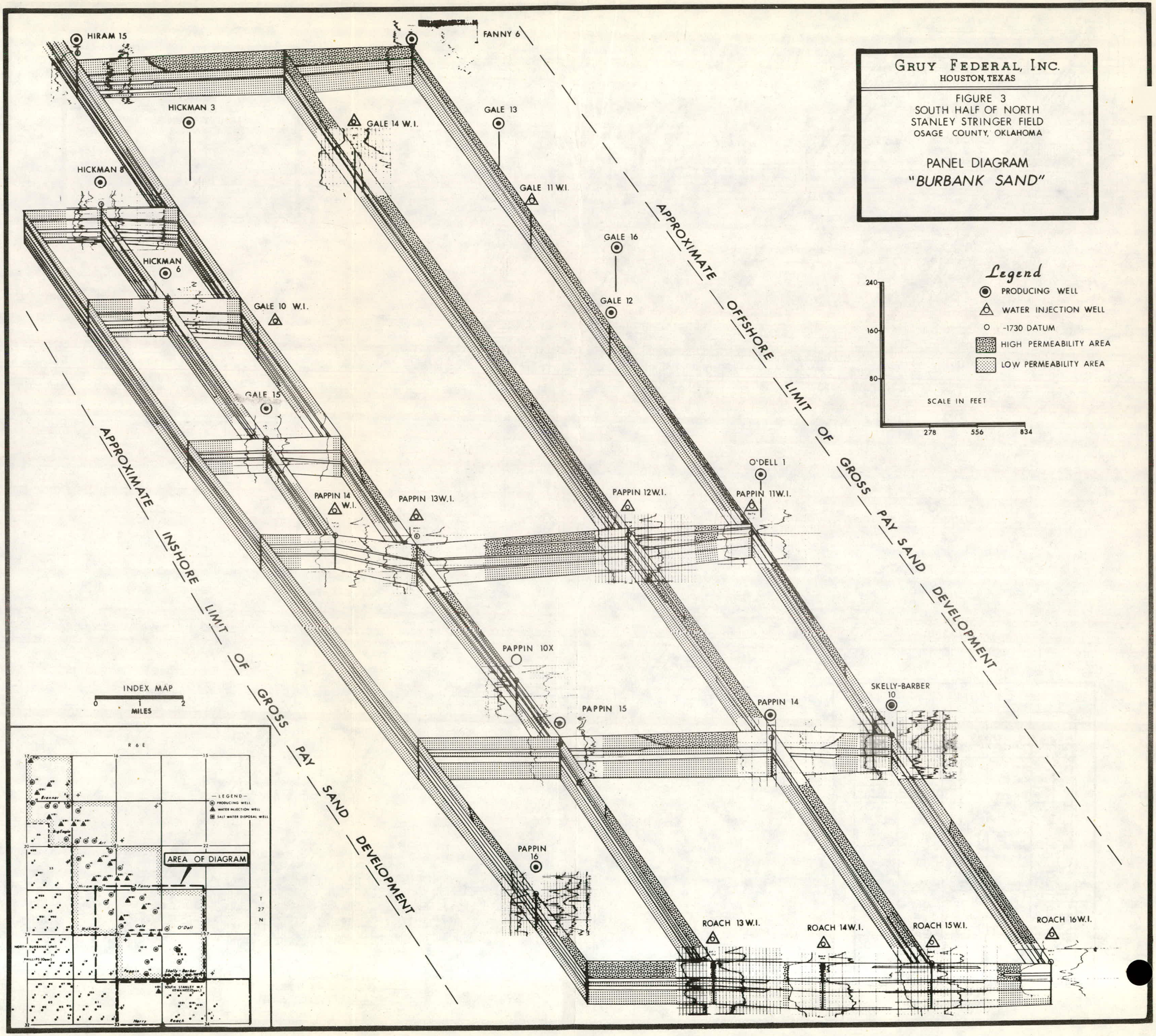
HOUSTON, TEXAS
FIGURE 2
NORTH HALF OF NORTH
STANLEY STRINGER FIELD
OSAGE COUNTY, OKLAHOMA
PANEL DIAGRAM
"BURBANK SAND"
Legend
PRODUCING WELL
WATER INJECTION WELL
-1730 DATUM
HIGH PERMEABILITY AREA
LOW PERMEABILITY AREA
240
160
80
0
278
556
834
SCALE IN FEET
BRENNER 12 W.I.
BIG EAGLE 12
BIG EAGLE 8
BIG EAGLE 4
BIG EAGLE 3
ART 9
BIG EAGLE 11 W.I.
BIG EAGLE 9 W.I.
ART 7 W.I.
ART 8 W.I.
BIG EAGLE 10
ART 3
ART 4
ART 5
HIRAM 16
HIRAM 17 W.I.
HIRAM 13
HIRAM 10 W.I.
FANNY 7
HIRAM 14
HIRAM 11 W.I.
HIRAM 12 W.I.
FANNY 5 W.I.
FANNY 4 W.I.
FANNY 6
HIRAM 15
APPROXIMATE OFFSHORE LIMIT OF GROSS PAY SAND DEVELOPMENT
APPROXIMATE ONSHORE LIMIT OF GROSS PAY SAND DEVELOPMENT
R 6 E
T 27 N
AREA OF DIAGRAM
INDEX MAP
0 1 2 MILES



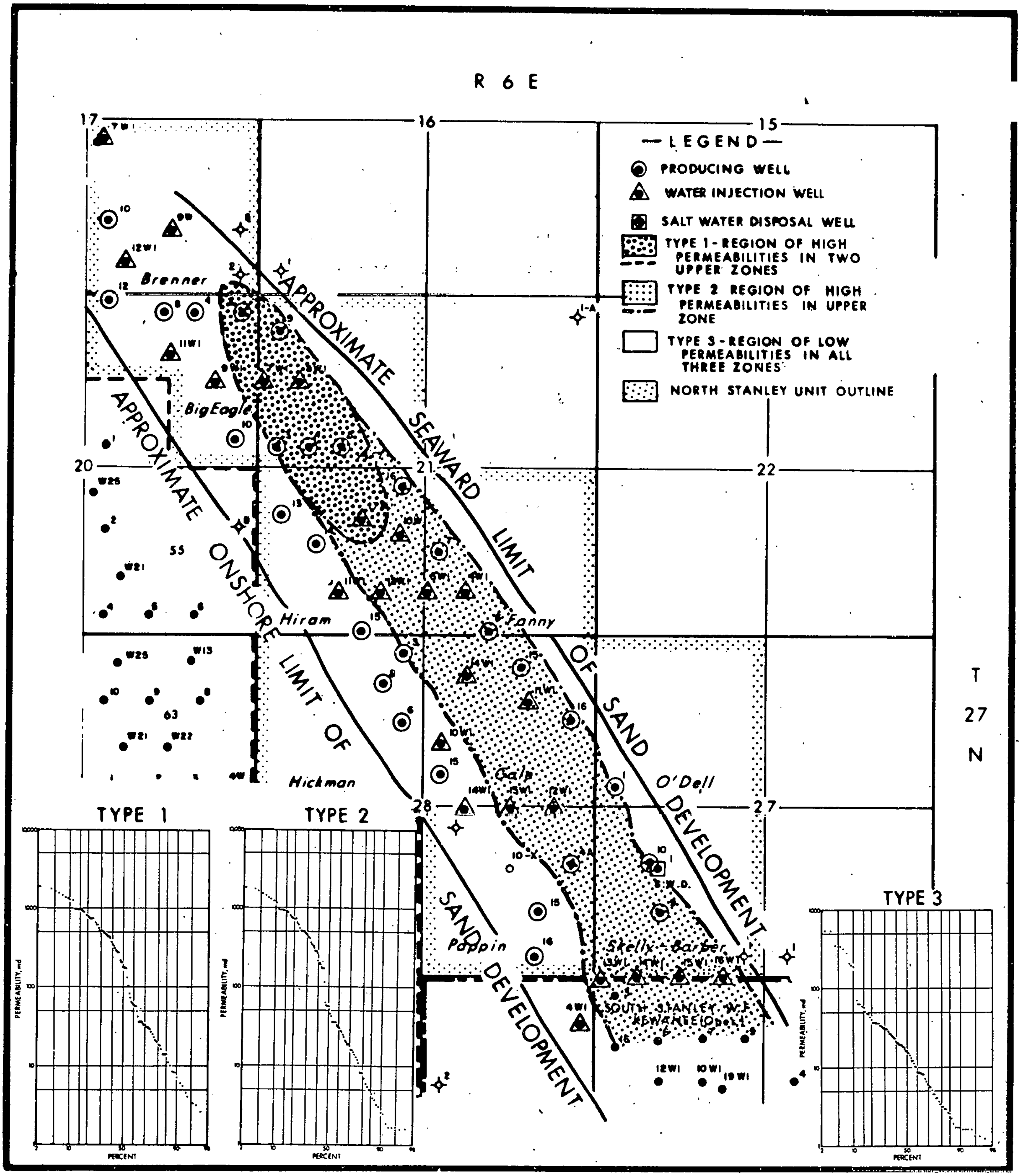
GRUY FEDERAL, INC.
HOUSTON, TEXAS
FIGURE 3
SOUTH HALF OF NORTH
STANLEY STRINGER FIELD
OSAGE COUNTY, OKLAHOMA
PANEL DIAGRAM
"BURBANK SAND"
Legend
PRODUCING WELL
WATER INJECTION WELL
-1730 DATUM
HIGH PERMEABILITY AREA
LOW PERMEABILITY AREA
240
160
80
278
556
834
SCALE IN FEET
HIRAM 15
FANNY 6
HICKMAN 3
GALE 14 W.I.
GALE 13
HICKMAN 8
GALE 11 W.I.
GALE 16
HICKMAN 6
GALE 12
GALE 10 W.I.
GALE 15
O'DELL 1
PAPPIN 14 W.I.
PAPPIN 13W.I.
PAPPIN 12W.I.
PAPPIN 11W.I.
PAPPIN 10X
SKELLY-BARBER 10
PAPPIN 15
PAPPIN 14
PAPPIN 16
ROACH 13 W.I.
ROACH 14W.I.
ROACH 15 W.I.
ROACH 16W.I.
APPROXIMATE OFFSHORE LIMIT OF GROSS PAY SAND DEVELOPMENT
APPROXIMATE INSHORE LIMIT OF GROSS PAY SAND DEVELOPMENT
INDEX MAP
0 1 2
MILES
R 6 E
LEGEND
PRODUCING WELL
WATER INJECTION WELL
SALT WATER DISPOSAL WELL
AREA OF DIAGRAM
T 27 N
Brenner
Big Eagle
Art
Hiram
Fanny
Hickman
Gale
O'Dell
Pappin
Skelly-Barber
Harry
Roach
NORTH BURBANK UNIT
PHILLIPS (Oper)
SOUTH STANLEY W.F.
KEWANEE (Oper)

acoustic, density, and various lateral devices. The logs are hung on a common datum, which allows subsurface structures to be visualized. The SP and velocity surveys are used in combination to delineate zonation within the sands. The panel diagrams show the sand development to be essentially continuous through the pay interval. In general, the upper zone shows maximum SP deflection and maximum porosity/permeability development. The rapid decrease in porosity development from forebar to backbar is exemplified by wells on the Big Eagle and Art leases (Fig. 2).

Analysis of a series of cores from the North Stanley Stringer demonstrates the significant horizontal and vertical heterogeneity of the reservoir. Eleven cores, representing approximately 500 feet, show an arithmetic mean permeability of 307 md. The geometric mean of all permeability measurements is 54 md. The spatial distribution of the permeability characteristics in the reservoir contributes significantly to fluid distributions and reservoir performance. Log and core data reveal two distinct segments of high permeability, one associated with each of the two upper sand zones. Figure 4 shows the areal distribution of these high-permeability segments. A section of high permeability was encountered in the uppermost zone in most of the wells on the east side of the field. High permeability within the middle zone is limited to a small area in the northern part of the field whose axis is coincident with the axis of maximum initial daily yield (Fig. 5). The general decrease in permeability and productive capacity of wells on the west side of the field is reflected in Figs. 4 and 5.

The lower zone has low permeabilities throughout the field. None of the logs examined showed porosity development in this zone approaching that of the upper zones, and analyses of cores from the lower zone generally show low porosities and permeabilities.

On the basis of permeability characteristics, the reservoir can be divided into three areas, shown in Fig. 4 and summarized below.



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PERMEABILITY VARIATIONS THROUGH BURBANK SAND INTERVAL

FIGURE 4

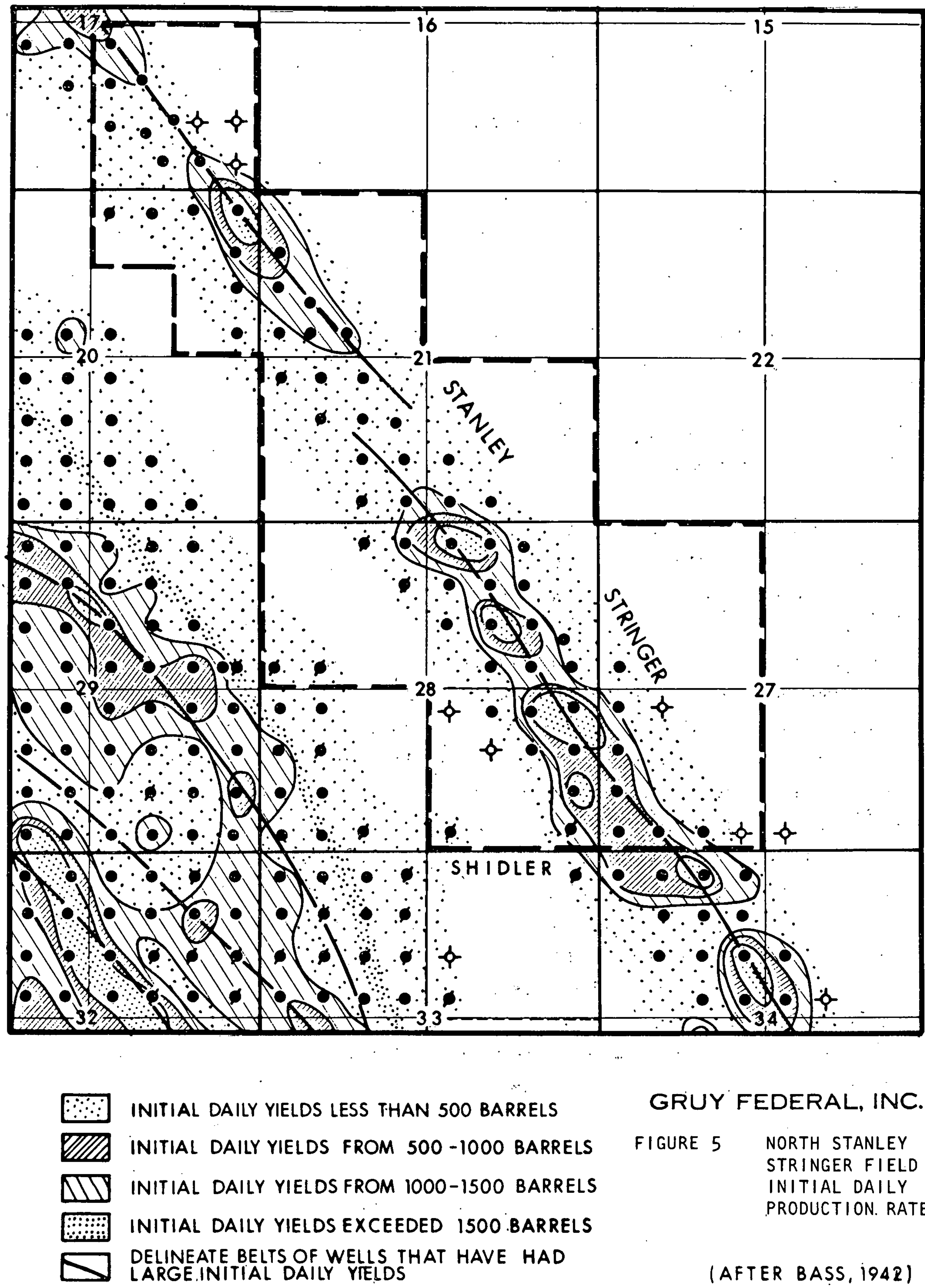

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FIGURE 5 NORTH STANLEY STRINGER FIELD INITIAL DAILY PRODUCTION RATES.

(AFTER BASS, 1942)

	Permeability Characteristics by Zone			Area Composite	
	Upper Zone	Middle Zone	Lower Zone	Arithmetic Mean	Permeability Variation*
Area 1	High	High	Low	419 md	0.86 - 0.91
Area 2	High	Low	Low	360 md	0.85 - 0.90
Area 3	Low	Low	Low	54	0.60 - 0.80

*Higher values associated with net pay cutoff at 1.0 md; lower values with cutoff at 10 md.

Figure 4 also shows graphically a composite permeability distribution curve for each of these three areas.

Plots of statistical permeability distribution for each of the above zone segments and for the total composite reservoir are shown in Figs. 6-11. Table 1 summarizes data obtained from these plots.

Also shown in Table 1 are core-derived residual oil saturation data for each zone segment. Porosity/permeability plots for each zone segment are shown in Figs. 12-16. Figures 12 and 13 show porosity/permeability relationships for the regions of high permeability in the upper and middle zones, respectively. The plots are similar and indicative of high-energy environments, with limited accumulation of clay-sized particles. In contrast, plots of the low-permeability regions in the upper and middle zones (Figs. 14 and 15), show porosity/permeability relationships shifted toward lower porosities, indicating tight sands. This lack of porosity and permeability may be the result of a lower-energy environment and an increase in clay-sized particles, which causes a decrease in pore space. Alternatively, post-depositional mineralization through action of ground water or percolation of overlying waters may be the primary factor in the decreased porosity/permeability in the southwest section of the field.

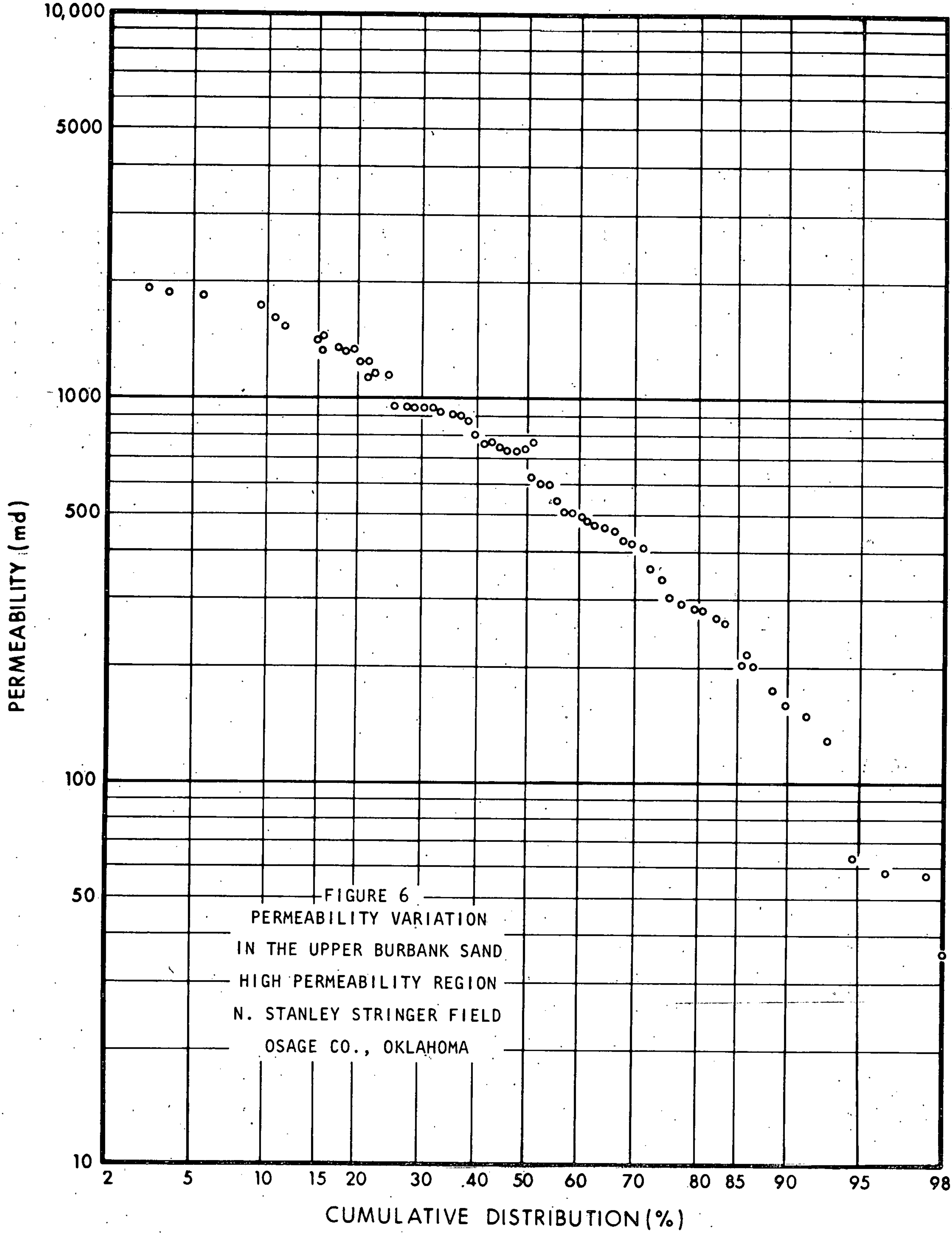
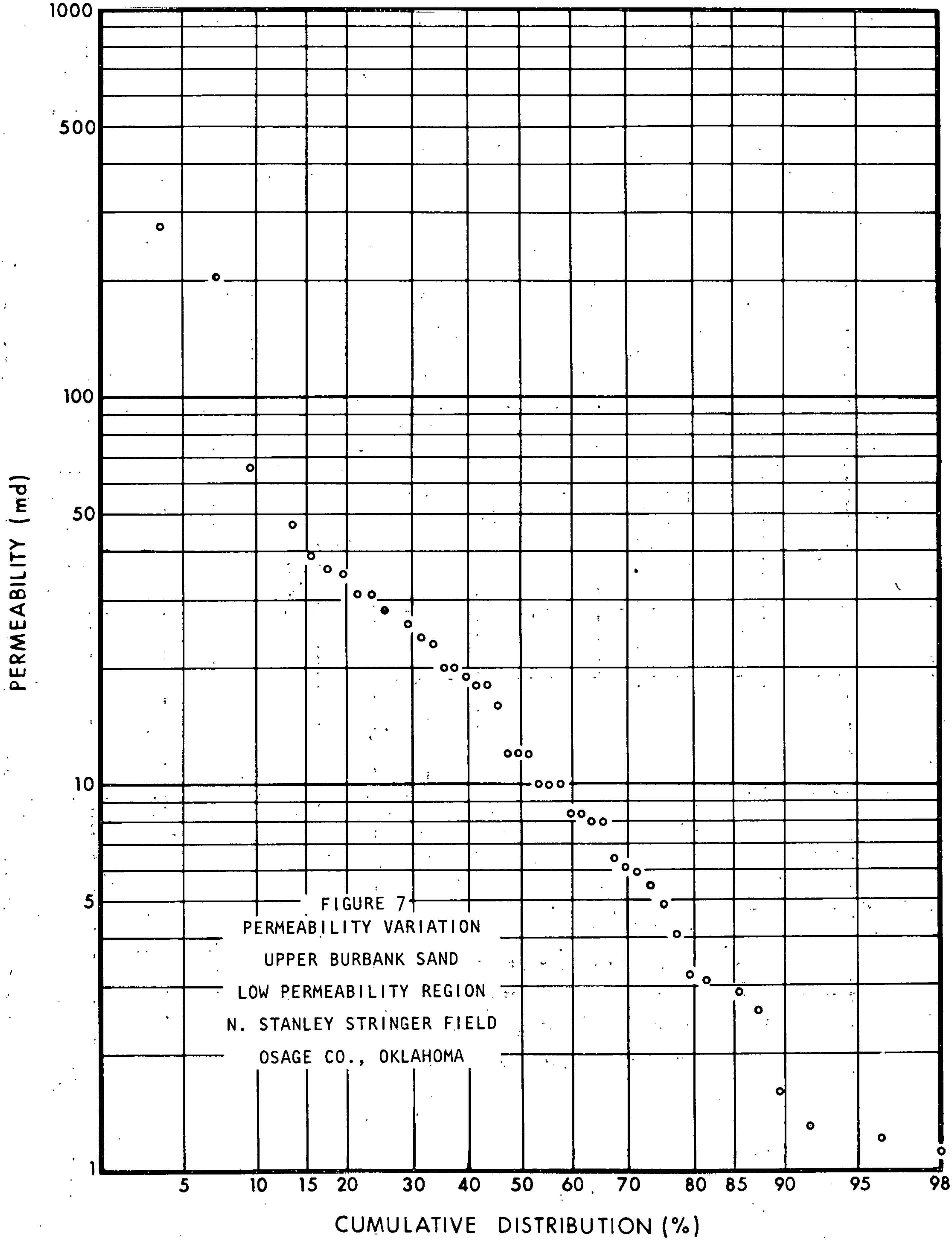


FIGURE 6
PERMEABILITY VARIATION
IN THE UPPER BURBANK SAND
HIGH PERMEABILITY REGION
N. STANLEY STRINGER FIELD
OSAGE CO., OKLAHOMA


1000
500
100
50
10
5
1
PERMEABILITY (md)
5
10
15
20
30
40
50
60
70
80
85
90
95
98
CUMULATIVE DISTRIBUTION (%)
FIGURE 7
PERMEABILITY VARIATION
UPPER BURBANK SAND
LOW PERMEABILITY REGION
N. STANLEY STRINGER FIELD
OSAGE CO., OKLAHOMA

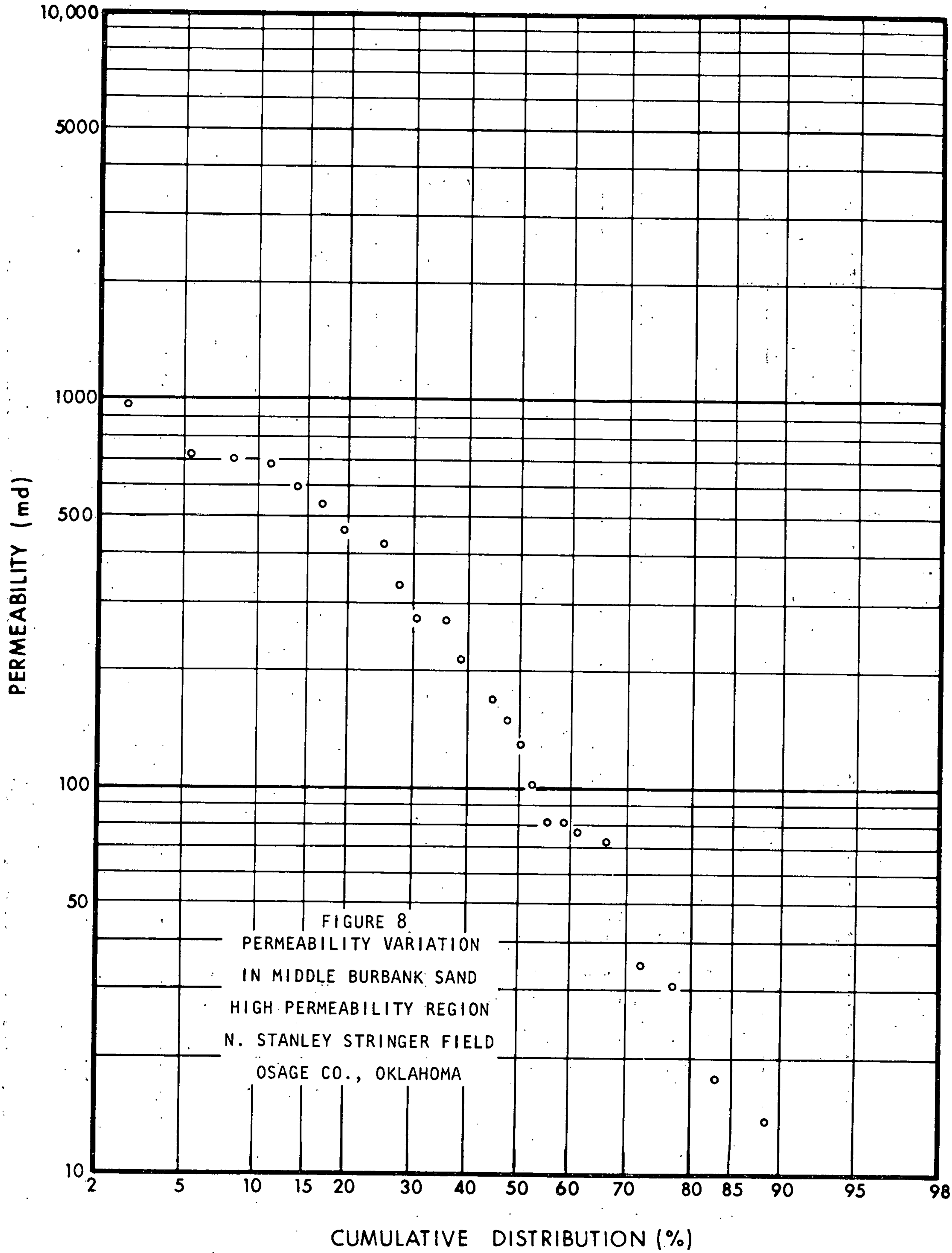


FIGURE 8
PERMEABILITY VARIATION
IN MIDDLE BURBANK SAND
HIGH PERMEABILITY REGION
N. STANLEY STRINGER FIELD
OSAGE CO., OKLAHOMA

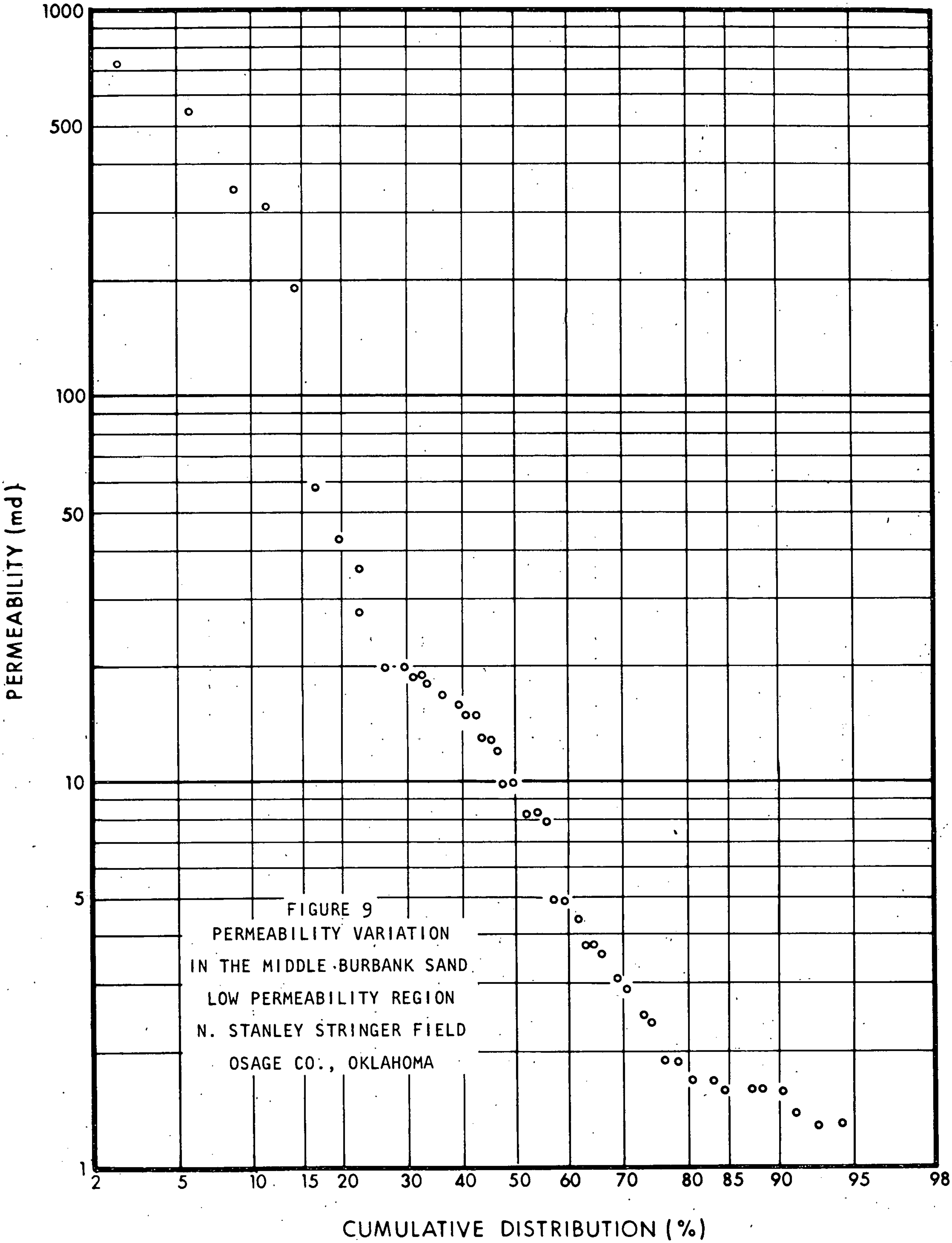


FIGURE 9
PERMEABILITY VARIATION
IN THE MIDDLE BURBANK SAND
LOW PERMEABILITY REGION
N. STANLEY STRINGER FIELD
OSAGE CO., OKLAHOMA

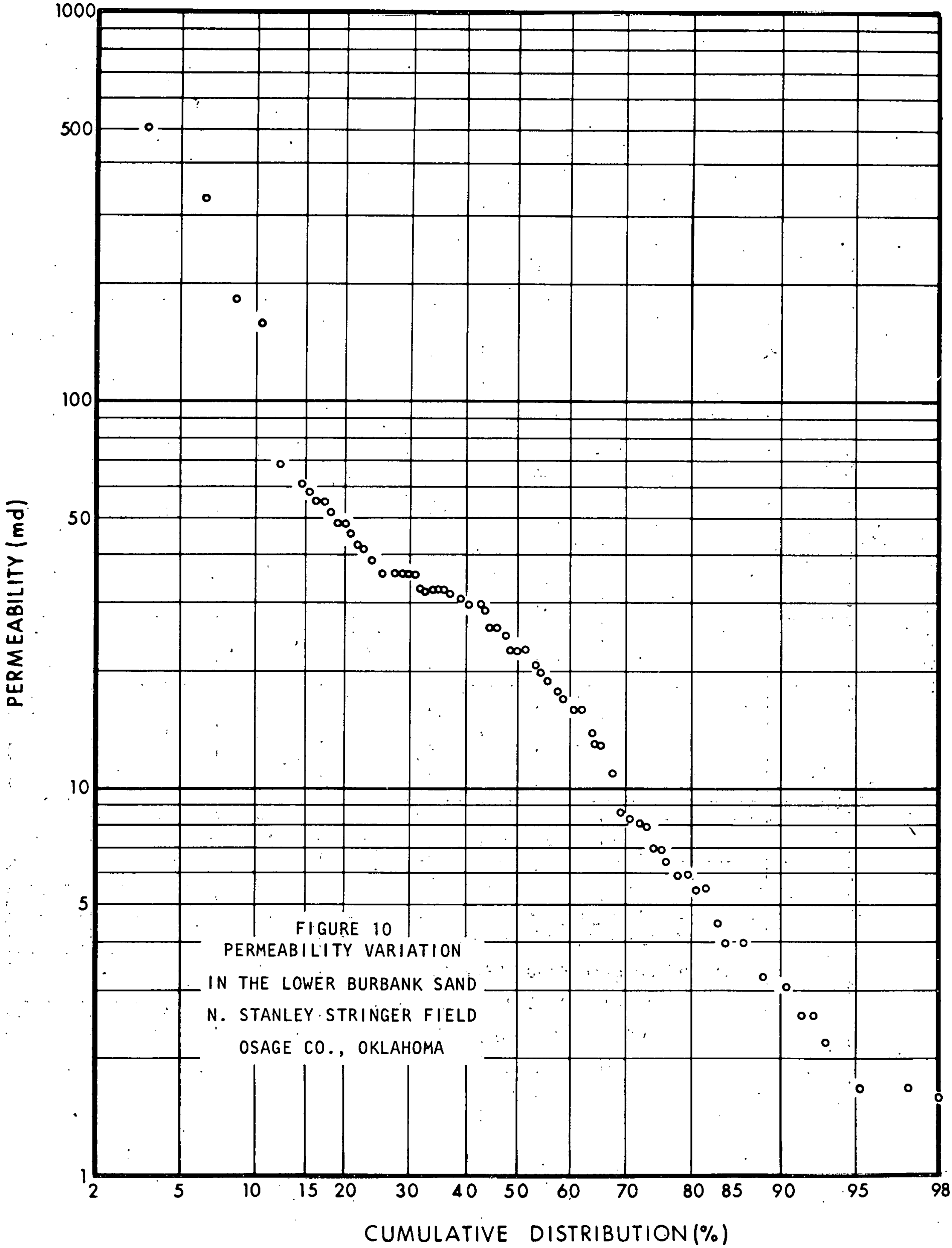


FIGURE 10
PERMEABILITY VARIATION
IN THE LOWER BURBANK SAND
N. STANLEY STRINGER FIELD
OSAGE CO., OKLAHOMA

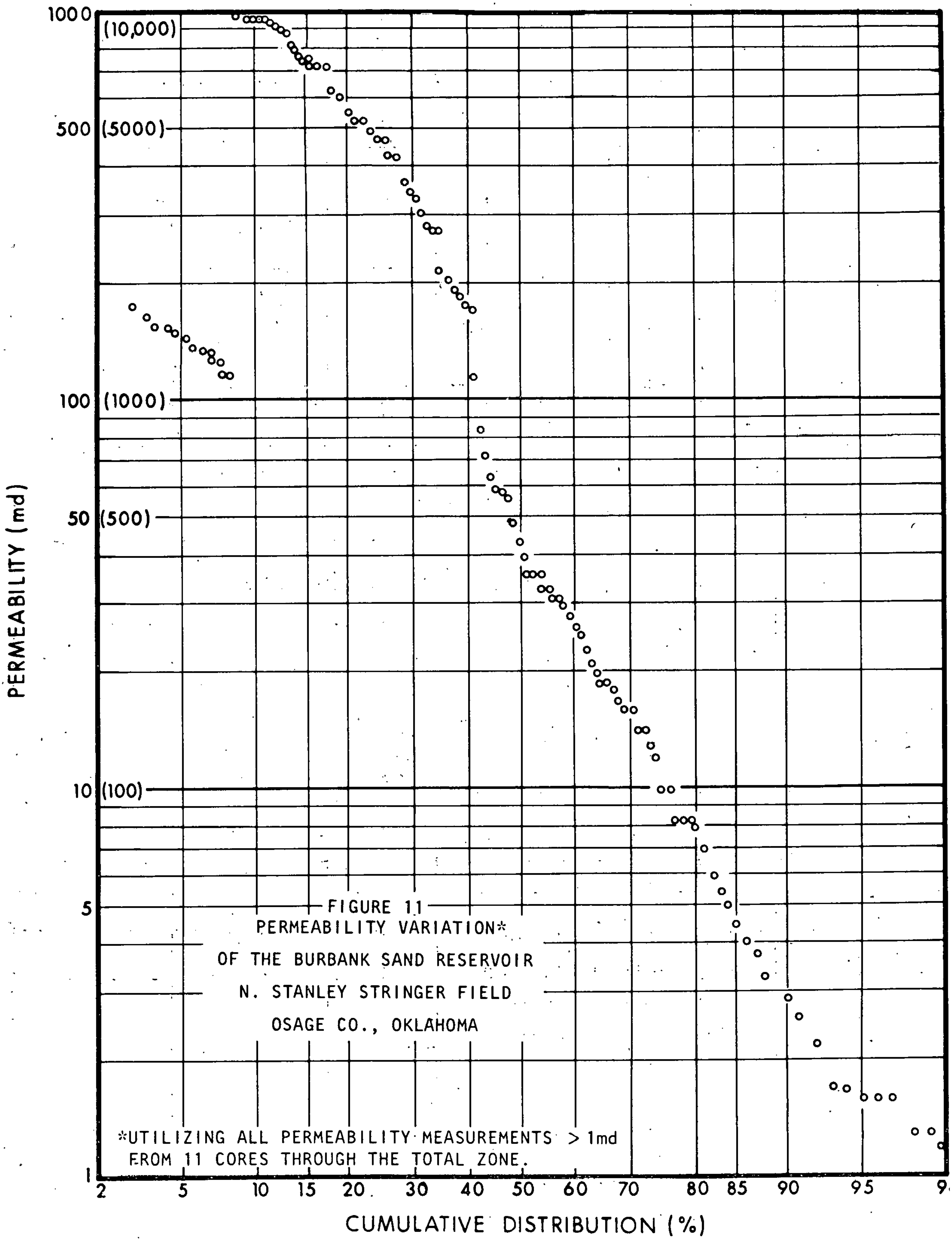


FIGURE 11
PERMEABILITY VARIATION*
OF THE BURBANK SAND RESERVOIR
N. STANLEY STRINGER FIELD
OSAGE CO., OKLAHOMA

TABLE 1

PERMEABILITY AND RESIDUAL OIL SATURATION DATA
BURBANK SANDS, NORTH STANLEY STRINGER FIELD

Permeability Variations

	REGION OF HIGH PERMEABILITY			REGION OF LOW PERMEABILITY		
	Permeability Variation	Arithmetic Mean (md)	Geometric Mean (md)	Permeability Variation (1)	Arithmetic Mean (md)	Geometric Mean (md)
Upper zone	0.6	774	544	0.5-0.7	33	12
Middle zone	0.8	231	104	0.6-0.9	71	11
Lower zone	-	-	-	0.5-0.7	54	19

Total reservoir: variance 0.8-0.9; arithmetic mean 307 md; geometric mean 57 md.

(1) Higher values associated with net pay cutoff at 1.0 md; lower values, cutoff at 10 md.

Core Residual Oil Saturations

	REGION OF HIGH PERMEABILITY		REGION OF LOW PERMEABILITY	
	No. of Readings	Arithmetic Mean (%)	No. of Readings	Arithmetic Mean (%)
Upper zone	82	18.41	51	30.74
Middle zone	25	23.92	68	31.54
Lower zone	-	-	73	28.80

Total reservoir: 299 samples, arithmetic mean 26.5

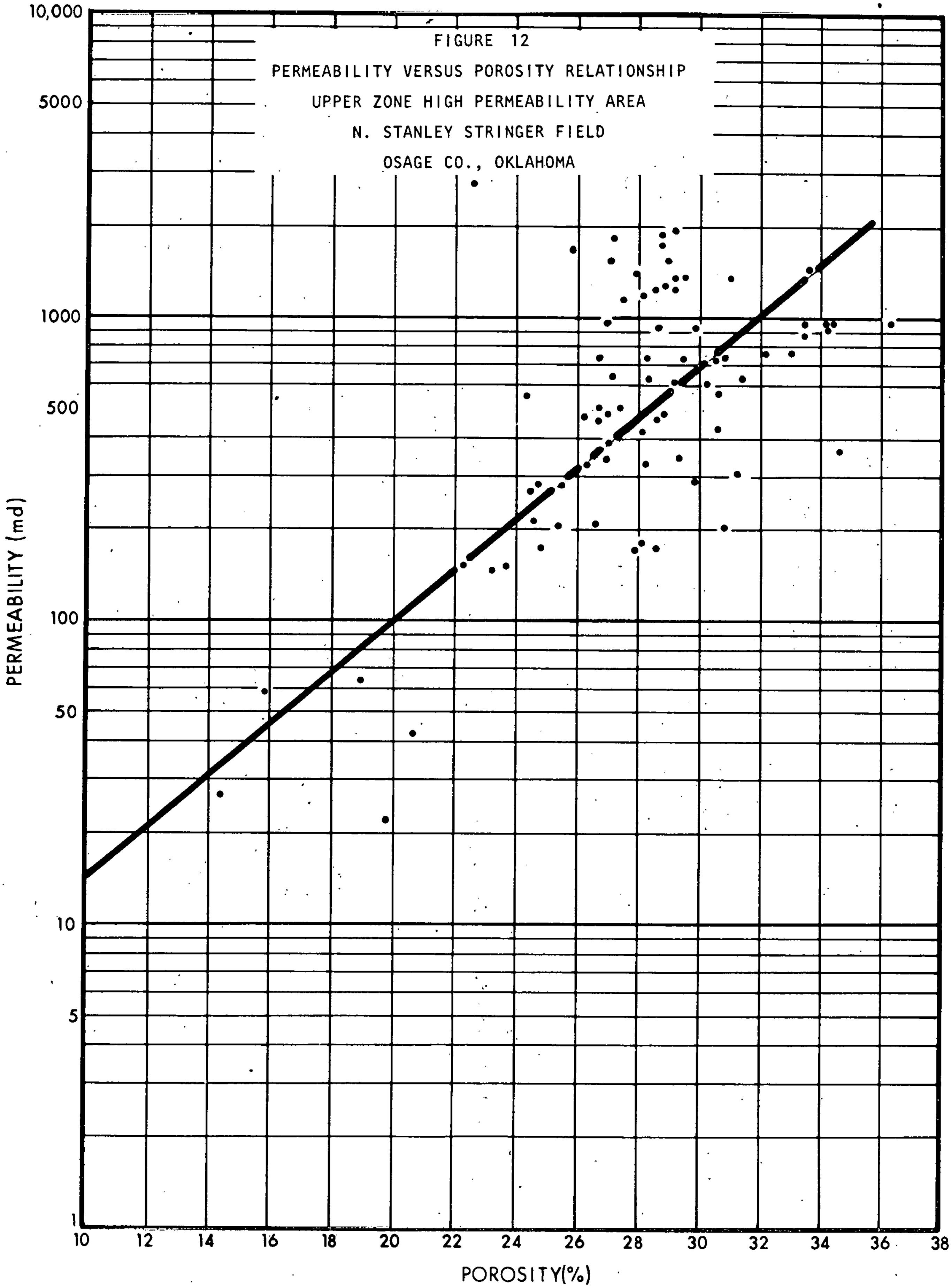


FIGURE 12
PERMEABILITY VERSUS POROSITY RELATIONSHIP
UPPER ZONE HIGH PERMEABILITY AREA
N. STANLEY STRINGER FIELD
OSAGE CO., OKLAHOMA
10,000
5000
1000
500
100
50
10
5
1
PERMEABILITY (md)
10
12
14
16
18
20
22
24
26
28
30
32
34
36
38
POROSITY(%)

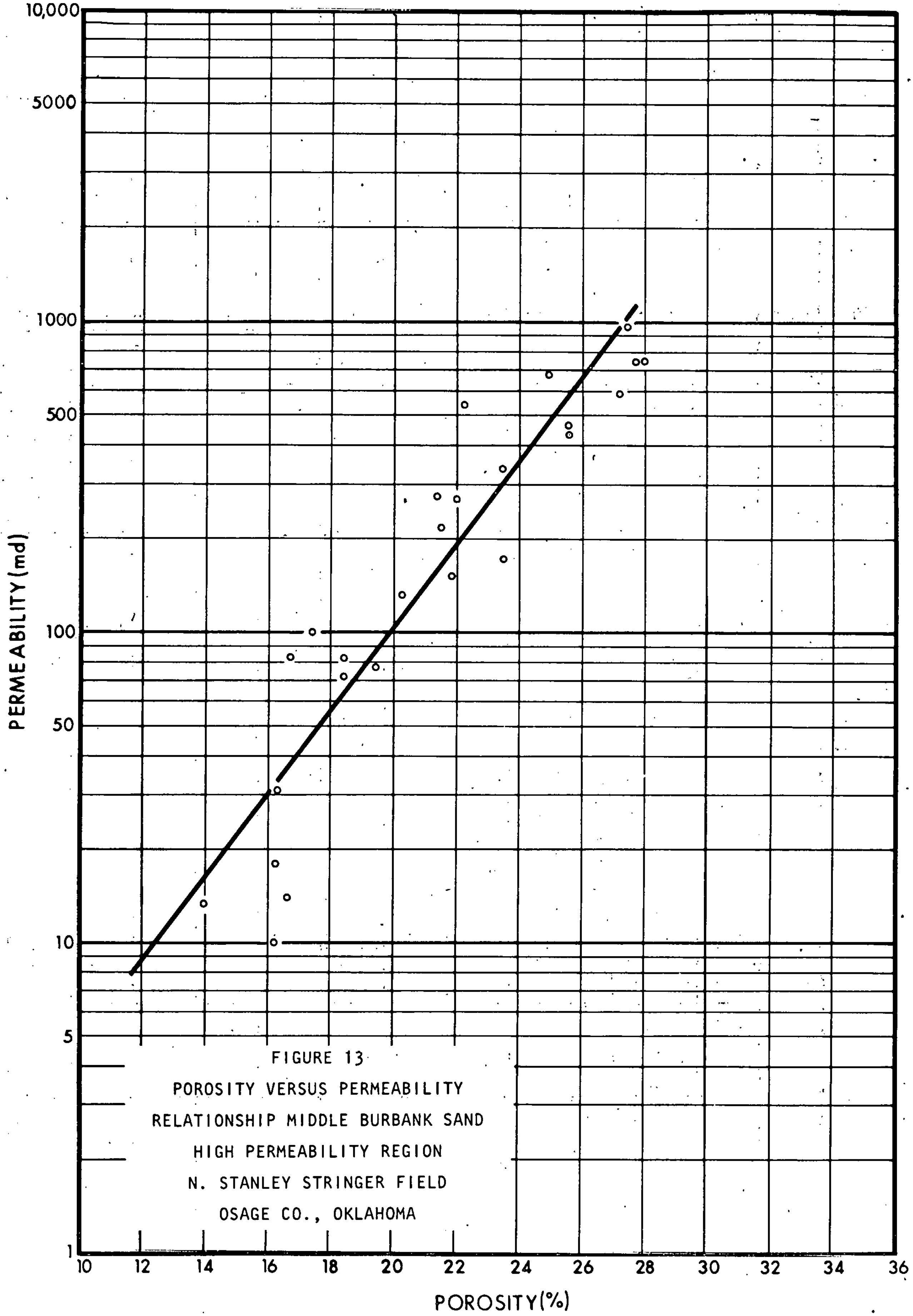


FIGURE 13
POROSITY VERSUS PERMEABILITY
RELATIONSHIP MIDDLE BURBANK SAND
HIGH PERMEABILITY REGION
N. STANLEY STRINGER FIELD
OSAGE CO., OKLAHOMA

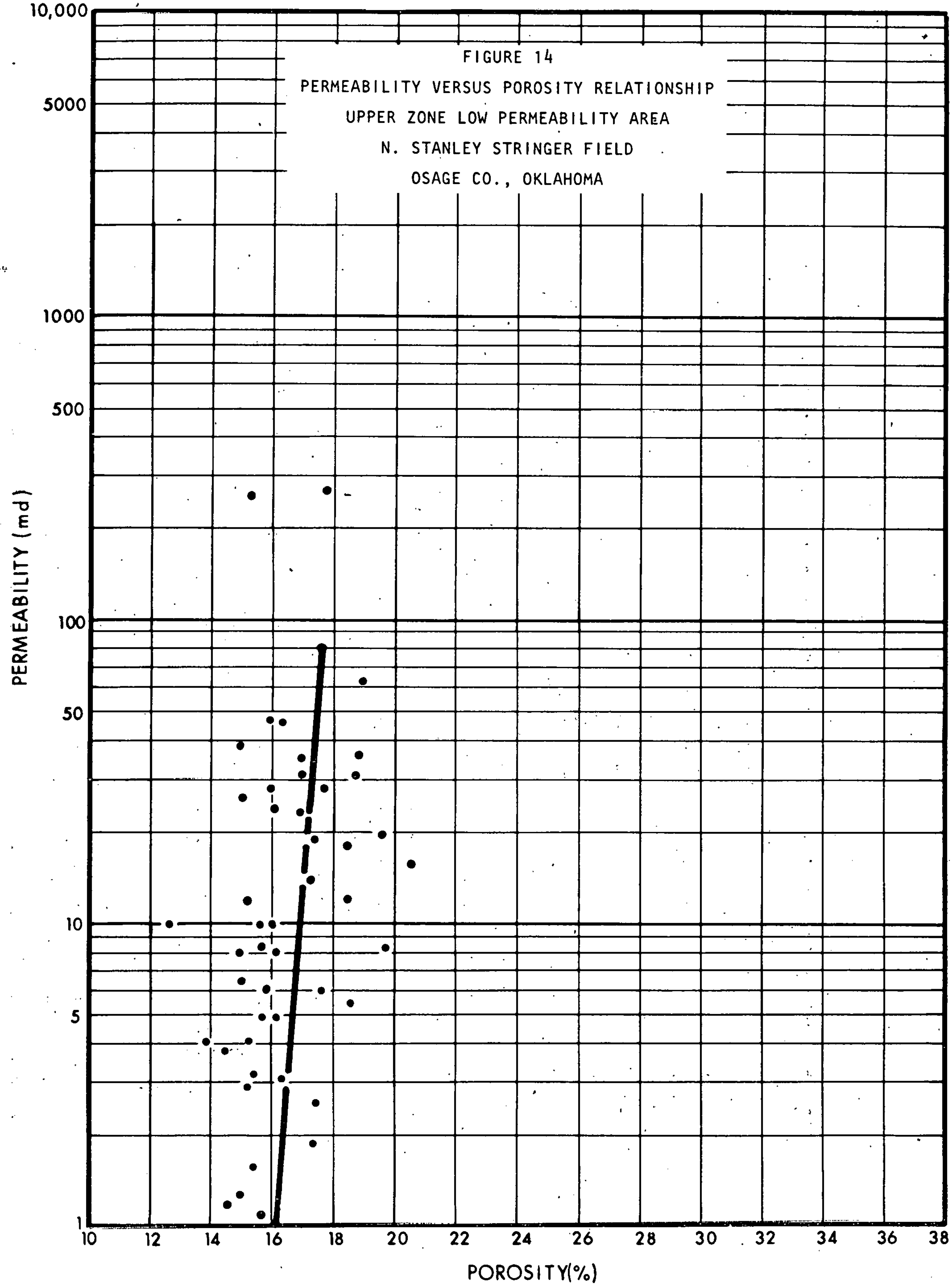


FIGURE 14
PERMEABILITY VERSUS POROSITY RELATIONSHIP
UPPER ZONE LOW PERMEABILITY AREA
N. STANLEY STRINGER FIELD
OSAGE CO., OKLAHOMA
PERMEABILITY (md)
10,000
5000
1000
500
100
50
10
5
1
10
12
14
16
18
20
22
24
26
28
30
32
34
36
38
POROSITY(%)

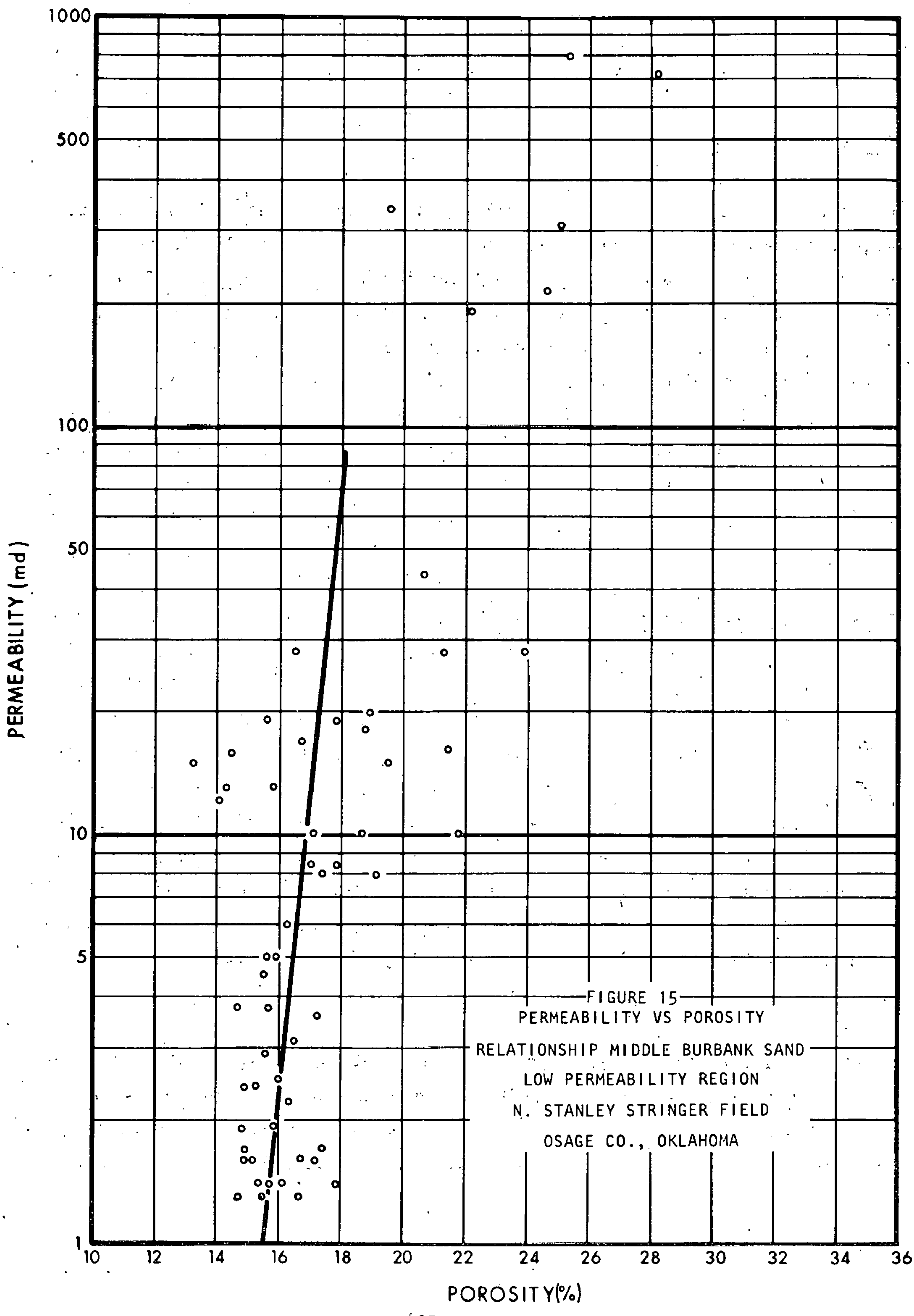


FIGURE 15
PERMEABILITY VS POROSITY
RELATIONSHIP MIDDLE BURBANK SAND
LOW PERMEABILITY REGION
N. STANLEY STRINGER FIELD
OSAGE CO., OKLAHOMA

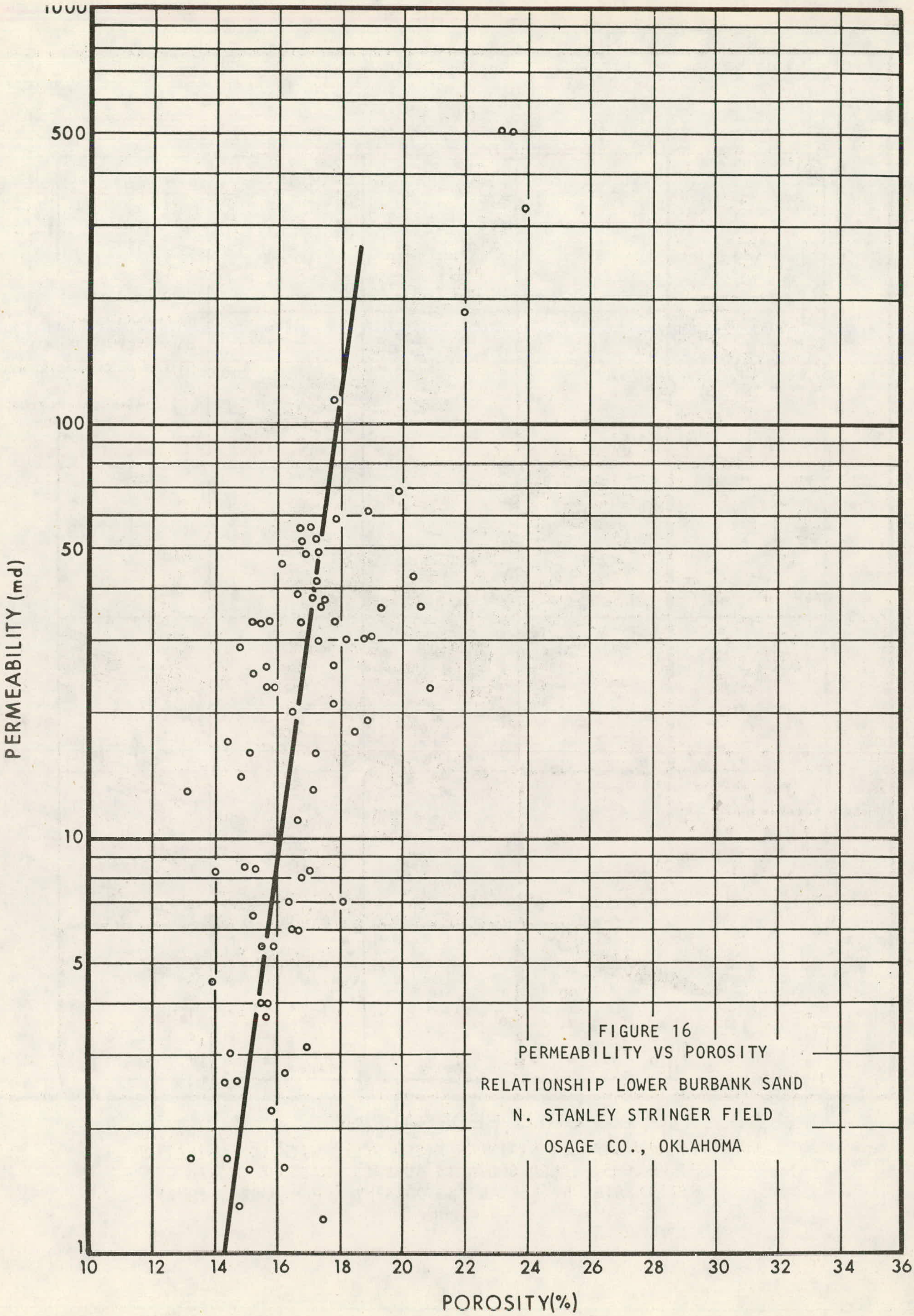
Figure 16 is a plot of porosity/permeability for the lower zone, which is similar to the low-permeability regions of the two upper zones.

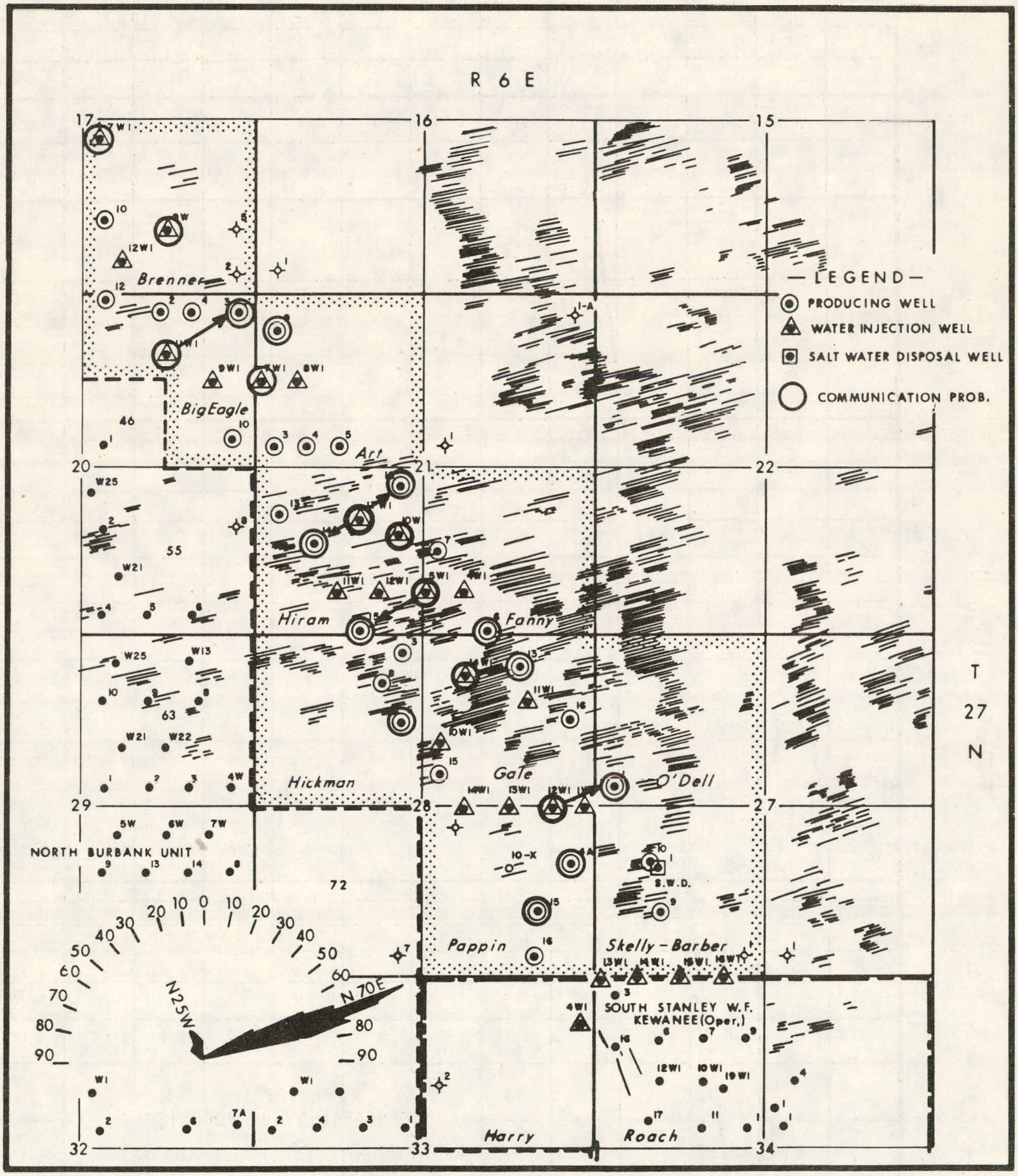
Fracture Systems.

Evidence for communication between wells existed before the polymer-augmented waterflood program was begun. In the initial stages of the program, tracer studies showed communication between Big Eagle 2 and Big Eagle 3, and communication between several other wells was suspected. As the program progressed, communication between Hiram 14, 17, and 16 was established, as well as between other pairs of wells, including Hiram 15 and Fanny 5, Gale 14 and 13, and Pappin 12 and O'Dell 1. In each case, the communication involved fluid movement in a northeast-southwest direction, normal to the axis of the field. Similar conditions existed in the Burbank Field, but communication was also occasionally northwest-southeast (Hagen, 1972).

Hagen (1972) conducted a study of jointing in surface rocks using aerial photography and field mapping. The project, centered on the Burbank Field, analyzed the waterflood project at Burbank in light of fracture patterns revealed on the surface and suspected to be present at reservoir depths. A system of parallel joints, principally oriented at N70°E, is present in the area studied, which included the North Stanley Stringer. Figure 17 shows the surface fracture pattern mapped by Hagen in the North Stanley Field, along with those wells having communication problems. The orientation of surface fractures corresponds quite closely to the known directions of communication. Problems have included early breakthrough of injected fluids in producing wells and abnormally high injection rates in injection wells.

Hagen was unable to determine whether the joints have dip, and no specific correlation between surface jointing and communication between wells is seen in Fig. 17. It does seem certain, however, that the communication problems experienced in the reservoir result largely from a fracture


1000
500
100
50
10
5
1
PERMEABILITY (md)
10
12
14
16
18
20
22
24
26
28
30
32
34
36
POROSITY(%)
FIGURE 16
PERMEABILITY VS POROSITY
RELATIONSHIP LOWER BURBANK SAND
N. STANLEY STRINGER FIELD
OSAGE CO., OKLAHOMA



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NORTH STANLEY STRINGER FIELD WELLS WITH COMMUNICATION PROBLEMS. ALSO SHOWN IS SURFACE FRACTURE SYSTEM DELINEATED BY AERIAL PHOTOGRAPHY (FROM HAGEN, 1972).

FIGURE 17

system having surface expression. Furthermore, joints in the incipient fracture system can be opened under relatively low pressures. Phillips Petroleum Company (1976) conducted pressure parting tests in the Burbank Field and found formation breakdown at a bottomhole pressure of 1465 psi at a rate of 340 BWPD. This corresponds to a fracturing pressure depth gradient of 0.5 psi per foot of overburden, lower than the "normal" value (0.75 psi per foot) for sandstone reservoirs.

The fracture system can have significant areal continuity, as shown by Hunter (1966), who found evidence of water encroachment from the Burbank Field to the Stanley Stringer Field and concluded that a fracture system in the shale section immediately above the Burbank sand was the water loss zone, since the Burbank sand was missing in the interval between the two fields.

The exact mechanism of origin of the jointing system associated with the North Stanley Stringer Field is unknown. Joint systems are commonly considered to be shear or tension fractures, with regional forces of compression, tension, or torsion the primary generating mechanisms.

Injectivity profiles run in all of the injection wells further emphasize the complexity of the reservoir. Observed patterns included injection exclusively into either the upper or lower portions of the sand as well as distribution in varying degrees between the two. As noted in Kewanee's 1978 report, injection into the formation did not correlate with high permeability in the sands; in some cases the injected fluid bypassed pay sections having permeabilities greater than 1000 md. Apparently the fracture system determines the pattern of fluid acceptance, at least in the vicinity of the wellbore. On the other hand, Kewanee found that wells with high permeabilities also had the highest injection rates. It would appear that the upper, high-permeability zones are the primary paths of fluid travel. Since high permeabilities occur only in the upper zones of the sand, while injectivity profiles indicate significant fluid input into the lower zone, fluids leaving the wellbore through fractures in the lower zone must migrate to the upper zone at some distance from the wellbore.

Of the 10 core analyses that included core descriptions, 7 showed vertical fractures either in the reservoir rocks or in the shales immediately above or below them, suggesting that the reservoir is highly fractured.

Review of the Polymer Injection Program in the Stanley Stringer Field

Historical Summary.

The Stanley Stringer Field was originally developed in 1926 on a fairly uniform 10-acre spacing pattern. Figure 5 shows the location of the 64 original producers in the 1010-productive-acre project area and the distribution of initial well productivities. In the project area, further primary development added 11 producers around the periphery of the field; about 20 additional wells were drilled as replacements for mechanical failures or as new injection wells to adapt the waterflood injection pattern to the orientation of the natural fracture system. About 50 wells were abandoned before the polymer project began, most of them probably because of high water-oil ratios.

Waterflooding was initiated in 1959 after depletion by primary methods and some gas injection and vacuum operations. Recovery by these methods from the project area was 10.7 million barrels. Additional recovery resulting from waterflooding before the polymer project was initiated in 1975 was 4.3 million barrels, at which time the producing water-oil ratio was approximately 63 barrels of water per barrel of oil produced. Table 2 provides information on reservoir characteristics and production history.

The injector-producer pattern used for the polymer injection project resulted from the use of existing waterflood injectors together with those remaining production wells. The distribution of injection wells was intended to approximate a line drive pattern oriented for maximum flow potential in a direction normal to the orientation of the existing fracture system. However, considering the flow capacity of the high-permeability portions of Zones 1 and 2, the apparent ease of access to these zones by

TABLE 2

NORTH STANLEY PROJECT RESERVOIR AND PERFORMANCE SUMMARY

		Note
Project size, acres	1024	1
Average pay thickness, feet	47	1
Reservoir pay volume, acre-feet	48,128	
Average porosity, percent	18	2,3
Average permeability, md	300	2,3
Initial formation volume factor, vol/vol	1.18	2
Formation volume factor at start of waterflood	1.05	1
Reservoir temperature (T_R), °F	105	1
Oil viscosity at T_R, cp	2.36	1
Water viscosity at T_R, cp	0.63	1
Average connate water saturation, fraction P.V.	0.30	2,3
Average irreducible residual oil saturation, fraction P.V.	0.30-0.33	5;1,4
Aggregate permeability variation	0.8-0.9	6
Mobility ratio	1:1	4

	Stock tank bbl, thousands	
Original oil in place		39,900
Primary ultimate (note 7)		10,700
Waterflood recovery:		
Cumulative to Jan. 1, 1975	4,300	
Estimated waterflood reserves, Jan. 1, 1975	700	
Estimated waterflood ultimate		5,000
Production Jan. 1, 1975-Jan. 1, 1979	860	
Estimated reserves Jan. 1, 1979	340	
Estimated ultimate after Jan. 1, 1975	1,200	
Estimated total waterflood plus project incremental		5,500
Estimated incremental due to project		500

NOTES:

1. Derived from data used in reservoir simulation model; see Table 3.
2. Reported by Kewanee.
3. Confirmed by Gruy study.
4. Based on two core flood tests.
5. Gruy estimate based on composite core data.
6. 0.8 at 10-md cutoff or 0.9 at 1.0-md cutoff - net pay.
7. Including vacuum and gas injection operations.

injected fluids via the fracture system regardless of point of entry, and the general concentration of fluid injection in the central portions of the reservoir area, the aggregate flow pattern for injected fluid probably has assumed a geometry in the high-permeability zones more resembling a "crestal" drive, with the principal mass of injected fluids expanding irregularly outward from the central area. The coverage in these zones would be expected to be very high, approaching 100 percent, while coverage in the lower permeability zones would be less extensive and more irregular.

Preparation for Polymer Injection.

Preparations for initiation of polymer injection included:

1. Mechanical check of all production and injection well equipment; repairs and replacements as needed, including repairs of casing leaks in some wells and installation of plastic-lined tubing on packers in all injectors.

2. Well workovers, including acid treatments of five injectors.

3. Abandonment of two injection wells because of casing failures, drilling of one replacement injection well, and drilling of one new production well.

4. Development of a fresh water supply and a saltwater disposal system to permit use of fresh water pre-flush and after-flush.

5. Laboratory analyses of cores obtained from a new well, and a simulation study with performance prediction.

6. Design of the polymer injection program.

7. Performance of a mini-test of polymer characteristics under actual injection conditions.

Project Design and Evaluation.

The polymer selected for this project was a polyacrylamide of the Dow Pusher series. Early design concepts were based on use of the high molecular weight Pusher-1000 material at a concentration as high as 1000 ppm. However, practical considerations, particularly recognition of the risks of severe channeling, led to the choice of the somewhat lower molecular weight Pusher-700 and a lower starting concentration (250 ppm). Furthermore interim developments in slug design theory indicated an advantage in using a tapered main slug with a low final concentration. The selected design provided for the injection of a total of 1,250,000 pounds of polymer in stages, as follows:

Days	Concentration (ppm)	Pounds Polymer at 38,000 B/D
45	250	150,000
90	600	720,000
45	250	150,000
180	100	230,000

A simulation study was used as an aid in design and performance prediction. The model was basically a multilayered Buckley-Leverett model (without crossflow) that could accommodate multiple fluid banks. Values for basic reservoir and process parameters incorporated in the model are shown in Table 3. These were based on earlier volumetric estimates, a waterflood production history reconstructed from earlier well test data for the project area, and information from the cores obtained from the replacement injection well. The model study yielded a good fit of the stabilized water-oil ratio versus cumulative waterflood oil production characteristics over the last five years of the waterflood. A history match of the total waterflood project was not achieved, however, possibly because of difficulty in representing channeling effects in the model.

The pre-project evaluation studies predicted an incremental recovery of 900,000 barrels attributable to polymer injection over a project producing

TABLE 3

NORTH STANLEY POLYMER-AUGMENTED WATERFLOOD RESERVOIR PARAMETERS USED IN MODEL STUDY (FROM KEWANEE'S FIRST ANNUAL REPORT)

BASIC RESERVOIR DATA

Pattern area, acres	1024.0
Pattern volume, acre-feet	48128.00
Distance from injector to producer, ft	660.0
Wellbore radius, injector, ft	1.00
Wellbore radius, producer, ft	1.00
Number of segments in each layer	14
Formation volume factor	1.050
Oil viscosity, cp	2.36
Water viscosity, cp	0.63

LAYER CHARACTERISTICS

Layer	Thickness, ft	Perm., md	Porosity	So	Sw	Sg	Ads., lb/AF
1	8.00	1400.00	0.248	0.563	0.136	0.301	30.0
2	4.70	739.00	0.226	0.489	0.250	0.261	30.0
3	4.70	370.00	0.201	0.460	0.300	0.240	30.0
4	4.70	109.00	0.165	0.460	0.300	0.240	30.0
5	4.70	60.00	0.157	0.410	0.370	0.220	30.0
6	20.20	33.00	0.146	0.380	0.410	0.210	30.0

RELATIVE PERMEABILITY DATA (LAYERS 3 AND 4)(1)

Sw	Krw	So	Kro
0.0000	0.000000	0.0000	0.000001
0.3000	0.000000	0.3250	0.000001
0.4099	0.003000	0.3403	0.002300
0.4426	0.010000	0.3494	0.003800
0.4781	0.029000	0.3584	0.004600
0.5059	0.054000	0.3716	0.006700
0.5324	0.081000	0.3814	0.008600
0.5588	0.114000	0.3953	0.011000
0.5748	0.135000	0.4106	0.015000
0.5894	0.157000	0.4252	0.021000
0.6047	0.181000	0.4412	0.029000
0.6186	0.195000	0.4676	0.040000
0.6284	0.210000	0.4941	0.062000
0.6416	0.229000	0.5219	0.093000
0.6506	0.246000	0.5574	0.147000
0.6597	0.256000	0.5901	0.226000
0.6750	0.285000	0.7000	1.000000

TABLE 3 (continued)

CHEMICAL CHARACTERISTICS

Chemical No.	Conc., ppm.	Resistance Factor
1	1000.00	20.00
2	500.00	15.00
3	250.00	10.00
4	100.00	5.00

RESIDUAL RESISTANCE FACTOR = 2.0

---

(1) Modified for lower and higher irreducible water saturations in higher permeability and lower permeability layers, respectively.

life of about five years. With the benefit of hindsight, it appears that the use of a broader sampling of core and log measurements and detailed geology would have allowed a more precise model description of the reservoir to be made and possibly applied effectively in expanded project performance analysis. (Such a study, however, was beyond the scope of our contract.)

Design considerations also included provisions for the following monitoring activities:

1. Monthly producing well tests including sampling for salinity and produced polymer content.

2. Monthly injection well input test measurements using 1-1/2" orifice installations at the wellheads.

3. Some specific testing including use of tracers in special cases and a series of pressure fall-off tests in key injection wells.

Mini-Injection Test Results.

The mini-injection test was performed in the Roach 19 water injection well on an adjoining tract south of the project area. It involved the successive injection of a fresh water pre-flush, 1000 pounds of P-1000 polymer at 100 ppm, and finally a fresh water after-flush. The results of the mini-test were:

1. Injection pressure during after-flush was less than 10 percent higher than during pre-flush at the same injection rate, indicating relatively little added flow resistance due to polymer injection.

2. Samples of polymer solution recovered by swabbing following P-1000 injection showed little or no shear degradation, either in the surface facilities or in passage through casing perforations into the reservoir for a small distance from the wellbore.

3. The quality control measures adopted for maintaining integrity of the polymer solution involving (addition of chemical oxygen scavengers and biocides to the fresh water) proved effective.

4. Injection profile measurements run before and after the P-1000 injection indicated some redistribution of injected fluids at the point of entry. Before polymer injection, 100 percent of the fluid was entering the bottom 15 feet of the perforated interval. This was reduced to 79 percent, with 21 percent entering the upper 20 feet, after polymer injection.

5. No fresh water breakthrough was evident in surrounding producers after injection of 220,000 barrels of fresh water during the mini-test; thus no severe channeling problems appeared to be present, at least in the immediate vicinity of the mini-test injector. It is of interest to note that no surface evidence of fracturing was recorded by Hagen in the vicinity of this location (Fig. 17), as contrasted to the high density of fractures in most of the project area to the north.

Project Activities.

After the mini-test provided favorable results, fresh water pre-flush was commenced in February 1976 and continued until June 1976 for a total pre-flush volume of about 4 million barrels (5.8 percent PV).

Thirty days after the start of fresh water injection, salinity measurements of produced water samples indicated rapid channeling of injected water to three production wells, and, a few injection wells were taking an excessively high proportion of the total injected fluids. These observations led to a program of operations designed to achieve selective plugging of the thief zone. During the remaining period of fresh water and polymer injection, a total of 13 selective plugging treatments were performed, with varying degrees of success, on 9 injection wells. Five of the high capacity injection wells were ultimately (after completion of polymer injection) equipped with surface chokes to improve distribution of output among injection wells. One injector was shut in because of limited injectivity in November 1976, and a second in January 1978 when a casing leak developed.

Polymer injection was begun in June 1976. The original plan was followed closely, with 1,194,000 pounds of polymer injected in 11,927,000 barrels (17.5 percent PV) of solution over a period of one year.

A 3,088,000-barrel (4.8 percent PV) fresh water after-flush followed the polymer, after which injection of produced brine was resumed in October 1978.

Review of Observed Correlation Between Injection Characteristics and Production Results.

In considering North Stanley waterflooding performance, with and without polymer augmentation, it is pertinent to note that only two wells, one on the east flank (O'Dell No. 1) and one on the far northwest flank (Big Eagle No. 12) have been completed at peripheral locations with less than 40 feet pay thickness (see Fig. 18, reproduced from Kewanee final report). Incremental polymer recovery derives, in part, from improved sweep efficiency over conventional waterflooding, and hence the "boundary" effect may be a significant factor at North Stanley because of a high ratio of perimeter length to enclosed area and the probable concentration of polymer target oil in the perimeter area.

Figure 19 depicts condensed information on injection performance. Shown are the locations and types of injection well remedial operations, the overall changes in injection rates and pressures noted, and the distribution of polymer injected.

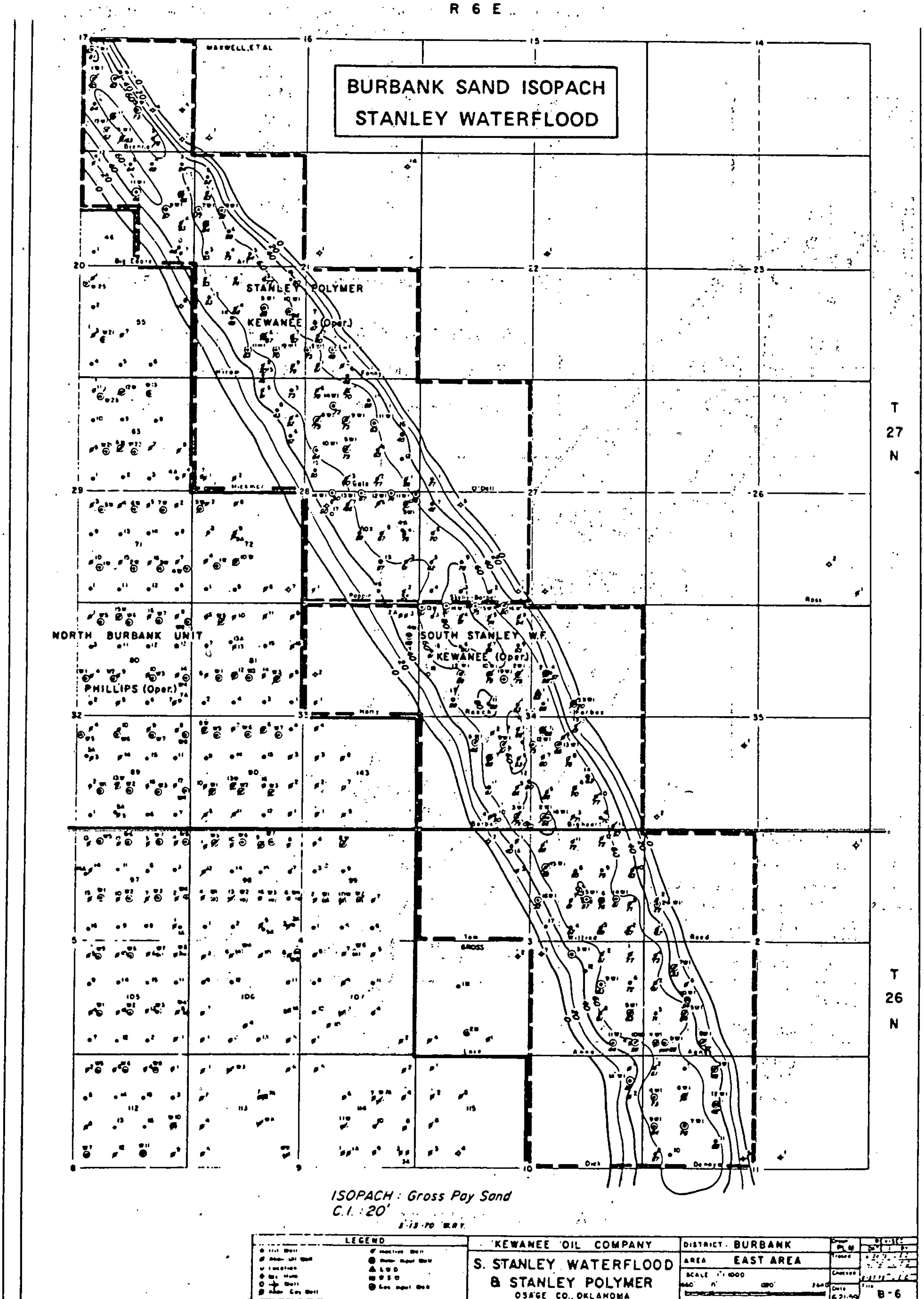

R 6 E
BURBANK SAND ISOPACH
STANLEY WATERFLOOD
STANLEY POLYMER
KEWANEE (Oper.)
SOUTH STANLEY W.F.
KEWANEE (Oper.)
NORTH BURBANK UNIT
PHILLIPS (Oper.)
T 27 N
T 26 N
ISOPACH : Gross Pay Sand
C.I. : 20'
LEGEND
KEWANEE OIL COMPANY
S. STANLEY WATERFLOOD
& STANLEY POLYMER
OSAGE CO., OKLAHOMA
DISTRICT BURBANK
AREA EAST AREA
B-6

FIGURE 18

INJECTION WELL GROUP	CHANGE IN INJECTION CONDITIONS (A)		POLYMER INJECTION THNS. LBS.	
	RATE-B/D	PRESS-PSI	TOTAL	PER WELL
△	300	110	137	45
□	(2200)	100	214	53
○	(4400)	70-380	398	66
⬡	(900)	70	272	90
◇	(2000)	(100)	172	57

(A) BASED ON MEASUREMENTS BEFORE AND AFTER POLYMER INJECTION

GROSS DISTRIBUTION OF POLYMER - THNS. LBS.

TOTAL - 11 INSIDE HI-PERM AREA - 926

TOTAL 8 - WELLS OUTSIDE HI-PERM AREA - 266

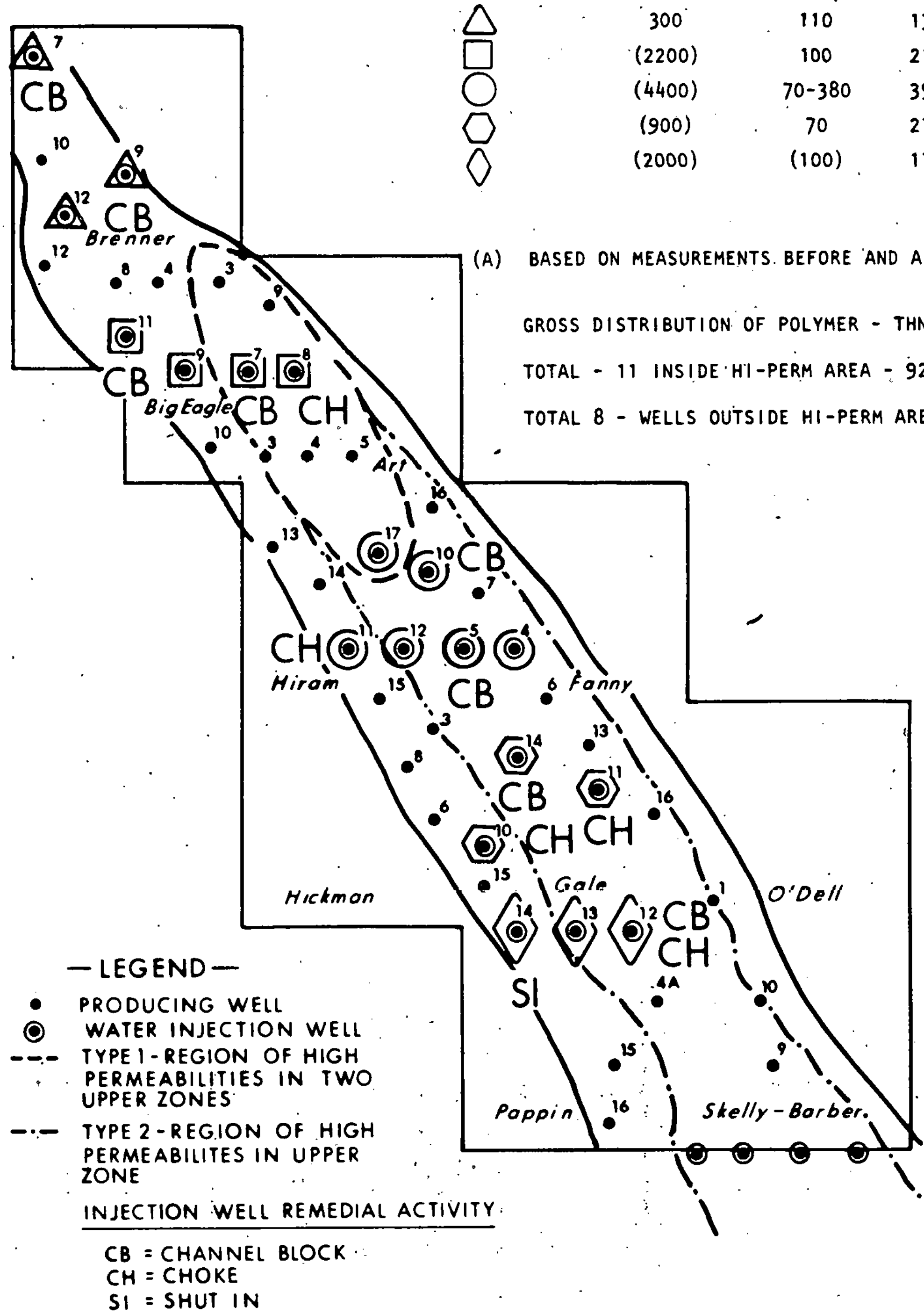


FIGURE 19

SUMMARY INJECTION DATA
NORTH STANLEY
STRINGER FIELD

The concentration of injection in the area of high permeability is apparent, as is the necessity experienced for widespread use of various techniques to combat channeling problems. It is significant that the three southernmost injectors showed an overall decrease in injection pressure, although higher pressures were achieved in all other injectors. This may relate to the poor (generally negative) response from producers in that part of the project.

The distribution of production response is shown in Fig. 20. Data in this figure are Kewanee's estimates of cumulative tertiary oil production to July 1, 1978. The principal response was concentrated in relatively few wells, with one, Fanny No. 6, yielding 36 percent of the total estimated incremental oil. It will be noted also that a loss in oil production (negative response) was experienced in the southernmost producers.

Summarized data for fresh water pre-flush and for polymer solution are shown in Table 4, where the producers are categorized by breakthrough times. These can be reduced to three broad categories: wells with channeling problems, wells with reasonably long times for polymer breakthrough, and wells where polymer solution was not seen (Fig. 21).

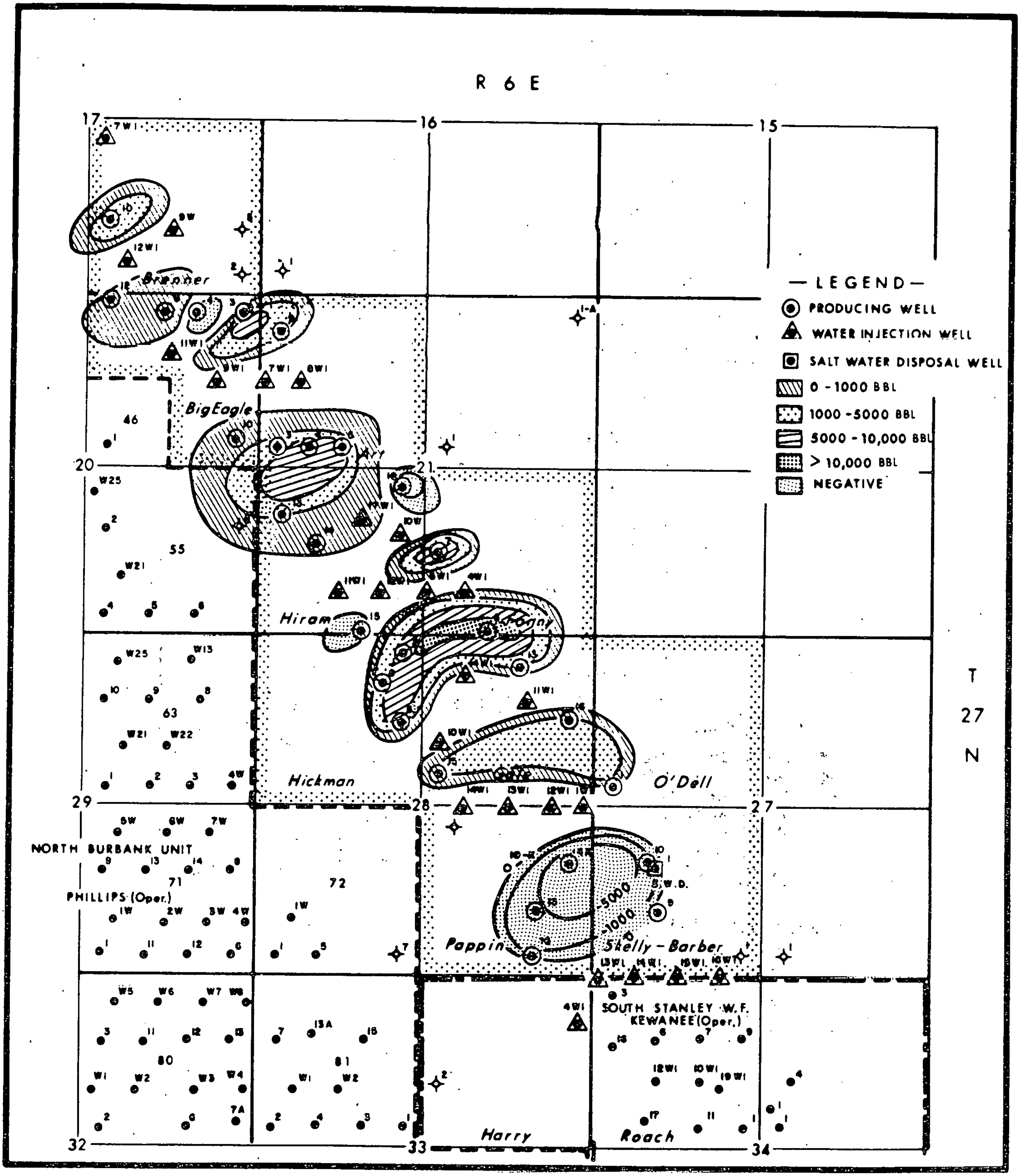
Wells with Apparent Channeling Problems.

Category A - The three producers showing the most rapid channeling of fresh water (Big Eagle 3, Hiram 15, and Gale 13) showed no apparent slowing effect due to the polymer. Little or no sustained oil production response was observed. Considering their locations relative to the areas of principal increased oil production (Fig. 20), it appears likely that channeling effects were detrimental to oil response in these wells. Each of the three was among the highest polymer producers.

TABLE 4

FRESHWATER PRE-FLUSH AND POLYMER BREAKTHROUGH TIMES

Producer Category	Number of Producers	Breakthrough time - days	
		Freshwater	Polymer
A	3	29-42	21-31
B	2	98	77-97
C	1	120	31
D-1	8	140-217	158-390
D-2	3	172-490	150-395
E	1	217	None observed
F	10	None observed	None observed



GRUY FEDERAL, INC.

TERTIARY OIL ATTRIBUTABLE TO POLYMER AUGMENT, NORTH STANLEY STRINGER FIELD.

FIGURE 20

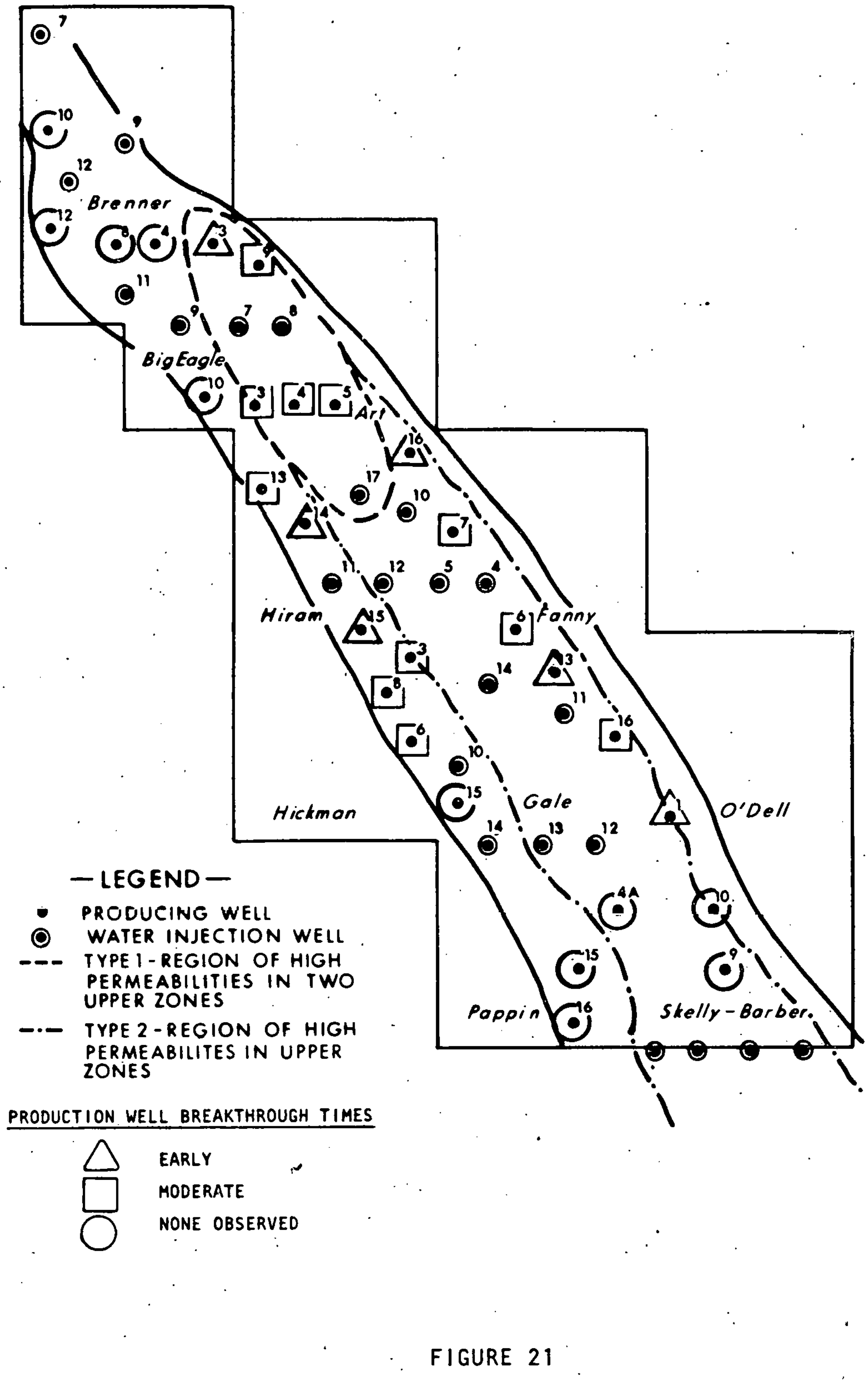


FIGURE 21

INJECTED FLUID BREAKTHROUGH TIMES
NORTH STANLEY

Category B - Two wells, Hiram 14 and 16, exhibited characteristics similar to Category A wells, except that breakthrough was not as early (less severe channeling). These wells are located on either side of Hiram 17, a particularly troublesome injector (channel blocked three times), and on a line oriented in the same direction as the observed fracture pattern. Polymer production was moderate at No. 14 (no high-permeability zone present) and moderately high at No. 16. Oil production response was nil to negative at each well.

Category C - One well, O'Dell No. 1, showed moderately early breakthrough of fresh water but very early polymer breakthrough, suggesting that channeling was aggravated after the start of polymer injection in Pappin No. 12. Surface choking was eventually necessary on this injector. Polymer production was heavy. Oil production response was nil as of June 1978, although some temporary increase was noted earlier.

Wells with Moderate Breakthrough Times.

Category D-1 - Eight wells showed moderate breakthrough times for fresh water and 10-90 percent greater breakthrough times for polymer. The relative breakthrough times for polymer solutions and fresh water suggest positive mobility control effects in the flow paths leading to these wells. Cumulative polymer production to July 1, 1978, ranged from very low to very high (200 to 19,000 pounds). One well, Gale 16, the southernmost in this category, exhibited little oil production response; the remaining seven, however, were the only ones in the project showing good sustained oil production response. These are Fanny 6, Hickman 3, 6, and 8, and Art 4, 5, and 9.

Category D-2 - Three producers, Fanny 7, Hiram 13, and Art 3, showed moderately long fresh water breakthrough time but somewhat shorter polymer breakthrough time. These results are similar, except for longer breakthrough times, to Category B wells. The grouping of these three wells and the two Category B wells around two problem injectors, Hiram 17, and

Hiram 10, suggests a degree of channeling in the vicinity of these injectors less extreme than that observed in Category A wells, but sufficient to negate most of the positive response to polymer injection. Cumulative polymer production was very small in one well (outside the high- permeability zone) and moderate in the other two. Oil production response was nil to negative.

Wells in which Polymer was Never Detected.

Category E - One well, Pappin 4-A, exhibited a moderate fresh water breakthrough time but produced no polymer in the two years following start of polymer injection. It is located in the area of reduced injection pressures in the southern portion of the project area and has shown negative oil production response.

Category F - Ten wells showed no breakthrough of either fresh water or polymer. All are located in peripheral areas of lower permeability except one, Skelly-Barber No. 9, which is located in the extreme southern portion of the project. Oil production response was either insignificant or negative.

The following observations can be made concerning the distribution of injection and production performance.

1. Channeling problems (5 production wells, 12 injection wells) appear to be randomly scattered throughout the reservoir. Producing wells with channeling problems exhibited minimal or negative production response. Nine injection wells were treated to overcome these effects.

   Polymer production averaged 15,000 pounds for wells with identifiable channeling problems and about 6700 pounds for wells where channeling was not a problem but where some polymer solution was produced.

2. Positive oil production response was obtained in areas where low-permeability zones are present and where both high-and low-permeability zones are present. In the latter case there is no positive indication that the response is attributable to either or both zones; however, the very high proportion of the total increase exhibited by Fanny 6 suggests some contribution from the high-permeability zone to this well's response. The average production increase of all producing wells with a high-permeability zone present was 8.9 BOPD, while that for all wells where no such zone is present was 2.8 BOPD. The correlation of wells with moderate breakthrough times and positive production response (compare Fig. 20 to Fig. 21) is expecially apparent.

3. Wells showing little or no response either had evidence of channeling problems or are located along the western flank of the deposit, in the areas of poorer reservoir quality.

4. The significant negative response in the southern part of the project may be related to a location outside the area bounded by polymer injectors (with possible overbalance of nonpolymer water injection in southern boundary wells) or to the reduction in injection pressures which occurred in this area, or a combination of both.

5. Injection of polymer solution was strongly influenced by the presence of a high-permeability zone. The injection wells in portions of the reservoir where a high-permeability zone was present had an average of 84,000 pounds of polymer injected, while in those wells where no such zone was present the total polymer injected averaged 33,000 pounds.

Estimate of Net Incremental Oil Recovery

The complex reservoir system, the drilling of a new production well, and the many well modifications made during the project preclude an accurate quantitative estimate of the incremental oil resulting solely from polymer injection. The following analysis attempts to evaluate the aggregate result and to make some approximations of the effects of the major contributing factors. Performance by conventional waterflooding has been projected from January 1975 for comparison with actual production from that date through December 1978, together with predicted performance to abandonment. The basis for this projection was an extrapolation of water-oil ratio versus cumulative oil production curves, taking into account established trends with and without polymer and the predicted trend of this feature from the simulation study. Figure 22 shows this analysis. It reflects our estimate of ultimate recovery of 5.5 million barrels from the polymer-augmented project, compared to 5.0 million barrels by waterflood only. The incremental recovery of 500,000 barrels attributable to the aggregate of the operations performed is about one-half the original prediction on which the project was based. This prediction appeared to be valid, judging by response observed prior to mid-1978; the necessity for revision results from the rapid decline in oil production rate (and increase in WOR) that has occurred since that time. For the purpose of this estimate a common limiting WOR of 105 has been assumed as representing the economic limit for both continued conventional flooding and flooding following the polymer slug.

Figure 23 shows the smoothed historical performance of the project, including the last three years of conventional waterflooding before preparation for polymer injection began in 1975. The decline rate of 10 percent per year without polymer injection and 17 percent per year projected after December 1, 1978, are the constant percentage decline rates which would produce the same relative ultimate recoveries predicted by Fig. 22. These are believed to be reasonable projections over the short period of time involved. Because of lower injection and total fluid production rates

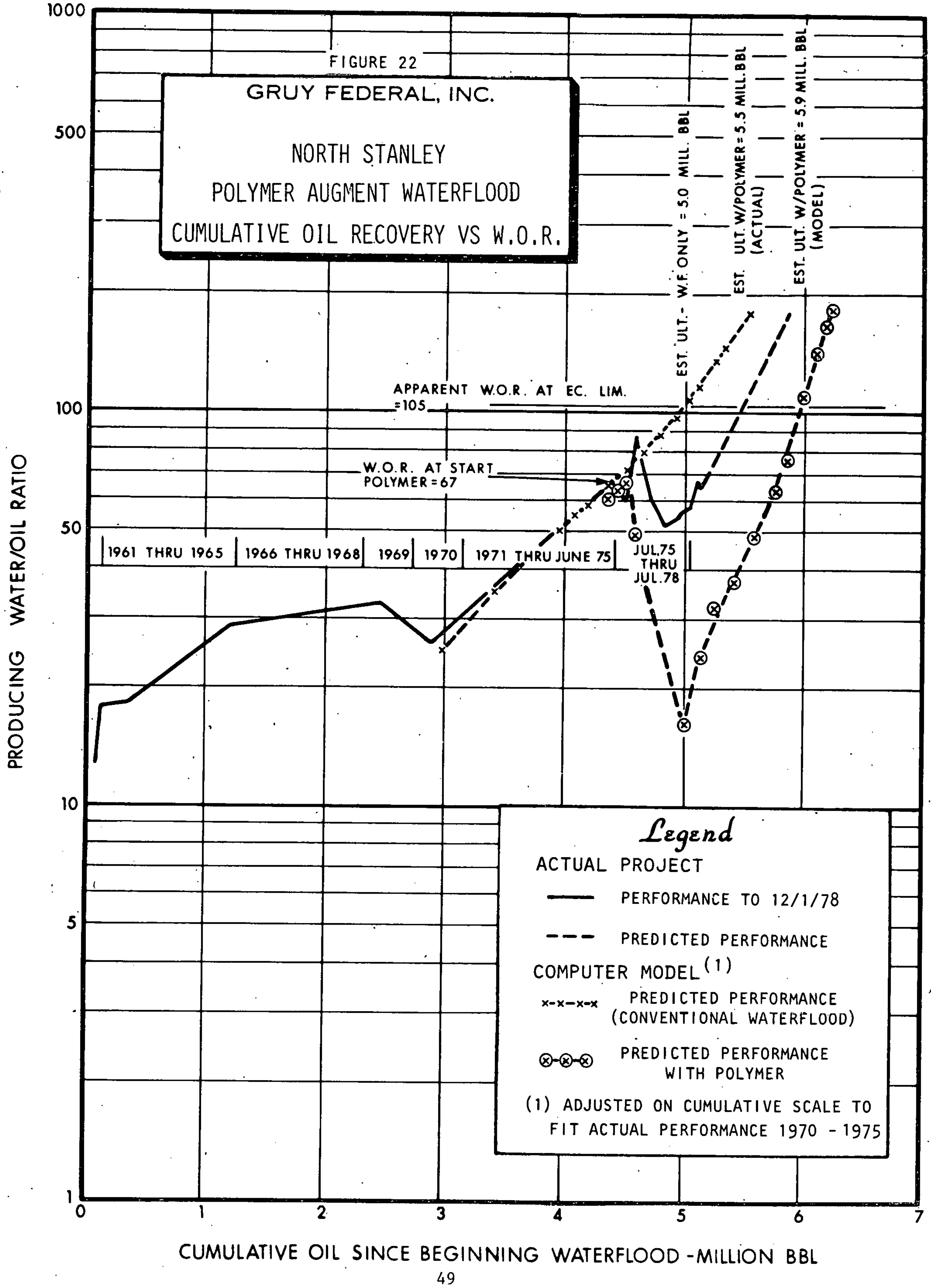


FIGURE 22
GRUY FEDERAL, INC.
NORTH STANLEY
POLYMER AUGMENT WATERFLOOD
CUMULATIVE OIL RECOVERY VS W.O.R.
EST. ULT.- W.F. ONLY = 5.0 MILL. BBL
EST. ULT. W/POLYMER = 5.5 MILL. BBL (ACTUAL)
EST. ULT. W/POLYMER = 5.9 MILL. BBL (MODEL)
APPARENT W.O.R. AT EC. LIM. =105
W.O.R. AT START POLYMER = 67
1961 THRU 1965
1966 THRU 1968
1969
1970
1971 THRU JUNE 75
JUL.75 THRU JUL.78
PRODUCING WATER/OIL RATIO
1000
500
100
50
10
5
1
0
1
2
3
4
5
6
7
CUMULATIVE OIL SINCE BEGINNING WATERFLOOD - MILLION BBL
Legend
ACTUAL PROJECT
PERFORMANCE TO 12/1/78
PREDICTED PERFORMANCE
COMPUTER MODEL (1)
PREDICTED PERFORMANCE (CONVENTIONAL WATERFLOOD)
PREDICTED PERFORMANCE WITH POLYMER
(1) ADJUSTED ON CUMULATIVE SCALE TO FIT ACTUAL PERFORMANCE 1970 - 1975

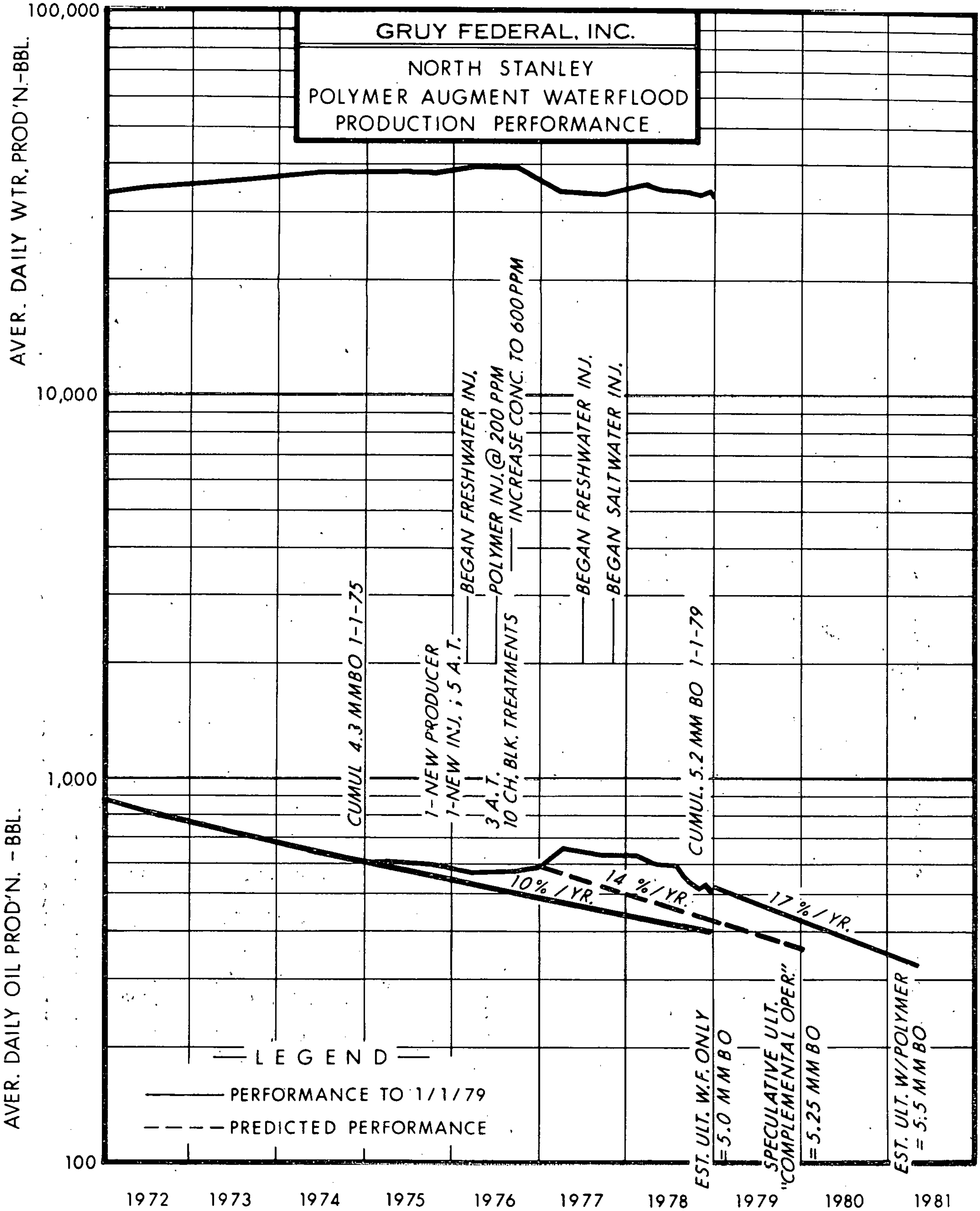

GRUY FEDERAL, INC.
NORTH STANLEY
POLYMER AUGMENT WATERFLOOD
PRODUCTION PERFORMANCE
AVER. DAILY WTR. PROD'N.-BBL.
AVER. DAILY OIL PROD'N. -BBL.
100,000
10,000
1,000
100
CUMUL 4.3 MMBO 1-1-75
1-NEW PRODUCER
1-NEW INJ.; 5 A.T.
BEGAN FRESHWATER INJ.
3 A.T.
10 CH. BLK. TREATMENTS
POLYMER INJ.@ 200 PPM
INCREASE CONC. TO 600 PPM
BEGAN FRESHWATER INJ.
BEGAN SALTWATER INJ.
CUMUL. 5.2 MM BO 1-1-79
10 % / YR.
14 % / YR.
17 % / YR.
EST. ULT. W.F. ONLY
=5.0 MM BO
SPECULATIVE ULT.
"COMPLEMENTAL OPER."
= 5.25 MM BO
EST. ULT. W/POLYMER
= 5.5 MM BO
LEGEND
PERFORMANCE TO 1/1/79
PREDICTED PERFORMANCE
1972
1973
1974
1975
1976
1977
1978
1979
1980
1981

FIGURE 23

following the polymer program, the projected economic limit in barrels of oil per day is lower than that projected for conventional flooding operations.

Improvements in oil production rate relative to the projected trend are apparent throughout 1975 and 1976, with the sharpest increase occurring at the beginning of 1977, six months after the start of polymer injection. It is reasonable to assume that the production improvements observed prior to January 1977 were benefits from complementary operations. Based on this assumption and an arbitrary choice of a 14 percent per year decline rate attributable to these increases after January 1, 1977, as also shown on Fig. 23, these complementary operations could have produced as much as one-half of the indicated overall incremental recovery now predicted.

Evalution of the Results of the Polymer Waterflood Project

In general terms, the significance of the results of the polymer waterflood project at North Stanley may be related to Mid-Continent production potential by considering the following features of the North Stanley project as they relate to the larger area:

1. Target oil volume
2. Recovery efficiency
3. Economics.

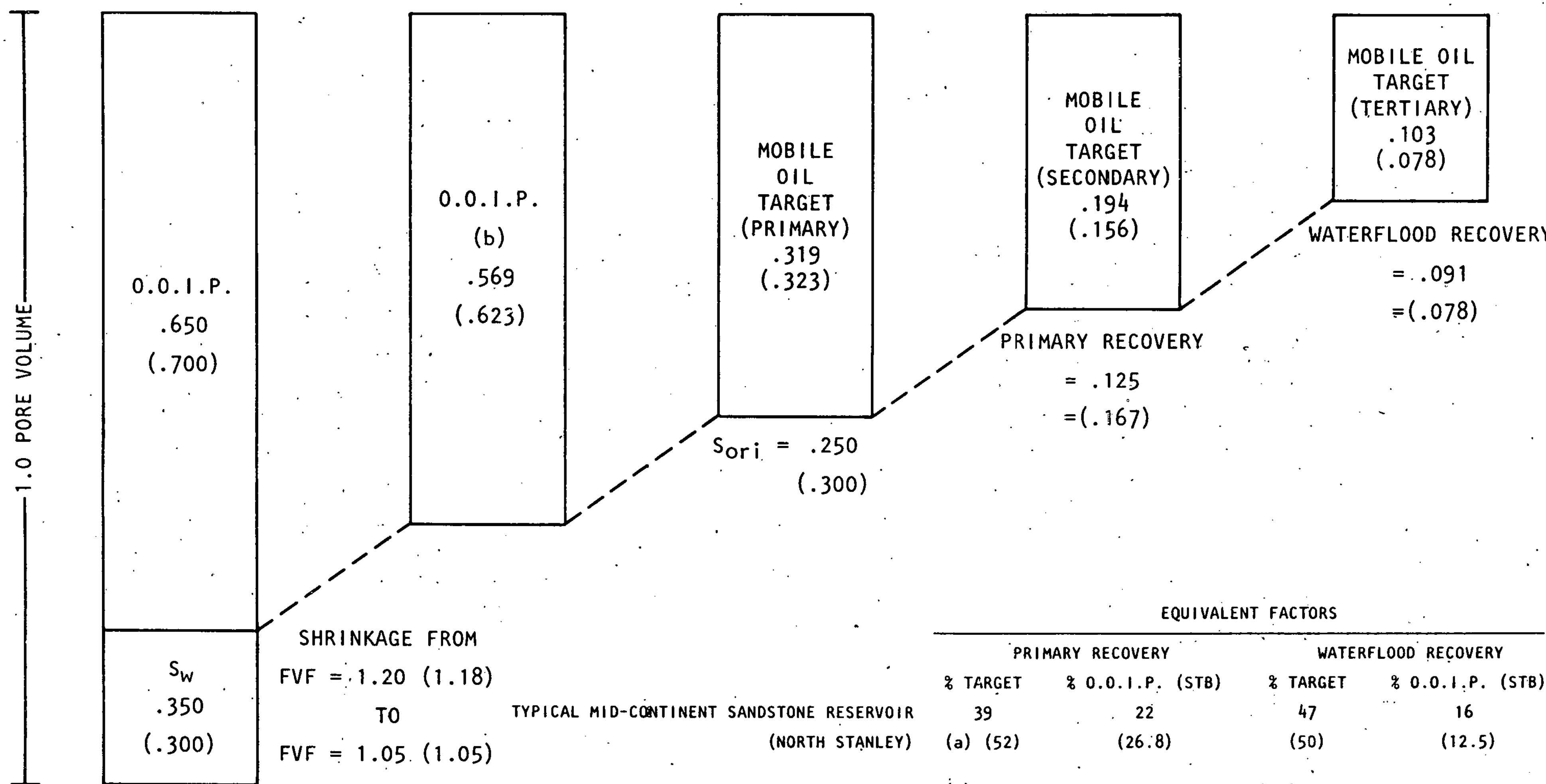
Target Oil Volume

Figure 24 is intended to demonstrate graphically the reduction in volume from original oil in place to that volume of oil which can properly be considered to be the target for mobility control processes. Numbers in parentheses represent North Stanley parameters; the other values represent a typical Mid-Continent sandstone waterflood reservoir. In a typical case the combined effects of shrinkage, irreducible oil saturation (by water or polymer), and primary and secondary recovery reduce the volume of remaining

FIGURE 24

NORTH STANLEY
POLYMER-AUGMENT WATERFLOOD

ESTIMATED MOBILE OIL TARGET FOR MOBILITY CONTROL PROCESSES
AVERAGE MID-CONTINENT SANDSTONE RESERVOIR
DEPLETION FACTORS IN FRACTIONAL PORE VOLUMES
(NORTH STANLEY DATA IN PARENTHESES)



EQUIVALENT FACTORS

	PRIMARY RECOVERY		WATERFLOOD RECOVERY	
	% TARGET	% O.O.I.P. (STB)	% TARGET	% O.O.I.P. (STB)
TYPICAL MID-CONTINENT SANDSTONE RESERVOIR	39	22	47	16
(NORTH STANLEY)	(a) (52)	(26.8)	(50)	(12.5)

(a) INCLUDES VACUUM AND GAS INJECTION

mobile oil to approximately 0.10 reservoir pore volume (PV), or about 18 percent of the original oil in place (OOIP). The equivalent values at North Stanley are 0.08 PV and 13 percent OOIP. These are the projected conditions at depletion by conventional waterflooding.

Estimation of the values that govern the target size as diagrammed on Fig. 24 is somewhat subjective, considering the difficulties in obtaining precise measurements in individual reservoirs and the problem of ensuring uniformity in methods of measurement and interpretation in averaging reported values. It is our opinion that the size of the average polymer target reflected by Fig. 24 represents a liberal estimate. The following are some of the considerations that influence this judgment.

Oil and Water Saturation Values

Although neither the average water saturation nor the average irreducible oil saturation value is subject to precise determination, the combined total of 0.60 PV of "non-target fluids" is a reasonable average expectation.

The estimate of 0.30 for the irreducible oil saturation at North Stanley, based on average core data corrected for shrinkage and expulsion, is 0.03 PV less than measured in the three core-flood tests used in the initial project evaluation (Table 3). The value used for an average Mid-Continent reservoir is consistent with that reported by Koepf (1962) after correction for core handling losses.

Although the residual oil saturation values for this purpose are properly "irreducible" saturation values, the water saturation is not necessarily irreducible. Since the present study attempts to estimate an average value applicable to existent original conditions, the average-case water saturation would be expected to be something greater than the irreducible value. The most extensive set of connate water data available (Koepf, 1962) averages 0.39 for oil zone intervals of Mid-Continent sandstones.

Primary and Waterflood Recovery

Wahl and others (1957) reported correlations useful for estimating primary recovery from solution-gas drive reservoirs. Based on these correlations, the estimated solution-gas drive recovery from a reservoir similar to the average Mid-Continent sandstone waterflood reservoir would be about 20 percent of the original oil in place. This assumes an initial and bubble-point pressure of 2000 psi, solution gas-oil ratio of 400 cubic feet per barrel, and dead oil viscosity of 5 centipoises at reservoir temperature. Because other mechanisms will be effective to some degree in many of the reservoirs, the actual primary recovery could be expected to be somewhat greater than that due solely to solution-gas drive. At North Stanley, for example, the primary recovery of about 27 percent of OOIP indicated by performance is believed to be due, at least in part, to the combined effects of gas injection and gravity drainage in the high-permeability portions of this relatively thick (by Mid-Continent standards) reservoir.

Bush and Helander (1968) reported the results of 86 successful waterfloods in 56 separate fields in 23 Oklahoma counties, finding the average ultimate waterflood recovery to be 2122 stock tank barrels of oil per acre. Assuming an average initial oil saturation of 0.65 and an average formation volume factor of 1.2, the 16 percent recovery of OOIP estimated in Fig. 24 would be equivalent to an average pay thickness of 20 feet in these projects. Averaged oil pay thickness for Oklahoma sandstones from data reported by Koepf (see Table 9) is 11 feet. Assumption of an average pay thickness of less than 20 feet in the floods reported by Bush and Helander would indicate waterflood recovery of greater than 16 percent of OOIP. The relatively low indicated waterflood recovery of 12.5 percent for North Stanley may be attributable to the combined effects of above-average primary recovery and severe anisotopic reservoir conditions.

Biggs and Koch (1974) estimated primary and waterflood recoveries from 63 Colorado waterflood projects. Averaged data from these projects are as follows:

	62 Projects Excluding Rangely	Rangely Field	Total 63 Projects
Average pay thickness, ft.	14	150	16
Average porosity, %	17.8	12.5	17.7
Average permeability, md	158	13	156
Est. primary recovery, % OOIP	25.1	17.5	19.8
Est. waterflood recovery, % OOIP	11.2	21.9	18.6
Total primary and secondary	36.3	39.4	38.4

In applying empirical historical measures of waterflood performance, it is pertinent to note that the limiting WOR achievable under current economic conditions is higher was formerly the case, permitting higher recoveries by conventional flooding.

Theoretical waterflood recovery to a limiting WOR of 100, calculated using a Gruy waterflood performance model for average Mid-Continent conditions as estimated herein, is approximately 70 percent of the total mobile oil target following primary depletion. This calculation assumes linear flow. At high WOR values the areal sweep efficiency would be expected to be high, even for fairly irregular pattern geometry. For example, correlations presented by Caudle and Witte (1959) for the five-spot pattern indicate areal sweep efficiencies of 0.95 or higher for mobility ratios of 10 or less. Assuming an areal efficiency as low as 0.8 yields a calculated waterflood recovery greater than the highest value of shown in Fig. 24.

Finally, it appears that most reservoirs contain some portions which, for practical purposes, can be considered inaccessible to normal displacement processes. These portions, which may range from microscopic to macroscopic in scale, are either totally disconnected from the main reservoir pore network or are so poorly connected as to contribute nothing to the fluid displacement dynamics of the system. To the extent that they exist and are not taken into account in measuring net pay, they reduce the actual mobile oil target compared to that implied by volumetric analysis.

From the above considerations, it is concluded that a combined primary plus secondary recovery of 38 percent of original oil in place is a reasonably conservative estimate for the average Mid-Continent sandstone waterflood. An average remaining mobile oil resource equal to waterflood ultimate is a reasonably liberal statistical measure of the total resource target for mobility control processes.

Polymer Target Recovery Efficiency

The polymer target, as described above, represents the total accessible mobile oil available at 100 percent coverage by polymer flooding. Three major factors restrict the attainable coverage to much less than 100 percent: (1) the economic effects, which necessitate abandonment at a finite water-oil ratio (F-1), (2) the effects of adverse distribution of target oil caused by flooding prior to polymer injection (F-2), and (3) the presence of severe anisotropies in the physical system or in the distribution of injected fluid volumes and pressures, which prevent achieving maximum efficiency (F-3).

Figure 25 is a diagrammatic representation of the approximate effects attributed to these factors at North Stanley and the typical Mid-Continent waterflood reservoir in this study. These will be discussed in order below.

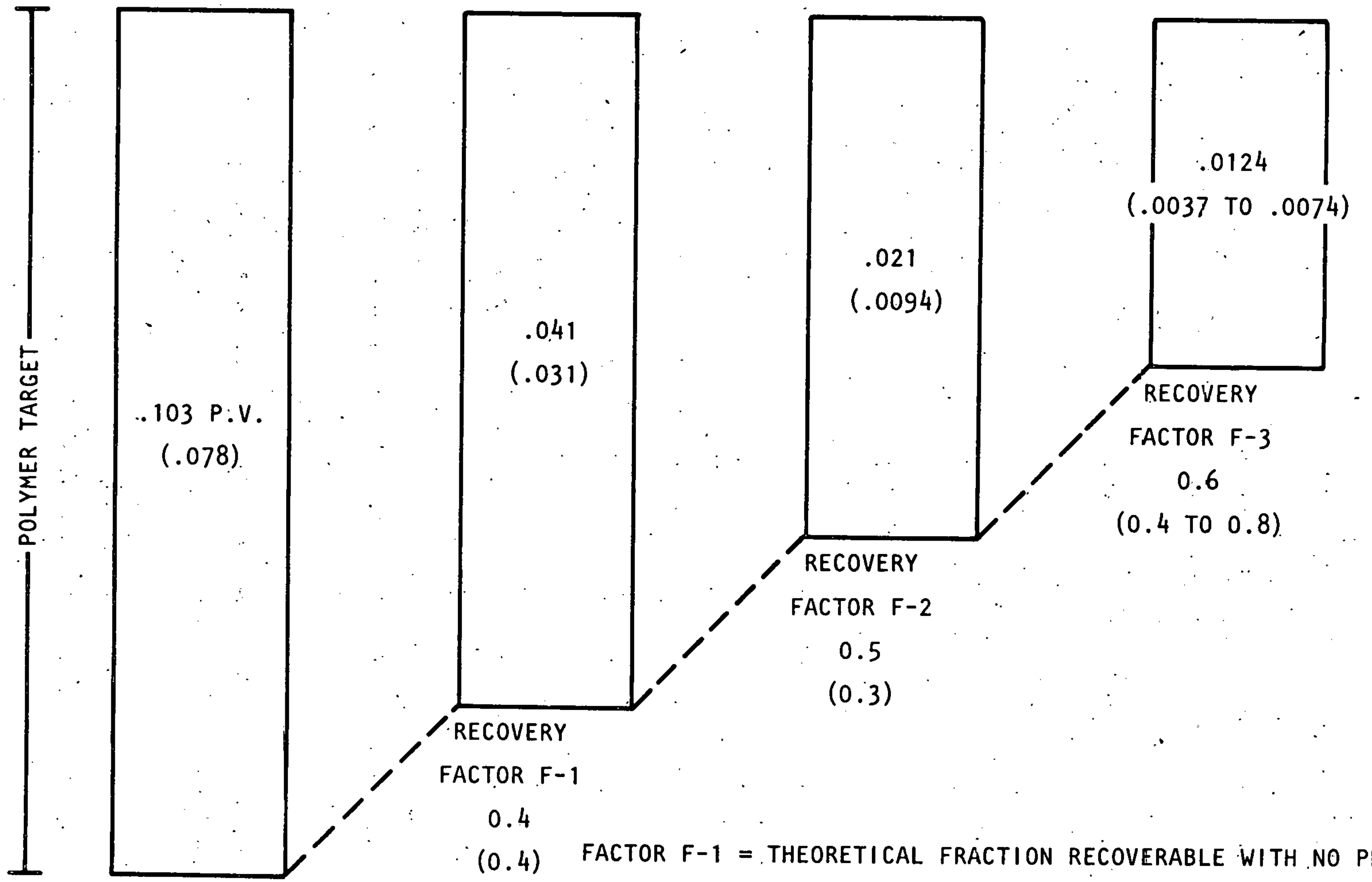
Factor F-1, Effect of Limiting Water-Oil Ratio (WOR)

Factor F-1 can be considered a polymer target "coverage" factor for a particular abandonment water-oil ratio. It assumes the augmented waterflood process is initiated immediately following primary depletion. In the absence of major anisotropies, it is determined by permeability variation, mobility ratio, and unit costs of producing and injecting water (reflected in limiting WOR). For specific cases, this factor could vary widely. Since, there have been few published results of investigations of this factor for various pertinent combinations of the controlling parameters,

FIGURE 25

NORTH STANLEY
POLYMER-AUGMENT WATERFLOOD

POLYMER TARGET RECOVERY EFFICIENCY FACTORS
AVERAGE MID-CONTINENT SANDSTONE RESERVOIR
(NORTH STANLEY DATA IN PARENTHESES)



FACTOR F-1 = THEORETICAL FRACTION RECOVERABLE WITH NO PRIOR WATERFLOODING

FACTOR F-2 = CORRECTION FOR STAGE OF WATERFLOOD DEPLETION

FACTOR F-3 = CORRECTION FOR INEFFICIENCIES DUE TO SEVERE ANISOTROPIES AND PRACTICAL OPERATIONAL LIMITATIONS particularly at high water-oil ratios, further investigation is needed to better define this factor. For the purposes of this study a value of 0.40 has been estimated as applicable both to North Stanley and to the average Mid-Continent case.

Factor F-2, Effect of Prior Flooding

Factor F-2 accounts for the further reduction in target recovery efficiency as a result of prior conventional waterflooding. This effect derives from the increasingly skewed distribution of target oil in favor of those portions of the reservoir with the lowest flow capacities as flooding progresses.

Although the significance of this factor has been generally recognized, little analytical work has been reported regarding its quantitative effect. Jewett and Schurz (1970) calculated the effects of three different amounts of brine pre-flush, up to 0.5 pore volume, for a hypothetical base case of reservoir and economic conditions. The three cases represented water-oil ratios at the beginning of polymer injection of approximately 1.1, 7.0, and 12.0. Assumed WOR at the economic limit was 24. For the particular base case assumed, the computed recoveries by polymer were 88 percent, 79 percent, and 67 percent of the computed recovery with no brine pre-flush. In Fig. 26 the general shape of the relationship between factor F-2 and beginning WOR is postulated, based on the three points computed for the case reported. This relation will vary for different reservoir and economic conditions. In the absence of a general solution, an average relation of the same general form, adjusted to an abandonment WOR of 100, was assumed for the purposes of this analysis. This correlation is also shown in Fig. 26.

Factor F-3, Severe Anisotropic Conditions and Practical Operational Limitations

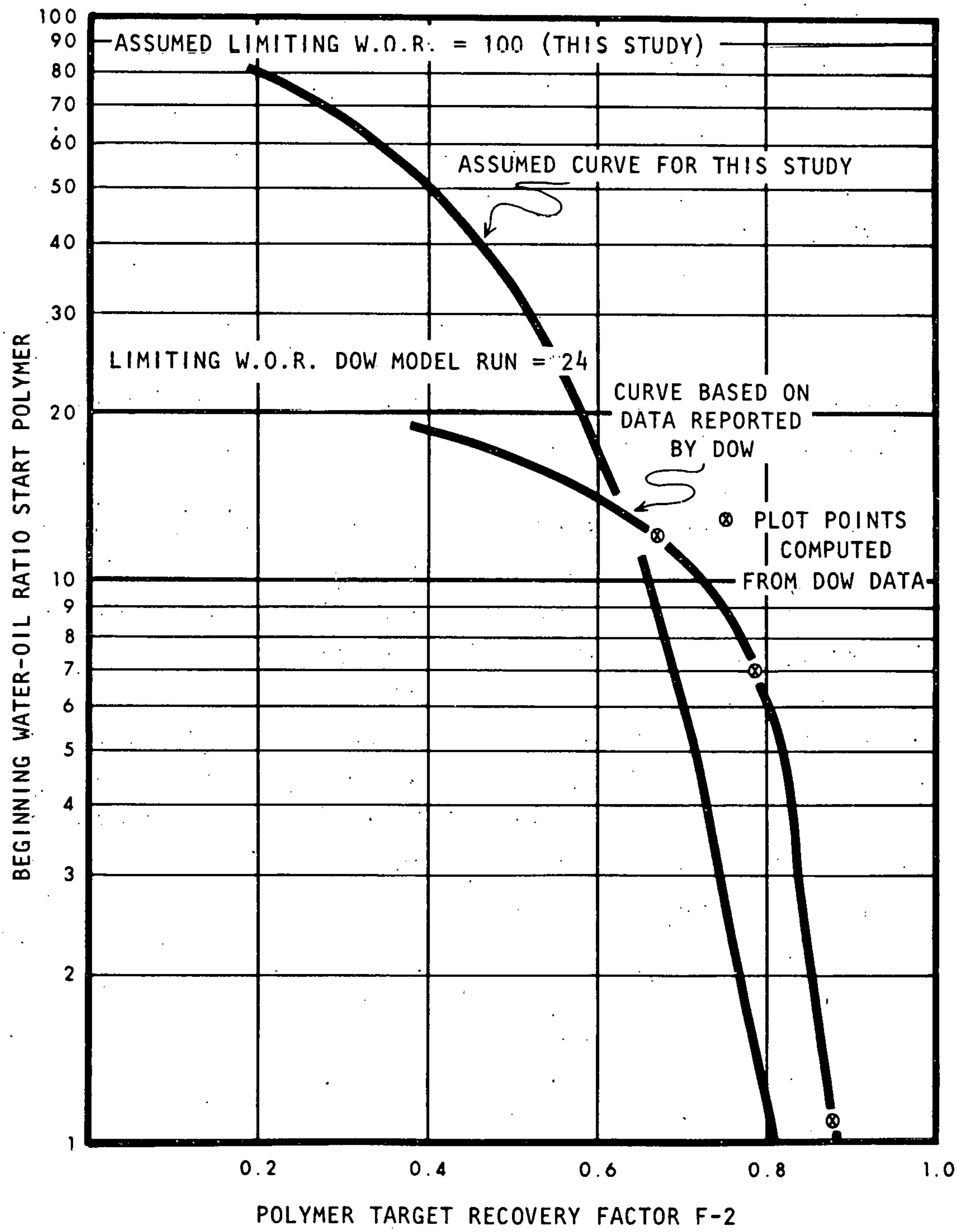
These conditions are intimately associated because of the restraints imposed by operational limitations on (1) achieving a perfect custom-designed

FIGURE 26

NORTH STANLEY
POLYMER-AUGMENT WATERFLOOD

POLYMER TARGET RECOVERY FACTOR F-2
VS
WATER-OIL RATIO AT START OF POLYMER

$$\text{FACTOR } F_2 = \frac{\text{RECOVERY WITH BEGINNING W.O.R. INDICATED}}{\text{THEORETICAL RECOVERY WITH NO PRIOR WATERFLOODING}}$$



pattern of injection and production relative to the specific geometry of the reservoir, particularly where severe anisotropies exist in reservoir geometry, and (2) achieving and maintaining ideal levels and balance of pressure and volumes for any given pattern.

Probably the most important problems or sources of problems in this category are:

1. Fixed starting conditions of physical facilities (well pattern, subsurface equipment, and surface facilities). Given a total system of fixed facilities, most of which have some utility in a contemplated project, the optimum design for maximizing economic return will always represent some compromise in recovery efficiency below that associated with designs not burdened by existing lower-cost alternatives to "ideal" design.

2. Hazards produced by previous history. The presence of old abandoned wells, casing leaks, and other mechanical conditions contributing to loss of injected fluids from the reservoir system can directly affect the efficiency.

3. Extensive fracturing. Fractures or incipient fractures may be fairly common in Mid-Continent reservoirs; they can impose anisotropic pressure and flow patterns, reduce flow through reservoir the matrix, and limit operating flexibility.

4. Restraints on injection pressure which limit attainable production rates. An essential feature of a mobility-control process is reduced mobility of the displacing fluid in the reservoir environment. This reduces the fraction of the displacing fluid entering the more highly swept portions and concomitantly reduces the produced water-oil ratio. It does not, however, necessarily result in an increase in oil production rate, since this can result only from an increase in the actual rate of entry of displacing fluid.

fluids in the system, which can be accomplished only by increasing sand-face pressure in the injection wells or decreasing the bottomhole pressure in the producers. Freedom to increase sand-face injection pressure is limited, at least by breakdown pressure and in some cases by mechanical facilities limitations. Decreasing the producer bottomhole pressure entails higher lifting costs and also imposes certain practical mechanical limitations on flexibility.

Based on the analysis represented by Figs. 24 and 25, we would consider a liberal estimate of the polymer recovery potential from an average Mid-Continent sandstone reservoir to be 0.012 pore volumes, or 12 percent efficiency of recovery of the existing target. The indicated North Stanley recovery efficiency is 4.8 percent attributable exclusively to the polymer slug, or 9.6 percent for the total project.

In summary, consideration of the polymer target oil volume and factors affecting recovery have led to the following conclusions.

1. A liberal measure of the total mobile oil resource (not economically recoverable by conventional flooding) in an average Mid-Continent sandstone waterfloodable reservoir has been developed. It is approximately equal to the anticipated ultimate recovery attributable to conventional waterflooding.

2. The North Stanley Burbank reservoir differs from the average Mid-Continent sandstone waterflood principally in the degree of anisotropic conditions and the state of prior depletion by waterflooding.

3. Only a small fraction of the resource target would be considered recoverable from the average reservoir.

Economic Considerations

For the purposes of this review a simple measure of economic success has been adopted, which will be referred to as the economic success ratio (ESR). It is defined as the ratio of the present value of the incremental net ongoing income to the present value of the "up-front" costs. Up-front costs include all expenditures involved in evaluation, design, system modifications, new installations, and purchase of the required chemicals. Incremental net ongoing income is the market value of the incremental oil produced, less the incremental ongoing costs attributable to the polymer project.

In examining the effect of crude oil price, we have used the term "Net Revenue per Barrel" for comparison between cases, in order to eliminate the need to account for variations in working interest fractions. The equivalent gross crude oil market price for North Stanley is about 1.2 times the net revenue per barrel; for the average Mid-Continent reservoir it is probably in the range of 1.15 to 1.25.

The specific economic outcome of the North Stanley project was reported in Kewanee's final report, which anticipated an incremental oil recovery of 900,000 barrels from the project. Even at this recovery and allowing for partial reimbursement of costs by DOE, the estimated specific economic outcome would be marginal, insufficient to attract investment capital in similar ventures. At a current estimated incremental recovery for the total project of about one-half of the above, and ignoring DOE's participation, it is obvious that the project can only be classed as an economic failure at the current price of oil.

There are at least two highly site-specific features of the economic environment effective at North Stanley, other than the participation by DOE, which need to be recognized in relating the economic outcome of this project to other candidates:

1. The effect of the two-tier oil pricing structure. Under the conditions specific to North Stanley during the project and projected through 1984, all of the recovery attributable to conventional waterflooding and about 60 percent of the incremental recovery anticipated by Kewanee would be subject to the lower-tier price limit (averaging about $6 per barrel over the predicted life). Only 40 percent of the projected incremental recovery by polymer would qualify for upper-tier price (averaging about $13 per barrel over the predicted life). None of the production qualified for stripper well price.

2. A predicted extended producing life, under polymer flooding, of five years beyond the four-year remaining life of conventional waterflood operations. The incremental cash flow is burdened, therefore, with five years of full operating costs out of the total nine-year life. It is notable that this cost feature, all of which is chargeable against the project, is equivalent to $4.8 million -- more than twice the cost of chemicals employed.

In order to represent North Stanley economics in terms useful for relating to other candidates, DOE participation is ignored and the economic outcome expressed as the ESR that would be indicated for an assumed range of crude oil price conditions. The value of all of the estimated project incremental recovery is included in this analysis. No inflation or escalation effects have been introduced.

Figure 27 is an extended projection of North Stanley production performance, with and without polymer flooding. To simplify economic comparisons, the average Mid-Continent waterflood reservoir case is represented on the oil production graph by assuming that the additional incremental production attributable to an average case of the same size (acre feet) as North Stanley over that expected at North Stanley would be obtained over a 3-year period represented by the 3 years preceding the start of polymer injection at North Stanley (extension A on Fig. 27 oil production curve). Following that 3 years, performance history is assumed to be the same as North Stanley. A similar technique has been employed for representing a

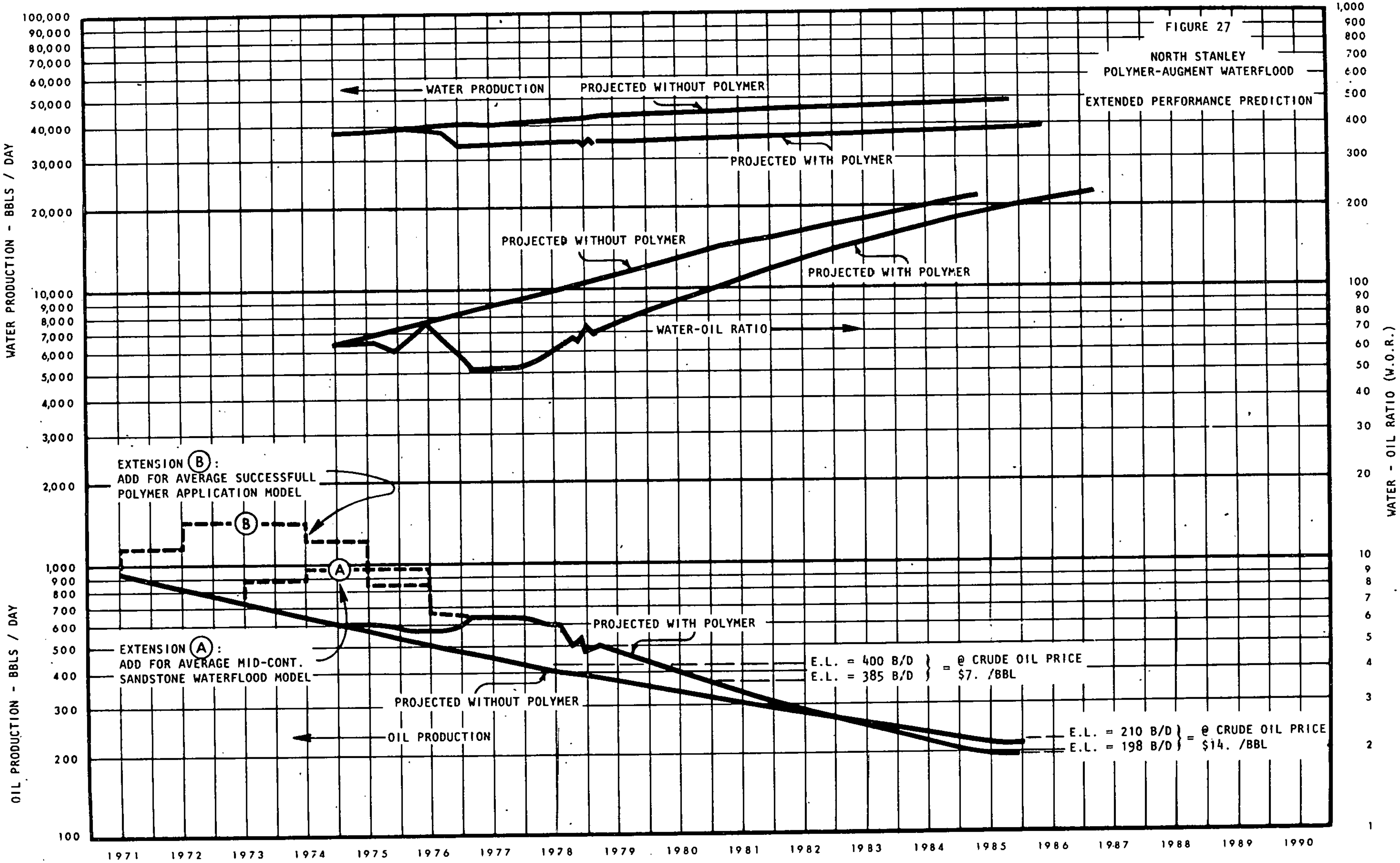


FIGURE 27
NORTH STANLEY
POLYMER-AUGMENT WATERFLOOD
EXTENDED PERFORMANCE PREDICTION
WATER PRODUCTION
PROJECTED WITHOUT POLYMER
PROJECTED WITH POLYMER
PROJECTED WITHOUT POLYMER
PROJECTED WITH POLYMER
WATER-OIL RATIO
EXTENSION (B):
ADD FOR AVERAGE SUCCESSFULL
POLYMER APPLICATION MODEL
EXTENSION (A):
ADD FOR AVERAGE MID-CONT.
SANDSTONE WATERFLOOD MODEL
PROJECTED WITH POLYMER
E.L. = 400 B/D
E.L. = 385 B/D
= @ CRUDE OIL PRICE
$7. /BBL
PROJECTED WITHOUT POLYMER
OIL PRODUCTION
E.L. = 210 B/D
E.L. = 198 B/D
= @ CRUDE OIL PRICE
$14. /BBL
WATER PRODUCTION - BBLS / DAY
OIL PRODUCTION - BBLS / DAY
WATER - OIL RATIO (W.O.R.)
1971 1972 1973 1974 1975 1976 1977 1978 1979 1980 1981 1982 1983 1984 1985 1986 1987 1988 1989 1990

performance model for an average successful polymer project (extension B on Fig. 27). The latter will be reviewed further under Section IV.

Cost factors used in the economic analysis are based on information reported by Kewanee for North Stanley after adjustments for escalation before and after January 1979. The following summarizes these factors and an assumed "standardized" time distribution which we have employed for each case.

Year or Period of Project Life	Chemical and Related Costs (Thousands of Dollars)	Other Up-Front Costs (Thousands of Dollars)	Incremental On-Going Costs (Thousands of Dollars/Yr)
1		140	
2		350	
3	2400	210	
Yr. 3 through project remaining life of conventional waterflood			33.6
Extended life-polymer flood over conventional waterflood			739.2
Shortened life-polymer flood less than conventional waterflood			(705.6)

These costs factors are believed to be reasonably representative of what might be expected (as of January 1, 1979) for an average project similar in size to North Stanley.

Three conditions of crude oil pricing have been analyzed:

1. An assumed net revenue of $5.88 per barrel (equivalent to about $7 gross market price). This is the approximate average value effective at North Stanley as of January 1979, and is assumed applicable to all barrels regardless of rate or whether attributable to conventional or augmented flooding.

2. An assumed crude price twice the above ($14 per barrel gross = $11.76/WI net) applied uniformly to all oil production. This is slightly higher than the average upper-tier crude oil price ($12.75) applicable as of January 1979.

3. A differential pricing condition wherein all conventional waterflooding oil is priced at $5.88 per barrel (WI Net), and all incremental oil is priced at $11.76 per barrel.

Table 5 and Fig. 28 reflect the results of this analysis for North Stanley and for the average Mid-Continent waterflood cases. These results show that for the levels of performance estimated for North Stanley, doubling the crude price in effect as of January 1979 would not significantly improve the economic position of the project. In fact, all of the improvement reflected is the result of the polymer project receiving a small net credit to incremental ongoing costs under the longer-life condition, as contrasted to charges totaling about $1,300,000 under the lower crude price conditions where the economic life of the polymer flood exceeds the conventional waterflood life.

Of particular significance is the economic paradox demonstrated by this analysis relating incremental oil recovery to increased crude prices. It will be noted that under each case the incremental recovery attributable to polymer is substantially reduced (57 percent at North Stanley and 36 percent for the average Mid-Continent case) by doubling crude oil price. This basically arises from the fact that increasing the crude oil price permits a greater recovery of the finite mobile oil target by conventional flooding, leaving a smaller target for other processes. This effect is not significant in EOR processes where the total residual oil is the potential target, or for polymer-augmented waterfloods operating with low WOR ranges. However, as operations extend into the higher WOR ranges and the total size of the target becomes small, it probably becomes a significant effect.

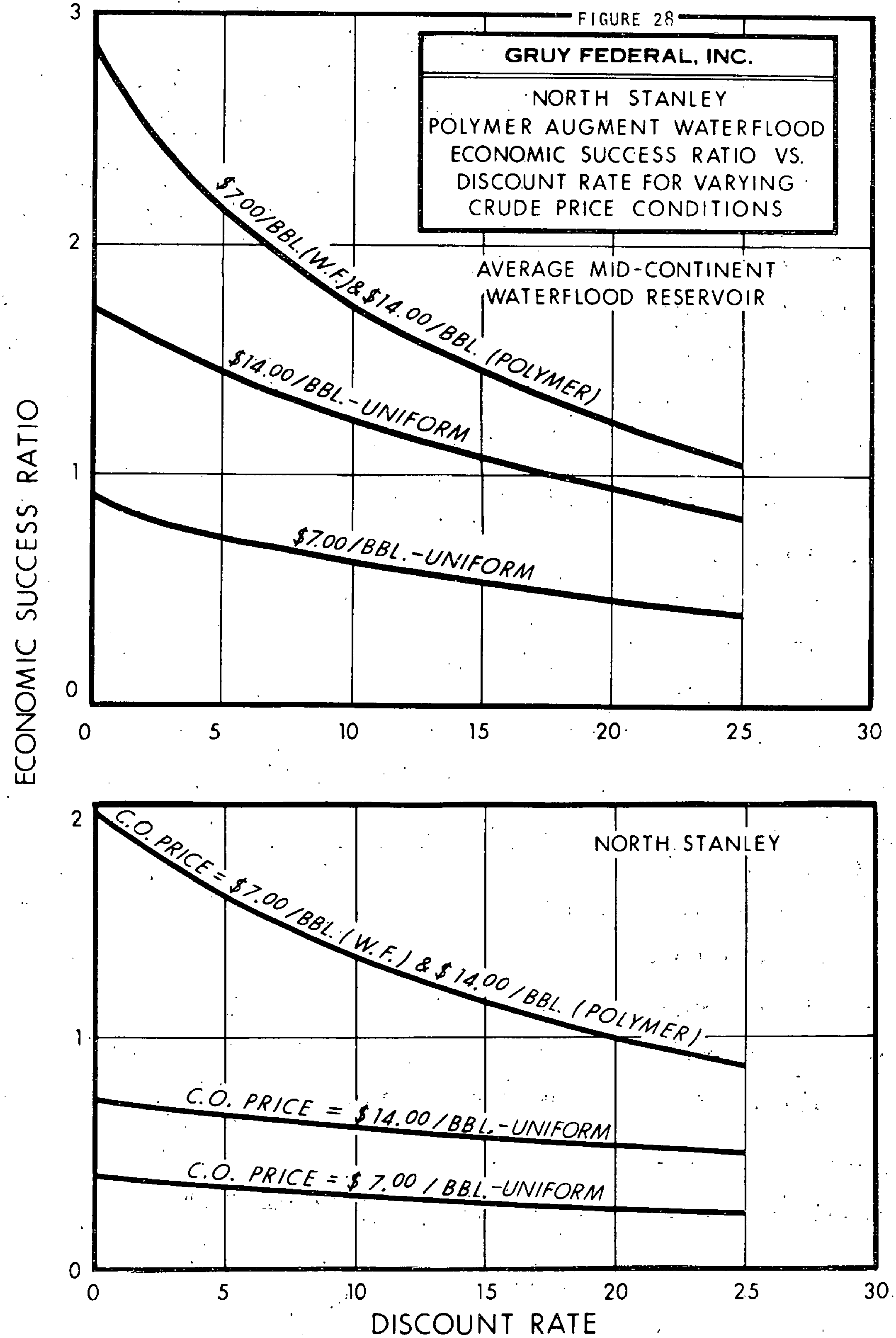
TABLE 5

SUMMARY OF COMPARATIVE PERFORMANCE AND ECONOMIC OUTCOMES
NORTH STANLEY AND AVERAGE MID-CONTINENT WATERFLOODS

	North Stanley			Avg. Mid-Continent		
	Undis-counted	Disc. @ 15%	Disc. @ 25%	Undis-counted	Disc. @ 15%	Disc. @ 25%
Crude oil price $7/bbl applied uniformly						
Recovery in thousands of barrels						
Est. ult. w/ polymer	5440			5700		
Est. ult. w/o polymer	5000			5000		
Polymer increment	440			700		
Econ. success ratio*	0.40	0.30	0.25	0.90	0.57	0.44
Crude oil price $14/bbl applied uniformly						
Recovery in thousands of barrels						
Est. ult. w/ polymer	5940			6200		
Est. ult. w/o polymer	5750			5750		
Polymer increment	190			450		
Econ. success ratio	0.72	0.57	0.49	1.71	1.11	0.87
Crude oil price $14/bbl for incremental oil, $7/bbl for conventional waterflood oil						
Recovery in thousands of barrels						
Est. ult. w/ polymer	5940			6200		
Est. ult. w/o polymer	5000			5000		
Polymer increment	940			1200		
Econ. success ratio	1.95	1.15	0.88	2.93	1.50	1.07

$$\text{*Economic success ratio} = \frac{\text{P.V. incremental net ongoing revenue}}{\text{P.V. up-front costs}}$$

FIGURE 28


GRUY FEDERAL, INC.
NORTH STANLEY
POLYMER AUGMENT WATERFLOOD
ECONOMIC SUCCESS RATIO VS.
DISCOUNT RATE FOR VARYING
CRUDE PRICE CONDITIONS
AVERAGE MID-CONTINENT
WATERFLOOD RESERVOIR
$7.00/BBL.(W.F.)& $14.00/BBL. (POLYMER)
$14.00/BBL.-UNIFORM
$7.00/BBL.-UNIFORM
NORTH STANLEY
C.O. PRICE = $7.00/BBL.(W.F.) & $14.00/BBL. (POLYMER)
C.O. PRICE = $14.00/BBL.-UNIFORM
C.O. PRICE = $ 7.00 / BBL.-UNIFORM
ECONOMIC SUCCESS RATIO
DISCOUNT RATE
0
1
2
3
5
10
15
20
25
30

This effect is also reflected in Fig. 22, where the inevitable convergence of the WOR vs. cumulative recovery curves at high WOR values is apparent. The extent to which this may be a factor in any particular prospect is highly site-specific, and no attempt has been made to generalize it quantitatively.

As for the average Mid-Continent case, the results of the above analysis suggest that a uniformly applied crude oil price higher than $14 per barrel would be required to justify investment in moderate- to high-risk projects.

The third crude price condition examined assumes a gross market price of $7 per barrel applicable to all projected recovery from conventional flooding and $14 per barrel applicable to all incremental oil. This condition would not raise North Stanley economics to an acceptable level, and the apparent benefits in the average Mid-Continent case would probably represent no more than a marginal incentive for projects bearing substantial risk. Although conceptually this condition provides increased incentive for investment in polymer processes because of the apparent incremental increase in production and income due to polymer injection, three features seem to be pertinent in such considerations.

1. The controlling elements of the price structure with regard to incremental oil credited to polymer are those that exist at predicted abandonment. This may be several years in the future and -- especially in the case of controlled prices--subject to considerable uncertainty for any particular project analysis.

2. For any project initiated, the differential pricing structure does not contribute to any increase in total oil recovered compared to application of a uniform price.

3. Two-level pricing would not encourage the application of large-scale remedial work in existing waterfloods to achieve a higher efficiency. About half of the recovery achieved at North Stanley is believed to have come from such efforts (see p. 51).

II. REVIEW OF SCREENING CRITERIA IN LIGHT OF STANLEY STRINGER PROJECT RESULTS

One objective of this study was to define screening criteria for mobility control processes in light of the North Stanley project results.

It is important to recognize initially that, as applied to polymer-augmented waterflooding studies, general screening criteria are useful primarily as cutoff values for eliminating reservoirs with insufficient potential for consideration in broad-based studies such as the one covered by this report. It should be emphasized that the data used in the screening criteria are not sufficient either for priority ranking of candidates or for evaluating a particular prospect. As a minimum, more information than is generally available is necessary for the former, and the latter requires intensive technical measurement and analysis on each prospect.

The following discussion reviews the latest published criteria and their relation to North Stanley parameter values and performance. Included also are observations concerning the utility of each with particular reference to Mid-Continent conditions, and suggested modifications for improved utility.

While conditions at North Stanley were known to be decidedly less than ideal for polymer flooding, a powerful incentive existed to test the feasibility of a relatively inexpensive, commercially available enhanced recovery process in a reservoir that typifies much of the Mid-Continent oil reserves.

Table 6 compares the reservoir conditions in North Stanley at the time the project was started with the most recently published screening criteria. It is seen that North Stanley was outside the recommended range for three parameters (mobile oil saturation, producing water-oil ratio, and channeling/fractures) and that the mobility ratio and oil viscosity were borderline. Yet incremental oil recovery to date indicates that the project was

TABLE 6

COMPARISON OF NORTH STANLEY RESERVOIR PARAMETERS
WITH CURRENT SCREENING CRITERIA

Parameter	Latest Published Screening Criteria	North Stanley
Oil viscosity, cp	preferred range 2-200	2.4
Mobility ratio, water/oil	greater than 1	1.1
Mobile oil saturation	greater than 0.10 PV	0.09-0.06 PV
Current water-oil ratio	less than 15	67
Permeability, md	greater than 20	average 300, range 10 to 1500
Temperature, °F	less than 200	105
Lithology	sandstone	sandstone
Channeling-fractures	"no gross channeling or major natural fractures"	high permeability zones and natural fracture system within project area

*Based on irreducible oil saturation estimates ranging from 0.30 to 0.33.

technically, if not economically, successful. Further, analysis of the North Stanley test results points up the fact that several of the parameters listed in the screening table are too closely interrelated to be used individually as reliable rejection criteria.

Oil Viscosity. As a generalization, very low oil viscosities lead to higher waterflood recovery efficiencies and low polymer targets, and high oil viscosities tend to limit the potential efficiency of either conventional or polymer-augmented waterflooding. Viscosity data are not readily available for the majority of reservoirs in the Mid-Continent; however, viscosity can be estimated from correlations based on the API oil gravity, which is commonly available. It is simpler, therefore, to use oil gravity directly as the screening criterion. The acceptable range is 16-42°API for the oil viscosity range (2 to 200 cp) commonly considered appropriate for screening. The oil viscosity at North Stanley is 2.4 cp (39°API), close to the lower limit.

Mobility Ratio. Mobility ratio has very limited utility as a general screening criterion because data are sparce. Knowledge of the mobility ratio in a specific project requires, first, a knowledge of oil viscosity, which is not usually available, and second, relative permeability data, which are even less frequently available. Screening on the basis of oil gravity alone accomplishes virtually the same purpose. The North Stanley mobility ratio value of 1.1 largely reflects the effect of the low oil viscosity.

Permeability. Early screening criteria included a minimum permeability of 20 md. This was slanted toward screening candidate reservoirs, most of which at that time were still undergoing primary depletion, to exclude those where injectivity would be inadequate for a water injection project. At present, however, the bulk of the Mid-Continent polymer target oil is in reservoirs that are being waterflooded. Field operations have shown that the polymer solution, when selected to suit the reservoir conditions, has nearly the same total injectivity as water. Therefore it would appear that any Mid-Continent reservoir not already suffering from poor injectivity could be included for consideration without concern for permeability.

Mobile Oil Saturation. Previous screening lists specify a minimum value of 0.10 pore volume (PV) for this parameter. At North Stanley, the mobile oil saturation was indicated to be 0.16 PV at the time waterflooding was started in 1959, and it had been further reduced to 0.09 PV by the time the polymer test was started. As Table 7 shows, the available polymer target under these saturation conditions is minimal. Actual performance at North Stanley does not dictate downward revision of the 0.10 value as a general screening criterion. However, for specific prospect evaluation where all other conditions are highly favorable, this parameter alone should not be used to reject a prospect.

Beginning Water-Oil Ratio (WOR). The current WOR is a rough measure of the extent to which the distribution (and potential recovery efficiency) of the remaining mobile oil has been adversely affected by prior flooding. It is also an indicator of the proximity of the economic limit by conventional flooding which can, independently of process performance, adversely affect project economics. The latter effect is the result of extended-life operating costs for projects commenced near the end of normal flood life. Both effects are discussed in Section III.

The beginning WOR at North Stanley was 67, whereas the screening criterion is 15 or less. North Stanley performance suggests that 67 is too high, but provides no clue as to what the limit should be. A value of 15 may be too conservative, particularly when higher crude oil prices permit economical operations to high WOR values. In the absence of a better general definition of the above effect, a more liberal cutoff value of 25 for general screening purposes seems appropriate.

In specific project evaluation, a critical study of WOR and WOR history, in connection with injected-produced fluid balance and other waterfood performance data, can give valuable clues to the existence of injection fluid

TABLE 7

MOBILE OIL SATURATIONS AT NORTH STANLEY

Time	SOI	SOM(1)	Mobil oil, Stock tank barrels per acre-foot (2)
Discovery	0.700	0.400	473
Start of waterflood	0.456	0.156	207
Start of polymer test	0.387	0.087	116
Remaining reserves for the basic waterflood		0.009	12
Available as net polymer target		0.078	104

(1) Based on irreducible SOR = 0.300.

(2) Based on FVF = 1.18 at discovery and 1.05 at start of waterflood.

losses via casing leaks, thief zones, large gas caps, etc., or of severe channeling conditions. For example, in the North Stanley waterflood, the initial oil response to injection was at a WOR greater than 10 (see Fig. 22), which may be attributable to early channeling in the project area.

Channeling and Fractures. Previous screening lists definitely prohibit these conditions, and it is clear they should be considered as negative factors which will statistically reduce the probability of success in those reservoirs where they occur.

The presence of fracturing and channeling at North Stanley is well established. Nevertheless, the effect on conventional waterflooding efficiency appears to have been less severe than might have been expected. This may be due to the fact that the pattern was designed in recognition of the fracture system, and possibly even to some compensating benefits of the fractures, which permitted higher injection into less permeable portions of the reservoir. Further, although these conditions definitely appear to have hampered performance of the polymer project, it was possible to mitigate the problem to some degree by the use of selective plugging treatments. These techniques may become even more effective with more field experience and technological development.

For any specific prospect, therefore, the implication of the presence of fractures and/or high-conductivity flow channels requires careful analysis with regard to the possibilities for improving recovery either with or without polymer flooding.

Lithology. The lithology at North Stanley is sandstone, as is specified in previous screening lists. The reason for this specification was not the petrophysical fabric of carbonates nor any chemical incompatibility between the matrix and the polymer; it was the frequent association of carbonate reservoirs in the Mid-Continent area with grossly anomalous conditions, such as large-scale fracturing and faulting, complete underlayment by water zones, etc. It would be clearer if these conditions were more specifically denoted in the screening lists.

Temperature. Previous criteria state a maximum of 200°F. This would correspond to a depth on the order of 10,000 feet in the Mid-Continent region. Thus it would appear that, in general, reservoir temperature is not enough of a limiting factor in the Mid-Continent polymer target to justify including it in a list of screening criteria for this region.

Selection of Fields for Review. Based on the information derived from the North Stanley demonstration project, it is proposed that the screening criteria for the Mid-Continent area be revised as shown in Table 8. With this set of criteria in mind, Gruy Federal undertook a review of Mid-Continent oil fields.

TABLE 8

SCREENING CRITERIA FOR POLYMER APPLICATIONS
MID-CONTINENT REGION

Parameter	Range of Feasibility
Oil gravity	Between 16 and 42°API
Injectivity	Sufficient to support waterflood economics; usually 0.10 bbl/day per acre-foot minimum
Mobile oil saturation	0.10 PV minimum
Current water-oil ratio	Less than 25:1
Channeling/fractures and Gross reservoir anomalies	Reject candidates if conditions are known to be too severe to permit conventional waterflooding

III. REVIEW OF GEOLOGICAL AND ENGINEERING CHARACTERISTICS OF MID-CONTINENT OIL FIELDS AS CANDIDATES FOR THE POLYMER PROCESS

Because there are 17,000 oil reservoirs in the project area, the present review was limited to those fields that would logically merit further consideration as polymer process candidates.

To facilitate the study and increase its utility, three primary assumptions were made, based on minimum size and practical considerations:

1. For an oil field to be considered as a candidate for polymer-augmented waterflooding, it should be large enough to support the expenditures for necessary geological and engineering studies.

2. The gravity of the crude oil should be in the range of 16-42° API.

3. Fields that have had uncontrolled waterflood projects should not be considered because costs of remedial work are generally prohibitive.

The primary screening in the study region was performed using the following criteria:

1. Sandstone reservoir lithology

2. Cumulative production greater than 1,000,000 barrels of oil

3. Five or more producing wells

4. Pay interval at least five feet thick

5. Oil gravity between 16° and 42° API

6. No evidence of uncontrolled waterflooding.

Items 2, 3, and 6 are field-level information and any field containing a sandstone reservoir that also met the additional criteria 4 and 5 was retained.

The Petroleum Data System (PDS) at the University of Oklahoma was the primary source for Items 1-4. Access was gained through the General Electric Mark III Computer Network, an interactive time-sharing system. The PDS relies heavily on the International Oil Scouts Association's annual reviews.

Other source documents and the open literature were used in augmenting Items 1 and 6 (see bibliography). This preliminary screening procedure was designed to locate reservoirs that warranted further examination.

The Petroleum Data System carries information at the field level, i.e., cumulative production, number of producing wells, etc., and also at the pool level, i.e., producing formation, depth, thickness of producing interval, etc. The completeness of information for a specific area depends mainly upon legislated reporting requirements for the area. Field-level information, except for combined fields, was found to be complete in the project area. Unfortunately, pool or reservoir information is scanty. Compounding this basic problem is the fact that the field information is attached to one of the pool records within a field, but there is no provision for direct access to either the pool data or field data exclusively on that record. This introduced considerable difficulty into the screening process.

In Oklahoma, a significant number of fields have been combined for reporting and proration purposes. PDS does not carry the number of producing wells or annual production for combined fields. This lack of field-level information has precluded further review of some fields, and they are included in the fields with which they have been combined.

The first step in screening was to limit consideration to fields with a cumulative production of at least one million barrels of oil and at least five active wells. Cumulative production and active well counts were the most complete entries in PDS. In certain cases, lithologies of the producing horizons were readily available and fields containing only carbonate reservoirs could be eliminated.

Since information at the pool level is so variable, the PDS screening process was not as definitive as initially envisioned, and lack of data made it impossible to eliminate many fields or pools.

This necessitated intensive review of additional data sources. State geological surveys and geological societies in the Mid-Continent area were contacted for information. In some cases, the geological societies have published reports containing relatively complete data on selected fields (see bibliography). Waterflood projects were identified through Interstate Oil Compact Commission reports and commercial service documents.

Using the data sources described, the number of fields in the Mid-Continent area meeting these preliminary screening criteria was reduced to 730. At this point a subset of 88 fields, consisting of those fields with production greater than 200,000 barrels of oil per year, was selected for detailed review.

The open literature on these 88 fields was then reviewed for information. A computerized data search was conducted, using the Regional Information and Communication Exchange (RICE) system, which incorporates Petroleum Abstracts and the data base Georef.

An exhaustive search of the technical literature showed that the 88 fields contain a total of 618 reservoirs, 332 of which can be identified as sandstone reservoirs. Of these, detailed reservoir information (such as permeability, porosity, oil gravity, viscosity, and waterflood acreage) can be assembled on 53 reservoirs. It should be kept in mind, however, that the screening criteria discussed here do not include all information required for evaluation purposes, and data on other essential criteria is limited. The open literature contains almost no information on reservoir characteristics, such as degree of heterogeneity, mobility ratio, relative permeability, and residual saturation, for the Mid-Continent area.

The following is a summary of the pertinent reservoir information collected.

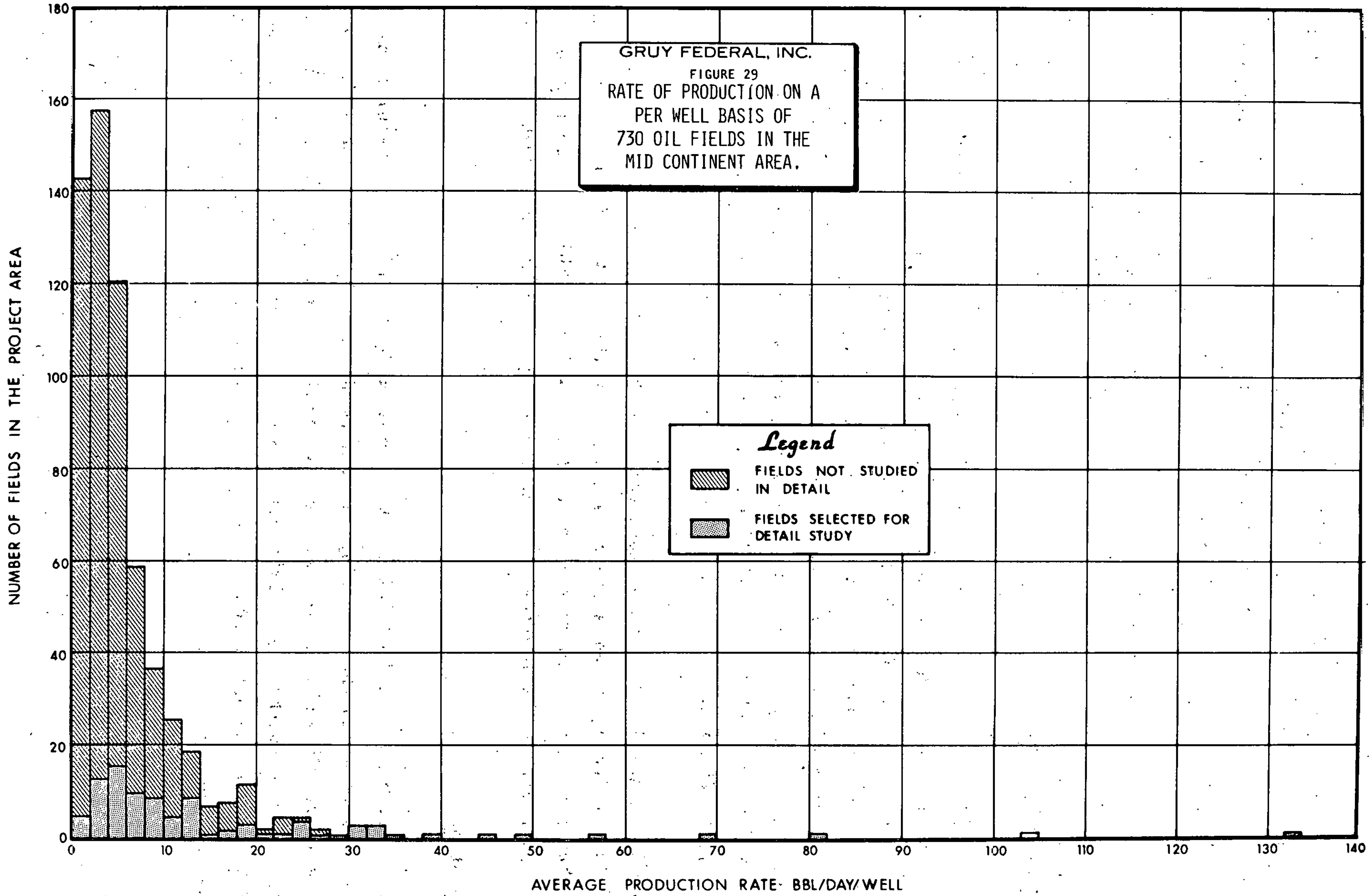
Production Rate

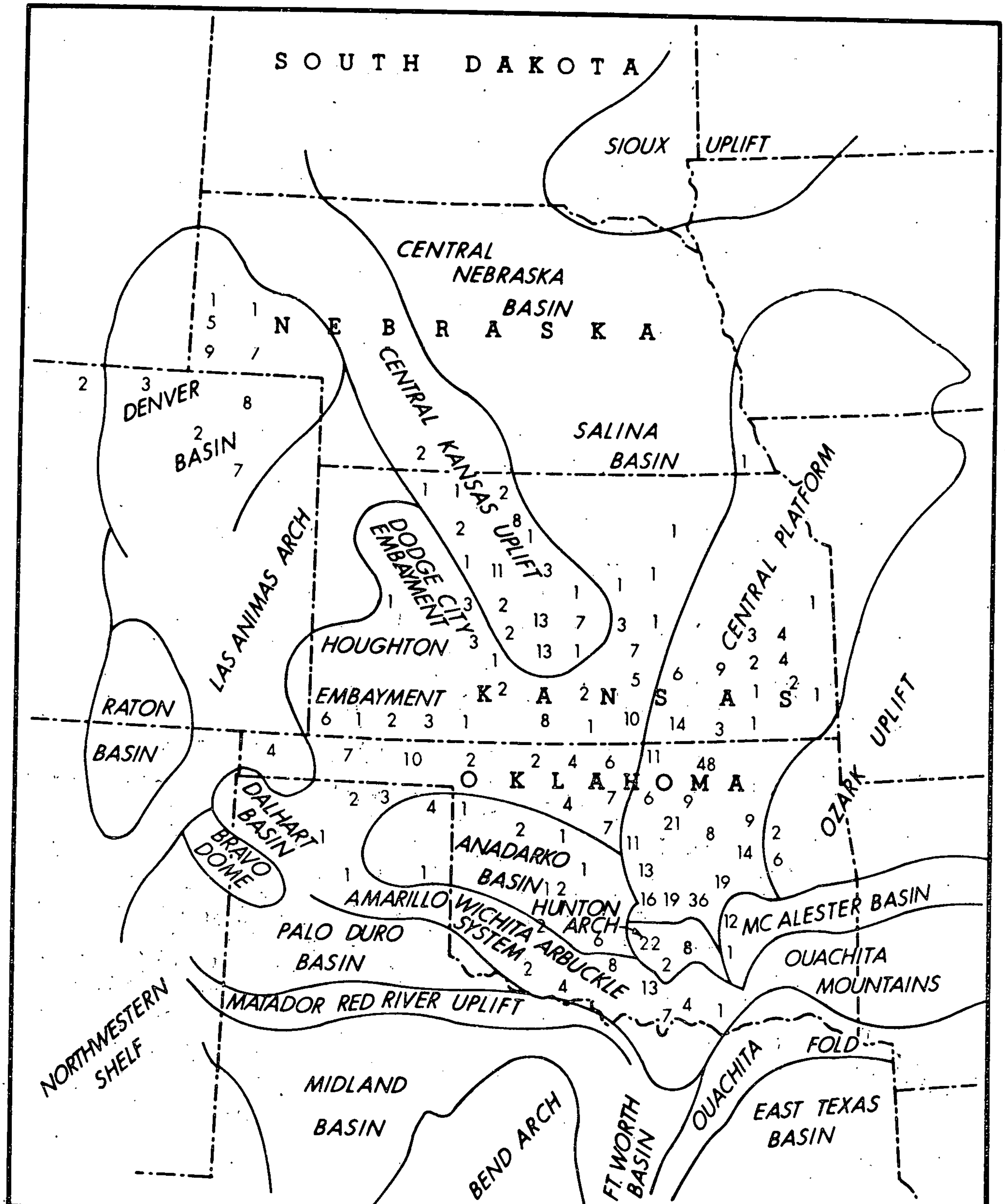
The average daily rate of production by well was established for each field not eliminated in the preliminary screening. A frequency plot of the average production rate for 730 fields in the Mid-Continent region is shown in Fig. 29, which shows that over 70 percent of the fields produce an average of less than 10 barrels of oil per day per well. This same plot shows the number of fields for each rate category that had more than 200,000 barrels of annual production. Significantly, most of these fields are in the stripper category.

Another significant feature apparent from Fig. 29 is that the number of fields producing at an average rate of less than 2 BOPD is less than the number producing at an average rate of 2 to 4 BOPD. This implies that with stripper prices the average economic limit may be as low as 2 BOPD.

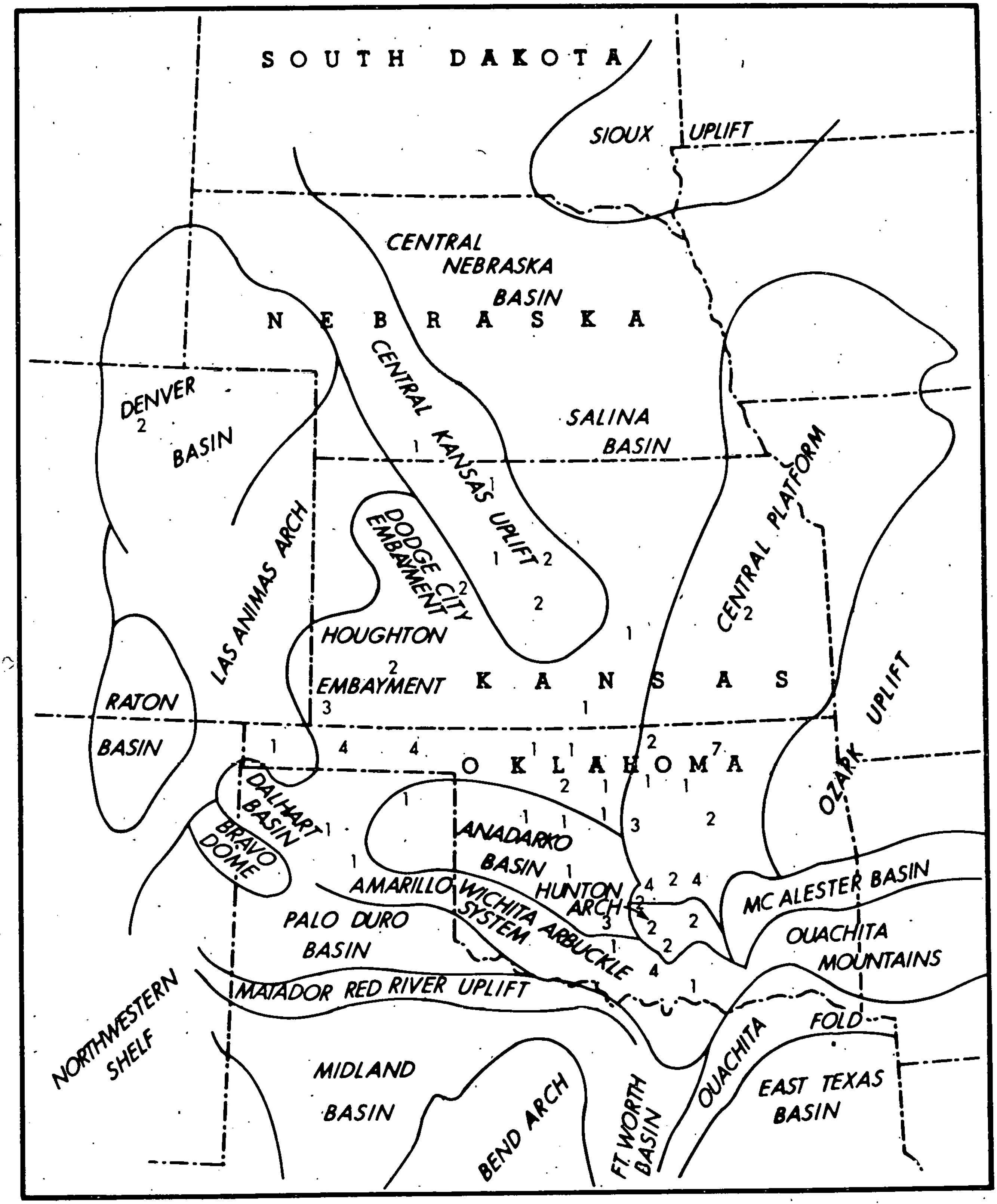
Location

The location of the 730 fields not eliminated by the minimal screening process described in the preceding section is shown in Fig. 30. These fields seem to be clustered in the southern Central Platform geologic province in central and northeastern Oklahoma. Similarly, the locations of the 88 fields in the selected subgroup (Fig. 31) exhibit significant clustering in the same region.


GRUY FEDERAL, INC.
FIGURE 29
RATE OF PRODUCTION ON A PER WELL BASIS OF 730 OIL FIELDS IN THE MID CONTINENT AREA.
Legend
FIELDS NOT STUDIED IN DETAIL
FIELDS SELECTED FOR DETAIL STUDY
NUMBER OF FIELDS IN THE PROJECT AREA
0
20
40
60
80
100
120
140
160
180
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
AVERAGE PRODUCTION RATE- BBL/DAY/WELL



LOCATION OF 730 POTENTIAL CANDIDATE FIELDS
BY COUNTY IN THE MID-CONTINENT REGION.
FIGURE 30



LOCATION OF 88 FIELDS SELECTED AS A SUB GROUP
BY COUNTY IN THE MID-CONTINENT REGION.
FIGURE 31

Waterflooding

Of the 88 fields selected for detailed study, 64 had waterflood projects in at least one sandstone reservoir. Information on water and oil production was available from commercial sources on 155 different unit operations in these floods. From these, the distribution of current water-oil ratio with current production was constructed (see Fig. 32). It is apparently log normal. About 2 percent of current production is being obtained from projects where the water-oil ratio is greater than 100.

A distribution curve relating the current water-oil ratio to the projected ultimate waterflood production was also contstructed (see Fig. 33). For individual project reserve estimation, economic limits were assumed to be either a production rate of 1 BOPD per well or an overall WOR of 100, whichever condition was first attained under a 20 percent annual decrement of these features. As Fig. 33 shows, almost half the waterflood ultimate production from these projects is expected from fields where the current water-oil ratio is 40 or more.

Porosity and Permeability

The distribution of 54 average porosity values -- all that could be found for the 332 sandstone reservoirs in the selected group -- is given in Fig. 34. Plotted on Fig. 35 is the distribution of the 632 porosity values contained in the Petroleum Data Service file on any sandstone oil reservoir in the project area. These two plots show that the porosity of the sandstone reservoirs in the selected subgroup is 16.5 percent, slightly higher than the larger sample. However, the subgroup seems to be representative of the larger group.

The distribution of all average permeabilities found for the selected subgroup (53) is plotted on Fig. 36. The range is from about 5000 md to about 2 md, with a median value of about 40 md.

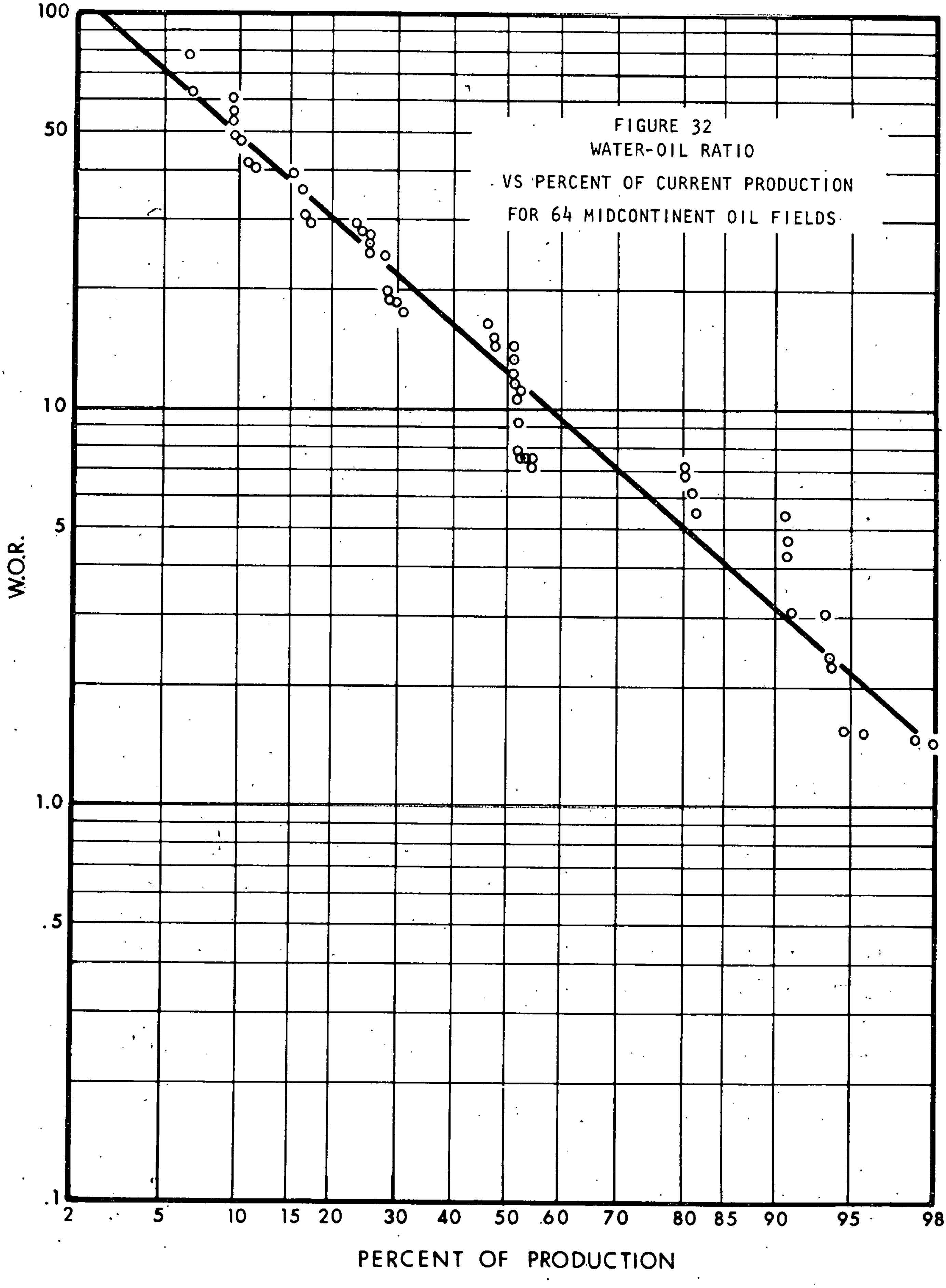


FIGURE 32
WATER-OIL RATIO
VS PERCENT OF CURRENT PRODUCTION
FOR 64 MIDCONTINENT OIL FIELDS
100
50
10
5
1.0
.5
.1
W.O.R.
2
5
10
15
20
30
40
50
60
70
80
85
90
95
98
PERCENT OF PRODUCTION

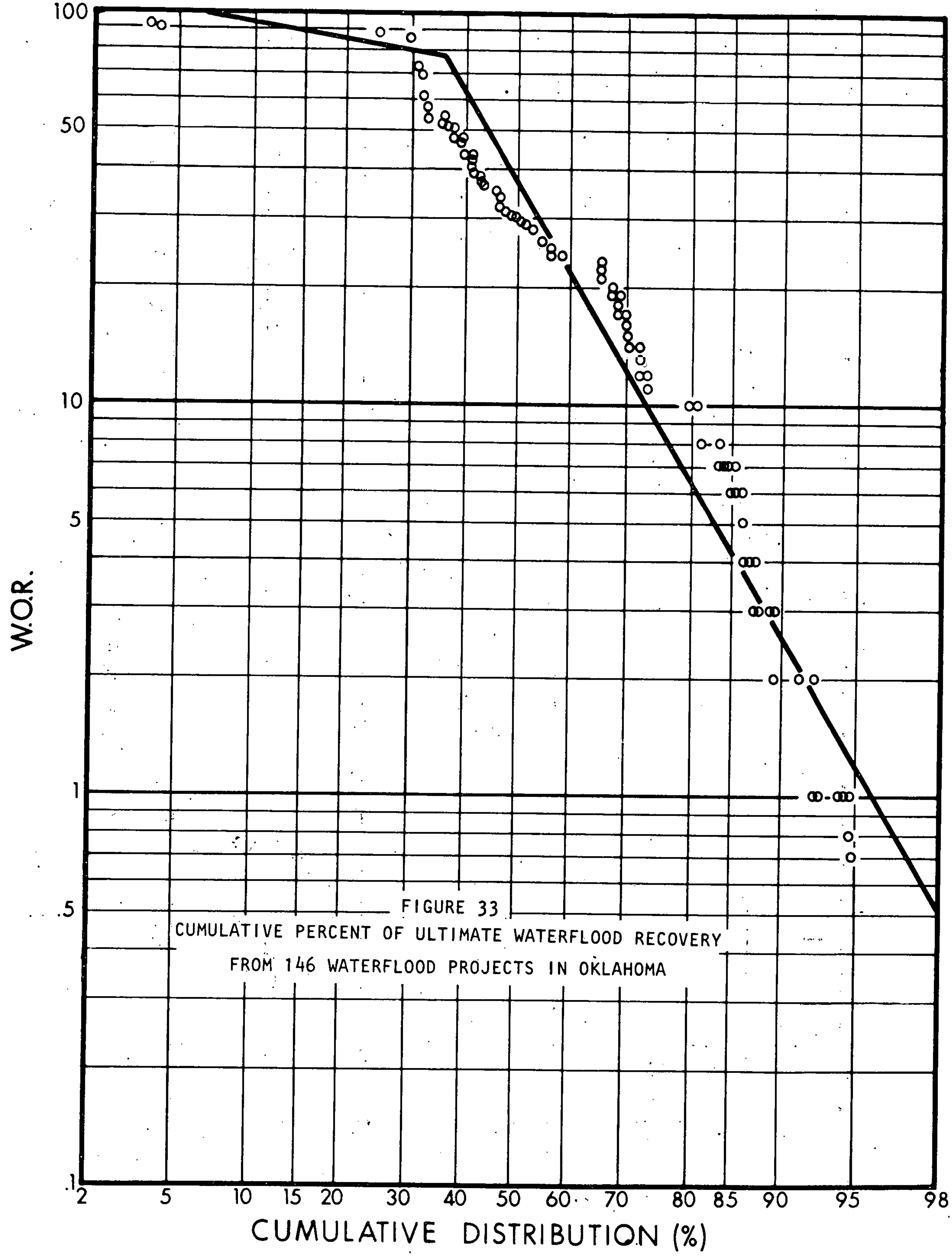


FIGURE 33
CUMULATIVE PERCENT OF ULTIMATE WATERFLOOD RECOVERY
FROM 146 WATERFLOOD PROJECTS IN OKLAHOMA

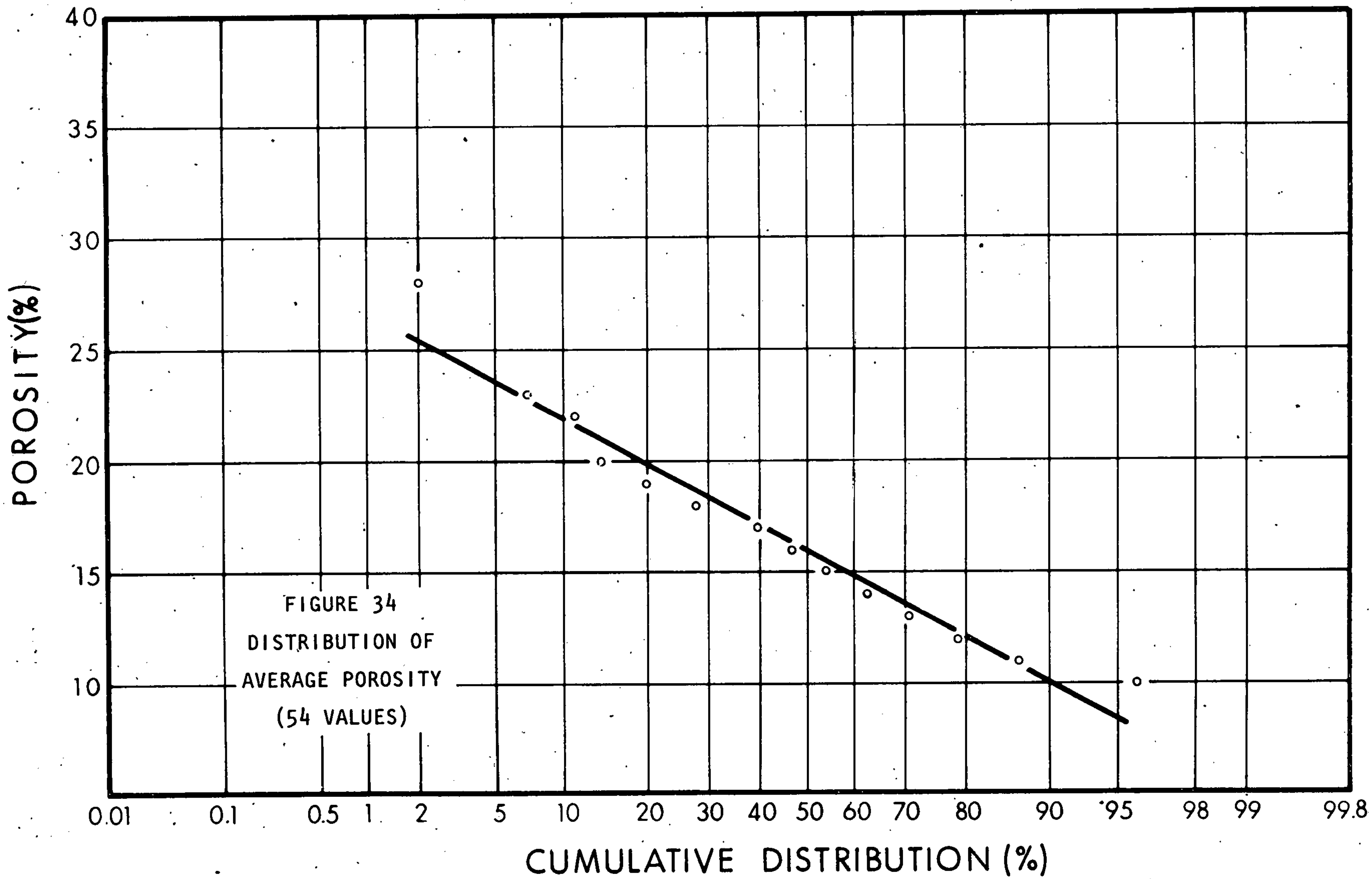


FIGURE 34
DISTRIBUTION OF
AVERAGE POROSITY
(54 VALUES)

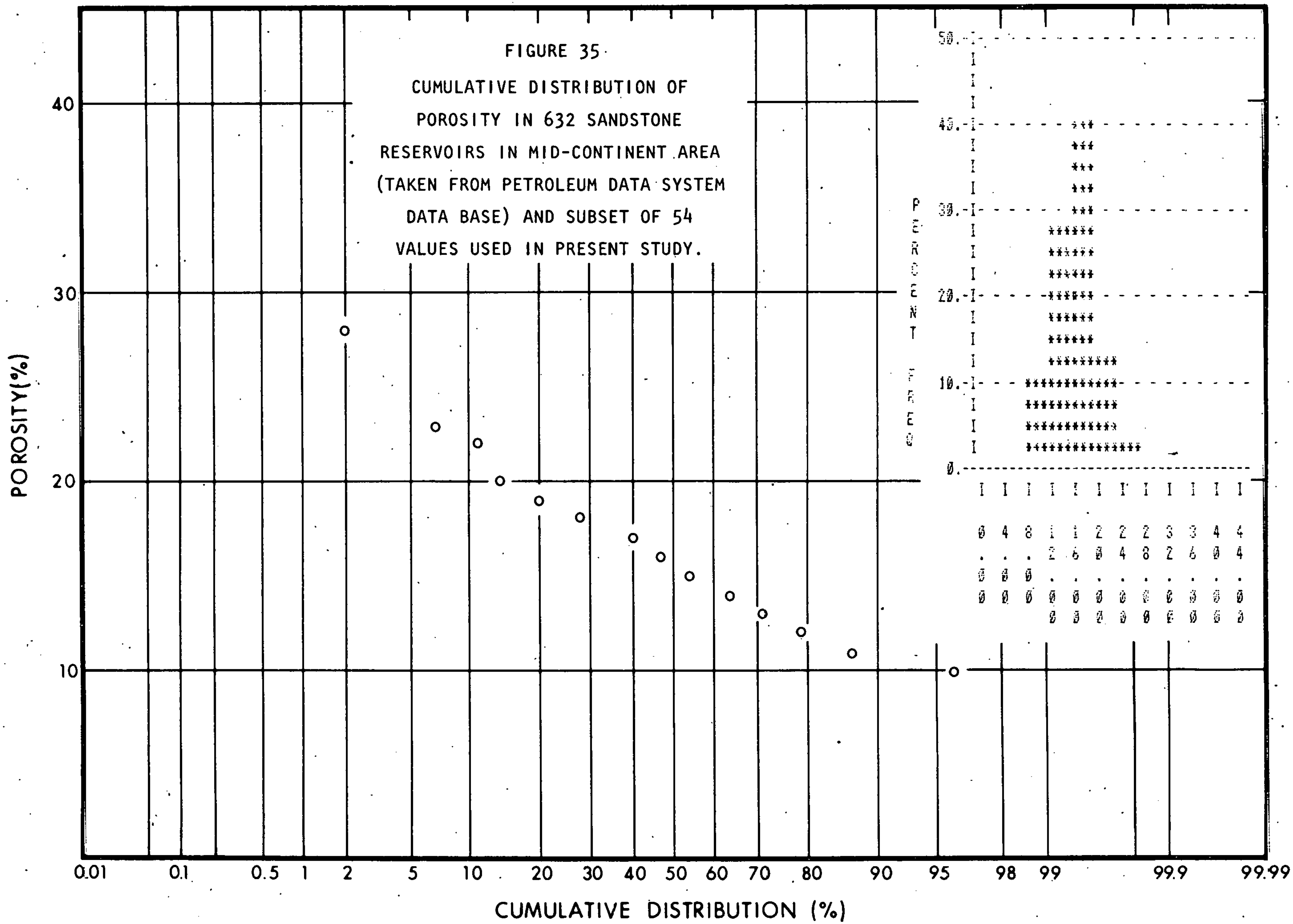


FIGURE 35

CUMULATIVE DISTRIBUTION OF POROSITY IN 632 SANDSTONE RESERVOIRS IN MID-CONTINENT AREA (TAKEN FROM PETROLEUM DATA SYSTEM DATA BASE) AND SUBSET OF 54 VALUES USED IN PRESENT STUDY.

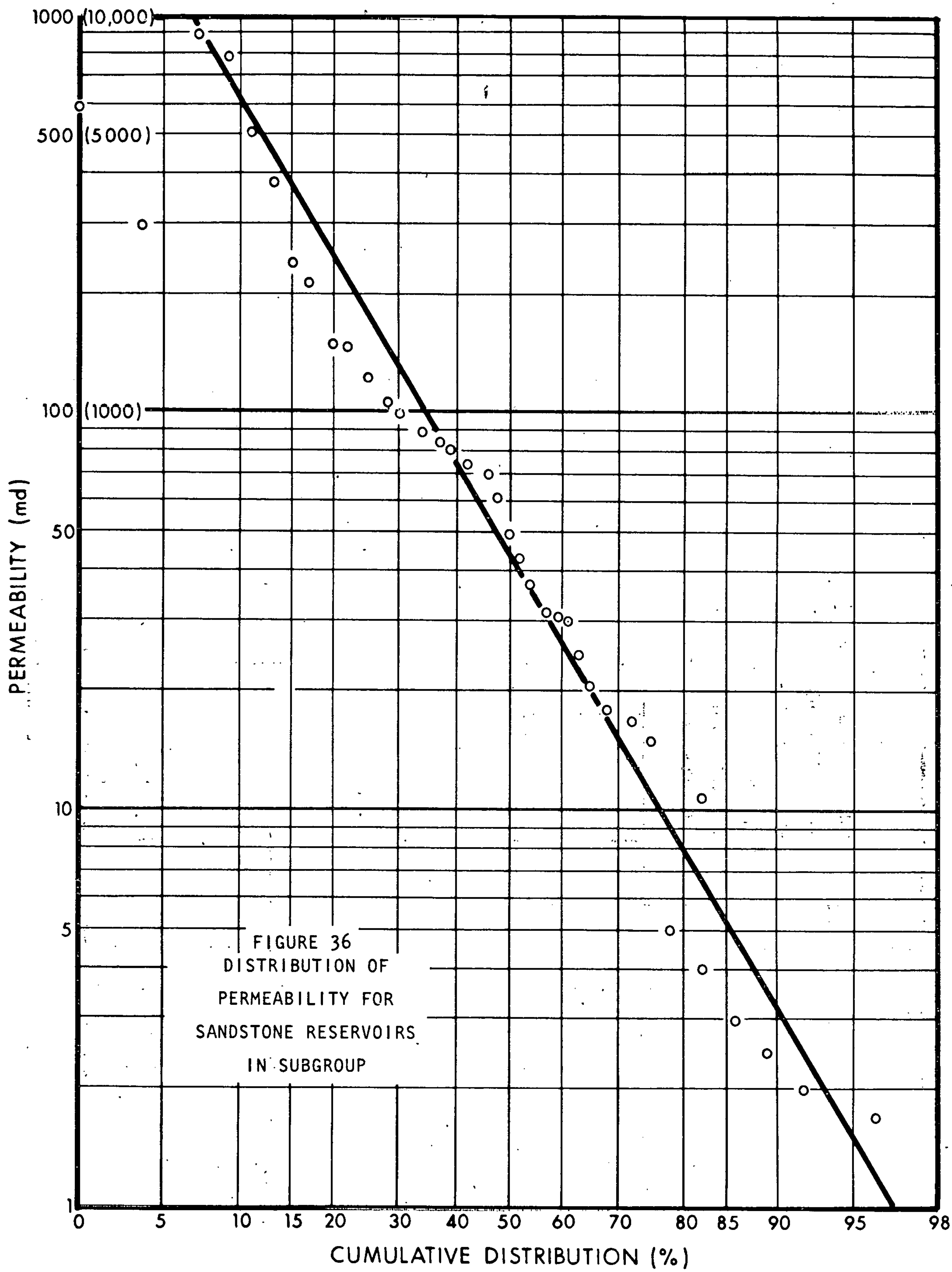


FIGURE 36
DISTRIBUTION OF PERMEABILITY FOR SANDSTONE RESERVOIRS IN SUBGROUP

Koepf (1962) reported average core analysis data based on a large number of measurements by Core Laboratories on cores from 40 producing formations in Oklahoma and Kansas, including 19 sandstone formations. Data from these 19 formations are reproduced in Table 9.

Pertinent observations on the porosity and permeability measurements included in Table 9 are:

1. The aggregate average values of 60 md permeability and 16.2 percent porosity agree very closely with the values of 40 md and 16 percent indicated by the present study.

2. For every case where permeability values (K_{90}) were measured in a direction perpendicular to apparent fracture orientation, lower average permeability values were obtained. The ratio of the average K_{90} to average K for individual formations ranged from 0.01 to 0.4, with 8 of the 11 values being less than 0.2. This may suggest widespread fracturing, or at least incipient fractures.

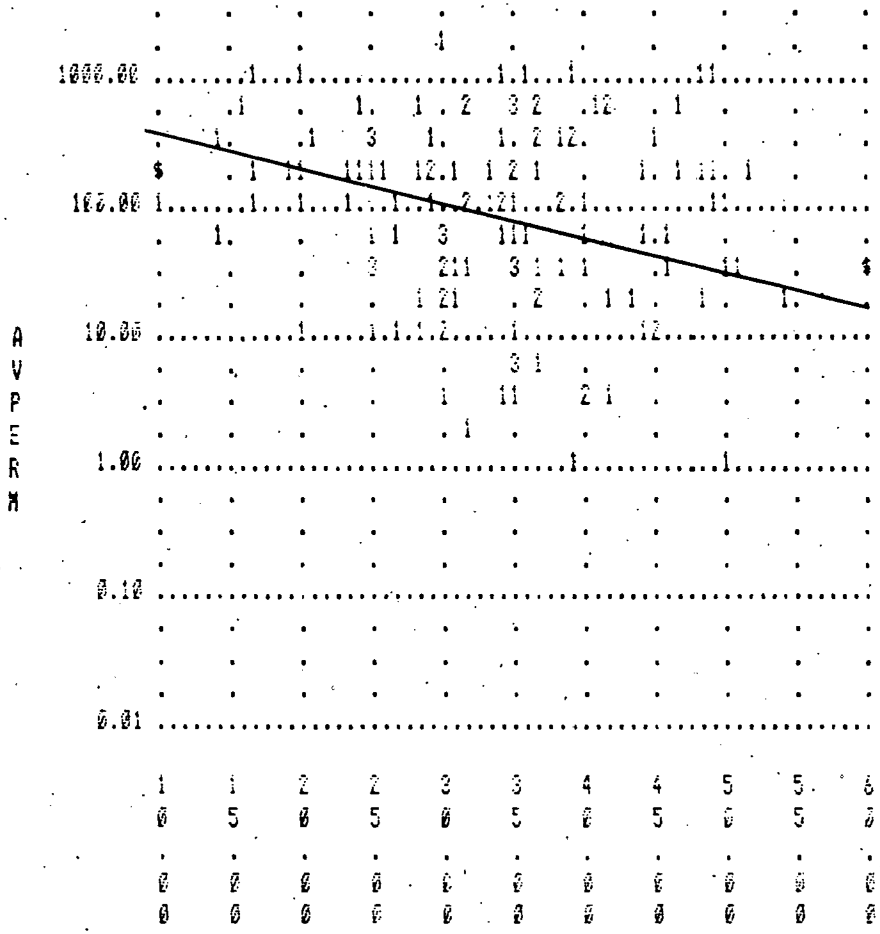
A plot of the average porosity vs. average permeability of 291 sandstone oil reservoirs in the study area for which both values were available on PDS records is given as Figs. 37a and 37b. Although the values have a wide range, higher average permeabilities tend to be found with higher porosities. The plot also reveals that associating the average porosity of approximately 16 percent with an average permeability of 40-60 md is consistent with the observed data.

Water and Oil Saturations

Also listed in Table 9 are initial oil saturations and connate water saturations for the 19 formations. The water saturation values from which this summary was derived were calculated in some cases from empirical correlation of core total water with connate water measurements from other sources

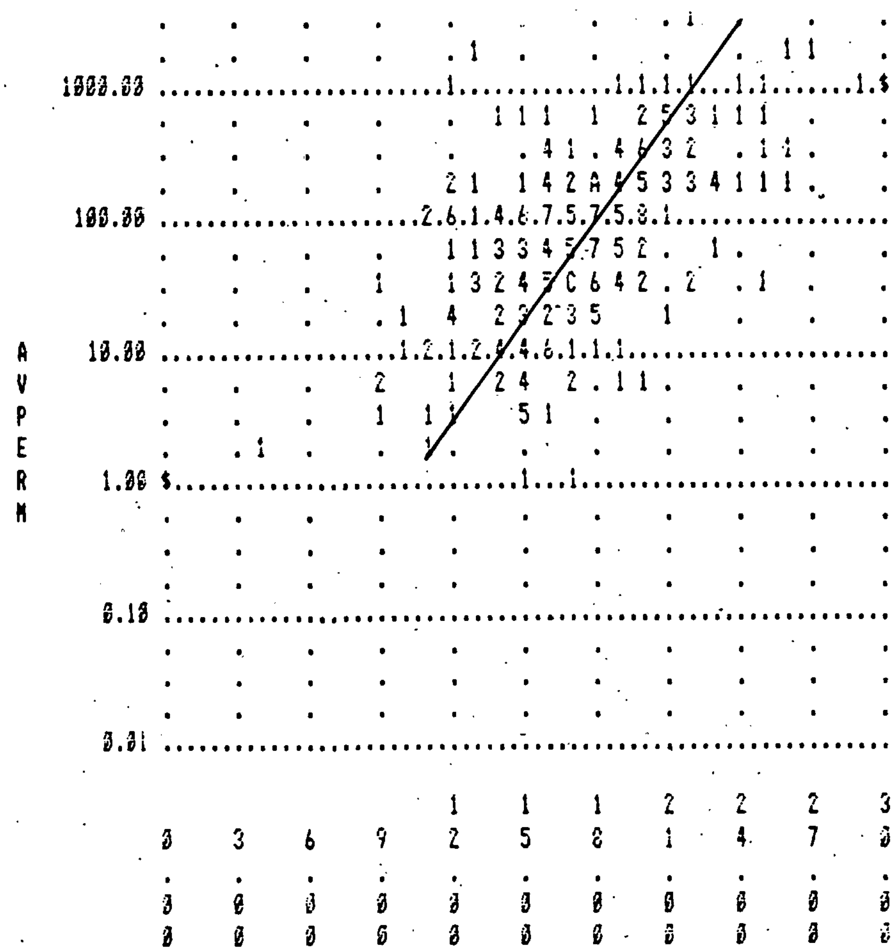
AVERAGE POROSITY, PERMEABILITY AND WATER SATURATION OF

MID CONTINENT SANDSTONE RESERVOIRS



WATER SATURATION

FIGURE 37A



POROSITY

FIGURE 37B

TABLE 9

AVERAGE RESERVOIR PROPERTIES OF OKLAHOMA-KANSAS SANDSTONES FROM CORE ANALYSES (FROM KOEPF, 1962)

Formation	Average Production Depth, ft	Average Thickness, ft	Average Permeability K, md	Average Permeability K_{90}, md	Average Porosity, %	Average oil Saturation, %	Average Connate Water	Average Gravity °API
Atoka	2600	7.8	144	1.7	14.5	20.7	37	38
Bartlesville	1500	14.0	32.7	1.5	17.8	18.2	40	34
Booch	2600	8.8	19.3	---	15.6	21.5	37	35
Burbank	2800	17.3	8.64	---	15.7	15.3	43	39
Chester	5700	8.6	9.11	0.21	10.1	19.1	33	40
Cleveland	3200	13.4	15.4	1.85	15.2	13.1	44	42
Deese	5200	11.7	62.8	1.10	17.4	20.4	33	32
Hoover	2000	11.9	288	---	19.7	16.0	35	42
Layton	2900	10.3	54.1	23.3	17.8	15.3	41	37
Misner	4300	10.6	89.7	0.62	11.9	14.8	38	42
McLish	8100	12.2	39.0	---	11.0	13.2	31	38
Morrow	5700	9.8	117	23.1	14.6	15.1	35	40
Peru	1200	12.4	20.8	---	18.7	14.7	44	36
Prue	3100	14.6	22.6	---	17.0	16.9	38	42
Purdy	4500	14.8	182	179	16.7	20.0	29	41
Reagan	3600	11.0	255	---	13.3	14.2	31	38
Redfork	3100	10.5	14.2	---	16.2	16.9	41	37
Skinner	3200	9.2	20.6	3.30	15.3	20.1	38	36
Strawn	3500	12.4	58.1	---	16.8	15.1	41	40
Tonkawa	4800	8.7	98.6	15.0	18.4	12.5	38	43
Tucker	2200	7.6	36	---	15.6	16.0	38	36
Wayside	800	10.8	22.2	---	18.6	18.6	47	35
First Wilcox	4900	10.0	91.3	---	12.0	11.7	31	42
Second Wilcox	6500	11.3	214	---	12.4	10.2	34	40

and in some cases from capillary pressure data. These were selected to represent "irreducible values," i.e., from depths considered to be above any transition zone, where present.

The oil saturation values in Table 9 are core saturation values measured without correction for shrinkage and expulsion. Koepf, in material included in a recent IOCC publication (1978), suggests use of a correction factor equal to 1.15 times formation volume factor as a general average correction from routine core oil saturation to in-situ saturation. Assuming an average formation volume factor of 1.2, this suggested correction factor becomes 1.4. Craig (1971) suggests a factor as high as 2.0. Applying this range of factors to the average core oil saturation results in a range of corrected values of 0.24 to 0.34.

Empirical relationships between permeability, porosity, and water saturation have been the subject of many publications since the early 1950's. Utilizing an average porosity vs average permeability plot and a plot of average initial water saturation vs average permeability (Fig. 37a), an empirical relation can be derived relating observed average porosity, permeability, and water saturations of Mid-Continent sandstone reservoirs:

$$K = \frac{C\phi^3}{Sw^2} \qquad \text{(after Wylie \& Rose, 1950)}$$

where $C = 1543.21$ for these samples.

This correlation is strictly empirical and, as Fig. 35 shows, there is considerable spread in the data.

Other Features

Certain features of oil reservoirs are critically important to the polymer waterflood process, yet are largely unavailable from the technical literature, namely mobility ratios and permeability variances. The values used to estimate the ranges of these reservoir features for the purposes of this study, as well as design features employed to date, were drawn almost exclusively from one paper (Jewett and Schurz, 1970).

Permeability Variation

A plot of the distribution of permeability variation (V_k) in the fields where polymer floods have been attempted is given in Fig. 38. The range of values of V_k is from 0.95 to 0.4 with an average of about 0.67.

Resistance Factors

Also on Fig. 38 is a plot of the distribution of resistance factors attributable to the polymer design employed in these projects. They range from 4 to 15 with an average of about 8.5. The resistance factor is due in part to the rock and in part to the polymer, and consequently can be designed, within limits.

Initial Mobile Oil Saturation

The distribution of initial mobile oil saturations and irreducible water saturations is given in Fig. 39. The mobile oil saturation ranges from 45 percent to 18 percent with an average of 30. The irreducible water saturations range from 51 percent to 17 percent, with an average of about 30 percent.

Mobility Ratio

The mobility ratio of water to oil in these projects has ranged from less than 1 to about 40, with an average value of about 6. This distribution is plotted in Fig. 40. Also plotted in Fig. 40 is a design feature which is a combination of slug concentration and slug size (ppm x % pore volume). This factor has ranged from 200 to less than 1. The mean value for these projects is about 60.

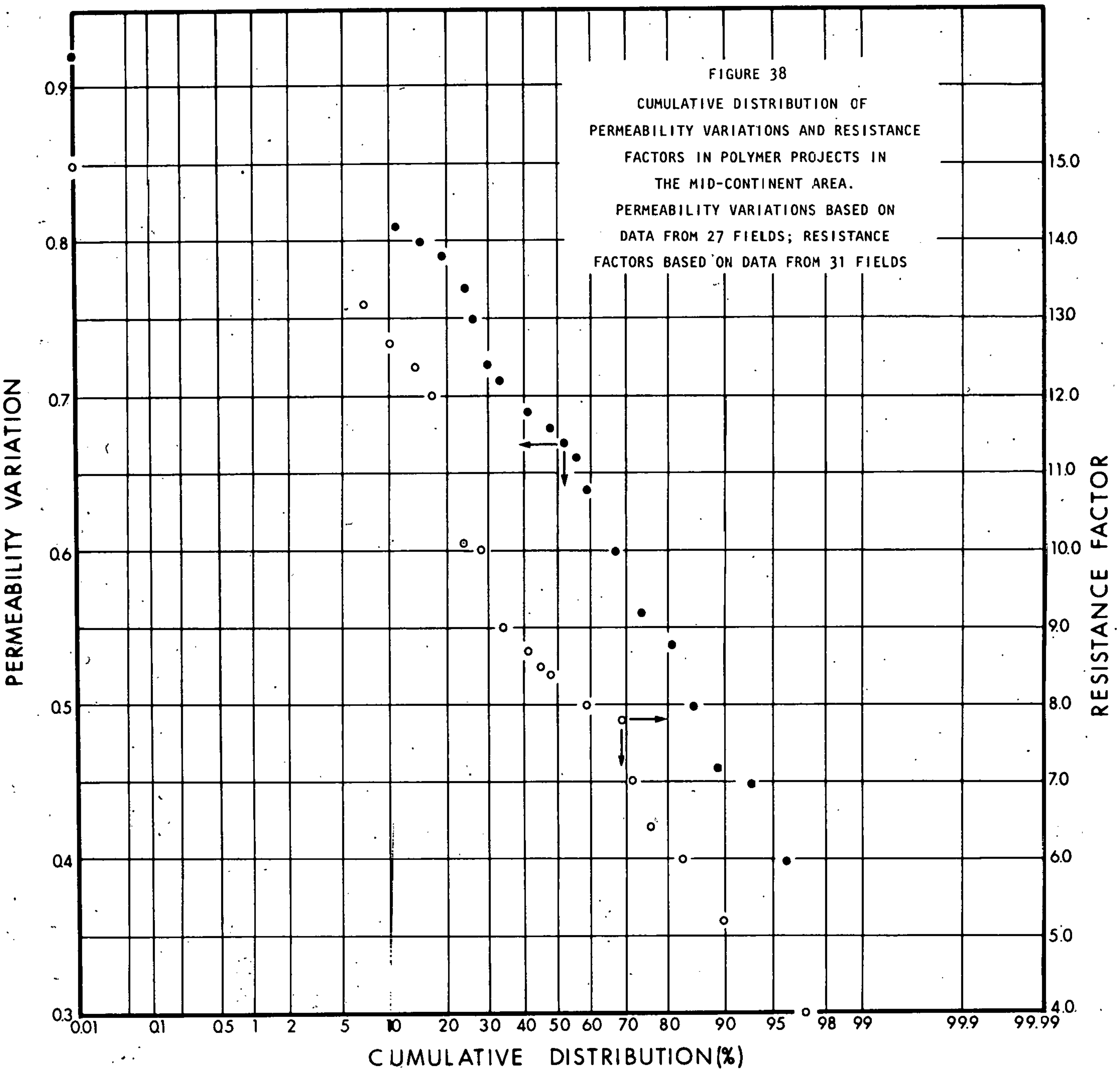


FIGURE 38

CUMULATIVE DISTRIBUTION OF PERMEABILITY VARIATIONS AND RESISTANCE FACTORS IN POLYMER PROJECTS IN THE MID-CONTINENT AREA. PERMEABILITY VARIATIONS BASED ON DATA FROM 27 FIELDS; RESISTANCE FACTORS BASED ON DATA FROM 31 FIELDS

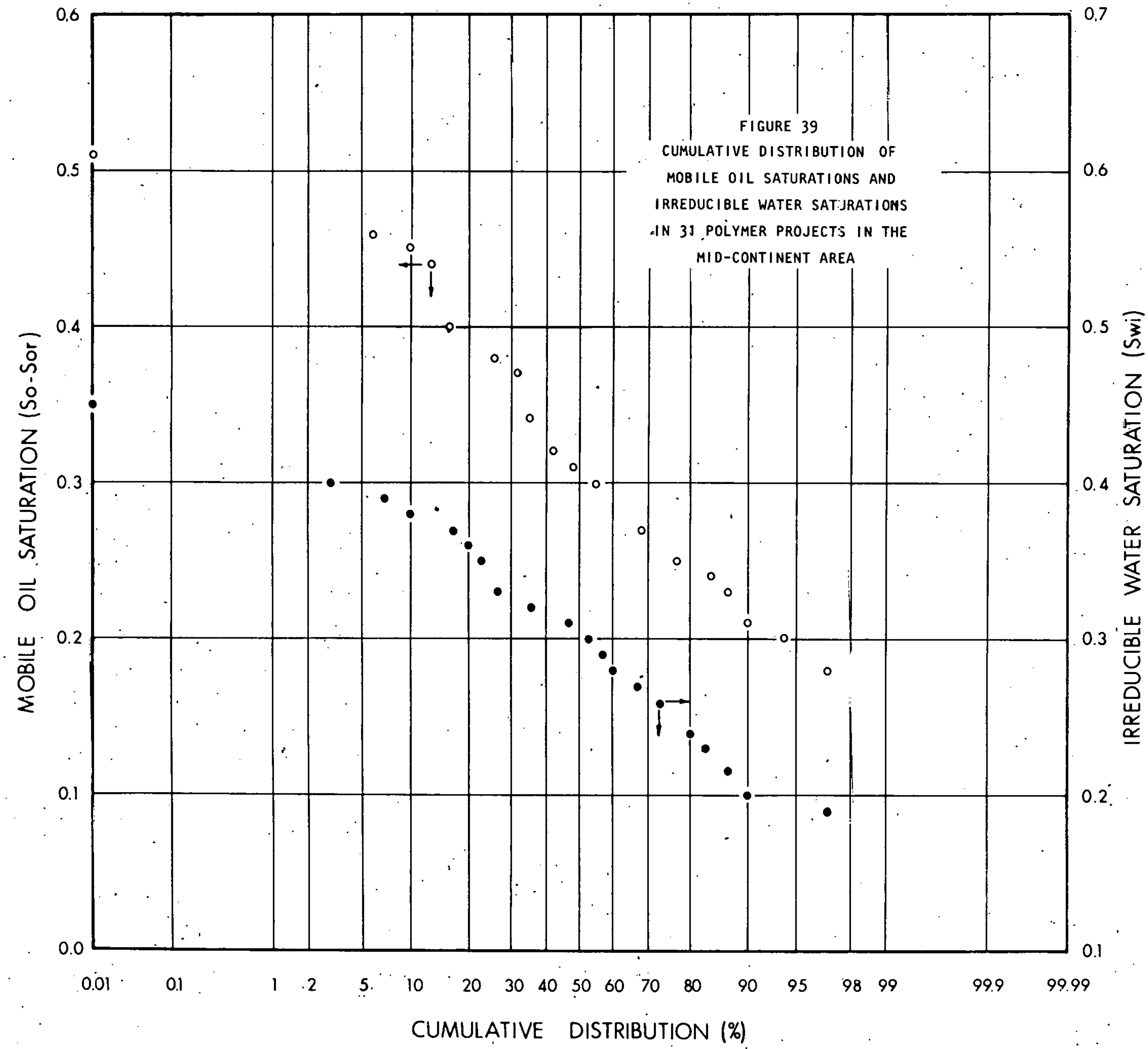


FIGURE 39
CUMULATIVE DISTRIBUTION OF MOBILE OIL SATURATIONS AND IRREDUCIBLE WATER SATURATIONS IN 31 POLYMER PROJECTS IN THE MID-CONTINENT AREA

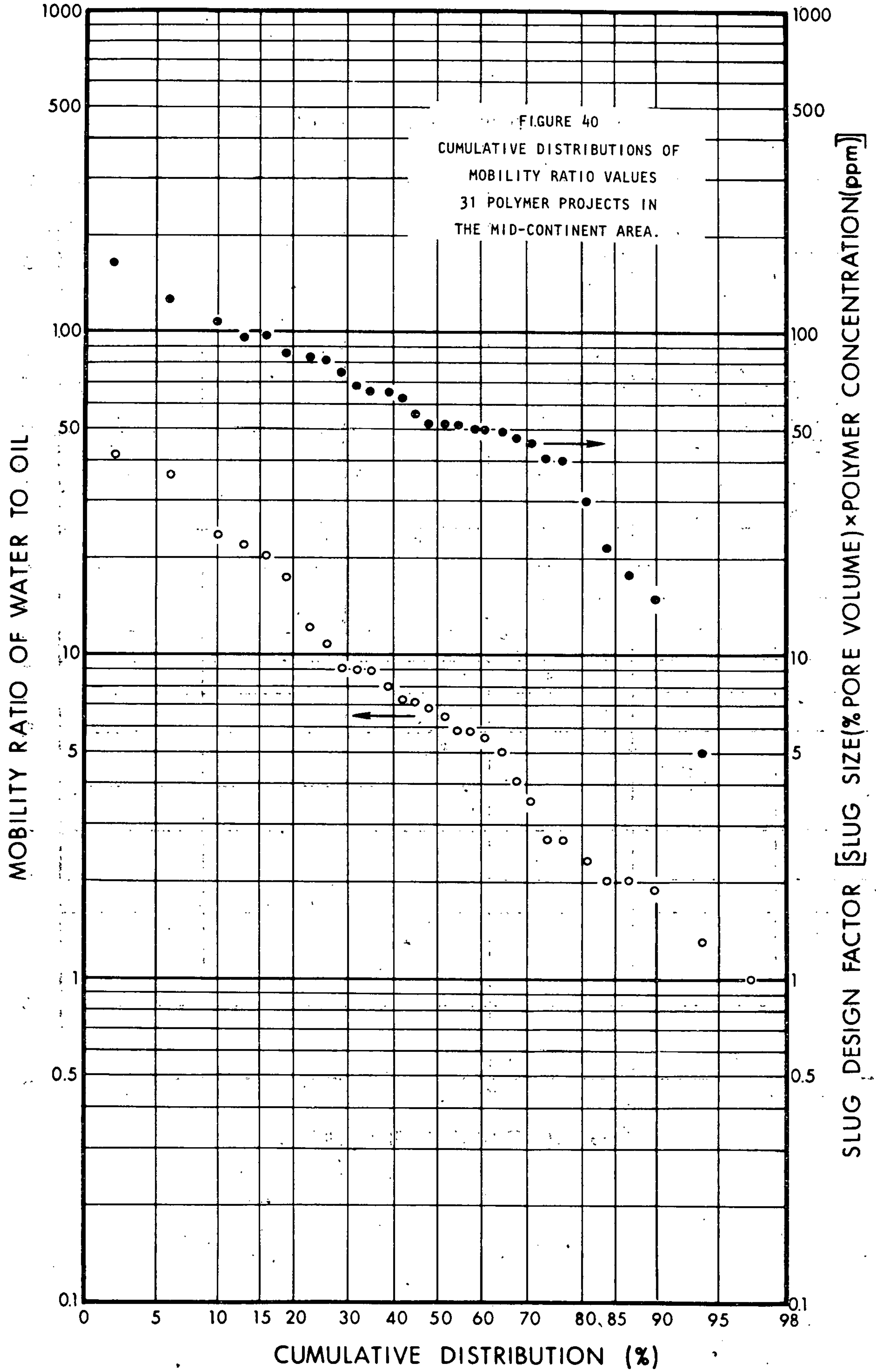


FIGURE 40
CUMULATIVE DISTRIBUTIONS OF
MOBILITY RATIO VALUES
31 POLYMER PROJECTS IN
THE MID-CONTINENT AREA.
MOBILITY RATIO OF WATER TO OIL
SLUG DESIGN FACTOR [SLUG SIZE(% PORE VOLUME) × POLYMER CONCENTRATION(ppm)]
CUMULATIVE DISTRIBUTION (%)
1000
500
100
50
10
5
1
0.5
0.1
0
5
10
15
20
30
40
50
60
70
80
85
90
95
98

IV. ESTIMATE OF FUTURE INCREASED OIL PRODUCTIVITY

Lacking essential evaluation data for enough reservoirs to permit estimation of regional potential by a field sampling approach, the alternate method adopted was to estimate (1) the total polymer oil resource from regional statistics, (2) the fraction of this resource occurring in reservoirs that might be considered polymer flooding candidates, and (3) an average recovery efficiency applicable to this target.

Estimate of Regional Polymer Oil Resource

The regional polymer oil resource (total accessible mobile oil not economically recoverable by conventional waterflooding) in all active waterflood projects in the Mid-Continent area is estimated to be 1.7 billion barrels. This is based on a mobile oil volume remaining after conventional waterflooding equal to the ultimate volume recoverable by conventional flooding.

Estimate of Ultimate Recovery by Conventional Waterflooding

The following tabulation from API statistics shows the distribution of estimated original oil in place and estimated ultimate recovery from sandstone reservoirs in the study region as of December 31, 1977.

Estimates for Sandstone Only

State or District	Original Oil in Place Bbl (M)	Original Oil in Place % Region	Ultimate Recovery Bbl (M)	Ultimate Recovery % OOIP
Colorado	3,997,596	9	1,386,750	34.7
Kansas	4,349,316	10	1,541,502	35.4
Nebraska	1,277,012	3	361,440	28.3
Oklahoma	33,660,217	76	11,477,888	34.1
Tex. Dist. 10	930,137	2	169,966	18.3
Regional Total	44,214,278		14,937,546	

The following breakdown of regional total by type of production mechanism is a distribution consistent with our estimate of regional ultimate waterflood recovery.

Equivalent Breakdown of Regional Total by Type of Production Mechanism

	Original Oil in Place		Ultimate Recovery	
	Bbl (M)	% Region	Bbl (M)	% OOIP
Fields with no waterflood	26,700,000	60	8,250,000	31
Fields with waterflood	17,500,000	40	6,650,000	38
Primary Recovery			3,850,000	(22)
Waterflood Recovery			2,800,000	(16)
Active			1,700,000	
Abandoned			1,100,000	

It will be noted from the API statistics that Oklahoma contains 76 percent of the estimated regional total original oil in place and 77 percent of the estimated ultimate recovery. For this reason, and because of the unavailability of better statistics, an estimate of ultimate waterflood recovery was developed for Oklahoma and extrapolated to the total region on the basis of Oklahoma ultimate 0.76 x regional ultimate.

Ultimate waterflood recovery from Oklahoma was estimated using two approaches, (1) utilizing historical statistics on primary production, secondary recovery, and the number of active projects reported by the Bureau of Mines, and (2) an analysis of production statistics on 148 waterflood projects included in the group of 88 fields selected for intensive data search under Section III.

Bureau of Mines Information Circulars 8455 and 8734

In Bureau of Mines Information Circular 8734 (1977), estimated annual production by enhanced oil recovery methods for 1946 through 1974 was reported by major producing states. Circular 8455 (1970) estimated that 90 percent of secondary recovery in Oklahoma was derived from waterflooding.

Reported EOR production statistics for key years and our analyses of waterflood production and reserves are summarized in the following:

Key Year	Estimated Annual Production - Oklahoma: Total EOR	Barrels (M): Waterflood @ 0.9 x EOR
1931 (1)		Assumed nil
1946 (2)	13,132	11,819
1970 (3)	110,903	99,813
1974 (4)	90,383	81,345
1978 (5)	---	60,000

Time Period	Estimated Total Waterflood Production-Oklahoma Barrels (M)
1946 thru 1974 (6)	1,500,000
1931 thru 1945 (5)	100,000
1975 thru 1978 (5)	270,000
Est. Cumulative to 1/1/79	1,870,000
Est. Reserves 1/1/79 (7)	360,000
Est. Ultimate	2,230,000

NOTES

(1) Year first waterflood project commenced in Oklahoma.
(2) First year of estimated production statistics.
(3) Peak waterflood production.
(4) Last year of estimated production statistics.
(5) Gruy estimate by extrapolation.
(6) Summation of annual estimates.
(7) Based on estimated reserves/annual production ratio (R/P) = 6.

One other source of support for the waterflood reserve estimates is included in estimates reported in Twentieth Century Petroleum Statistics, 1977, by DeGolyer and MacNaughton. The estimate of secondary recovery reserves at stripper well locations in Oklahoma was 374 million barrels as of December 31, 1975, based on IOCC and National Stripper Well Association information. Stripper wells at that time comprised about 80 percent of the total producing wells in the state and accounted for about 48 percent of the state's total production. These wells would be expected to contribute a higher percentage of secondary recovery production. Assuming they represent 65 percent of the total secondary recovery reserves, the indicated total for the state is 374/0.65 = 575 million barrels. Correcting for waterflood portion at 90 percent of total secondary recovery results in an estimated waterflood reserve at January 1, 1976, of 0.9 x 575 = 518 million barrels. Deducting estimated waterflood production of 195 million barrels for 1976 through 1978 reduces the apparent reserves at January 1, 1979, to 323 million barrels before provisions for extensions and additions during 1976 through 1978. This is in close agreement with the estimated figure of 360 million barrels as of January 1, 1979, derived above.

Bureau of Mines Information Circular 8455 also reported the number of active waterflood projects in the state as 61 in 1942, 107 in 1949, and 955 in 1964.

From commercial reports prepared by Petroleum Information Corporation for the period July through December 1977, about 1300 waterflood projects are estimated to have been active in 1978.

Utilizing these statistics, and estimating abandonments based on an average waterflood life expectancy of 12 years before 1960 increasing to 16 years in 1978, the cumulative total number of projects initiated through 1978 is estimated to be about 2100.

Assuming the 1300 currently active projects will have a project average ultimate waterflood recovery expectancy equal to the average for the 2100 total, the estimated ultimate from these projects is 1300/2100 x 2.23 billion, or 1.38 billion barrels.

From statistics reported by the API, sandstone reservoirs in Oklahoma contain 88 percent of the estimated original oil in place in all reservoirs in the state and were expected to yield 91 percent of the ultimate recovery as of December 31, 1977. Applying a 90 percent factor to the above-derived estimate of statewide ultimate waterflood recovery from all reservoirs results in an estimated ultimate from sandstone reservoirs of 1.24 billion barrels. The estimated reserve as of January 1, 1979, is 0.9 x 360 = 324 million barrels.

Analysis of 148 Waterflood Projects

Data from commercial sources for the group of waterflood projects described in Section III show a total cumulative production of 459 million barrels since the date of unitization. Arbitrarily reducing this by a factor of 0.80, to correct for primary reserves at date of unitization, leaves an adjusted waterflood cumulative of 370 million barrels. Total annualized production rate for these projects based on December 1977 pipeline runs was 18.5 million barrels. Estimated reserves based on R/P = 6 are 111 million barrels, for an estimated ultimate of 481 million barrels. The sum of the individual project ultimates developed in preparation of Fig. 33, similarly corrected, is 109 million barrels.

The distribution of project ages for this study group is the same as that for all currently active Oklahoma projects. For example, approximately one-half of the projects in each group were begun before 1965. Assuming they are at the same average stage of depletion, the relative ultimate recoveries are estimated to be proportional to the remaining reserves. On this basis the indicated total state ultimate waterflood recovery is 481 x 324/111 = 1.40 billion barrels.

The agreement between this figure and the 1.24 billion developed in the preceding section appears to justify use for this study of 1.3 billion barrels as the estimated ultimate waterflood recovery from active sandstone waterfloods in Oklahoma.

Based on API statistics for December 31, 1977, Oklahoma contained 76 percent of the original oil in place in sandstone reservoirs in the total study region. Based on Twentieth Century Petroleum Statistics, Oklahoma secondary reserves at stripper well locations also represented 76 percent of the regional total as of December 1975. Applying this factor to the estimate of 1.3 billion barrels ultimate waterflood recovery from currently active sandstone waterfloods in Oklahoma results in an estimate for the region of 1.72 billion barrels. Assuming an average remaining mobile oil volume equal to waterflood ultimate, this figure also represents the regional resource for mobility control processes.

Target in Candidate Reservoirs

From Fig. 33 it is apparent that about 40 percent of the estimated waterflood ultimate in currently active projects is in projects with producing water-oil ratios of 60 to 100. Eliminating this portion as candidates for polymer application reduces the above figure to 1.03 billion barrels.

From economic considerations discussed in Section III, the economic potential for polymer flooding of the average Mid-Continent sandstone waterflood project would not justify assumption of the risks involved, at current prices and technology. Any immediate application of significant scope would be expected to be limited, therefore, to selected prospects having better than average potential. These are judged to represent no more than 20 to 30 percent of the ultimate recovery represented by all those projects with current producing water-oil ratios less than 60. This would be equivalent to projects with estimated ultimate waterflood recoveries totaling 200 to 300 million barrels.

Assuming a mobile oil target remaining after conventional waterflooding equal to the waterflood ultimate, the immediate target for mobility control process (at 100 percent realization) is estimated at 200 to 300 million barrels. Since this potential is conceptually in projects with better than average qualifications, we have assumed recovery efficiency factors (Fig. 25) applicable to this group as follows: $F_1 = 0.5$, $F_2 = 0.7$, $F_3 = 0.8$. Factors F_1 and F_3 reflect basically more favorable reservoir and fluid parameters and a minimum of adverse conditions. Factor F_2 is also higher than the average (0.64) applicable to all current waterflood projects with beginning water-oil ratios less than 60 from the correlation shown in Fig. 26. The application of these factors results in an aggregate polymer recovery efficiency of 28 percent for the mobile oil target in the select group, as compared to an aggregate efficiency of 12 percent for the average waterflood reservoir. Applying this factor to the target of 200 to 300 million barrels produces an estimated immediate potential of 56 to 84 million barrels. Allowing for future extensions and additions of as much as 15 to 25 million barrels, the estimate of ultimate potential for the region is 80 to 100 million barrels. However, it is expected that not all of this potential will be realized, for the following reasons:

1. The aggregate affect of the factors applied in developing of the above estimate of potential tends to produce a liberal end result.

2. The potential will decrease with time because it is sensitive to the extent of prior flooding and because of the time lags expected in identifying, evaluating, and effecting projects.

3. The potential decreases with improved conventional waterflooding economics or efficiency. Such improvements can accrue through improved crude oil prices or application of less expensive waterflood upgrading techniques.

4. The estimate has not been discounted for application of other EOR processes in reservoirs where such processes may take precedence. This would most likely occur in the better candidate reservoirs.

Effects of Crude Oil Price and Improved Technology

The oil production performance model assumed for an average successful polymer application in a project of the same size (acre feet) as North Stanley is shown on Fig. 27 as Extension B. For this level of performance and with other conditions as exemplified by North Stanley, the calculated recovery and economic outcomes for specified crude price conditions are shown in Table 10 and Fig. 41.

For the base case crude price of $7 per barrel, the incremental recovery is 1,440,000 barrels. The indicated economic return would be marginal at best for the relatively high-risk investment involved.

Doubling the oil price results in an increase of 753,000 barrels in recovery attainable by waterflooding alone, with the incremental recovery by polymer reduced to 1,190,000 barrels. Despite the reduction in incremental oil, the higher crude price improves the potential economic reward, providing a more acceptable incentive for field applications of the process.

For the case of differential crude prices, the estimated total waterflood ultimate with polymer augment is the same (3,593,000 barrels) as for the previous case where the higher price is applied uniformly. However, the estimated recovery by conventional flooding alone is reduced by 753,000 barrels. This increment, therefore, becomes a credit to the polymer application and improves the apparent economics of the project. It will be noted from Fig. 41, however, that at the level of recovery performance attributed to the average successful project, the increase in apparent economic incentive by differential pricing as compared to uniform pricing is relatively small, particularly at discount rates of 15 percent and higher. This is because the net value of the incremental 753,000 barrels switched from conventional flooding to polymer flooding is received in the last years of life, and its present value at time zero becomes progressively smaller with increasing life (associated with higher recoveries) and with increasing discount rates.

TABLE 10

SUMMARY PERFORMANCE AND ECONOMIC OUTCOME
AVERAGE SUCCESSFUL POLYMER APPLICATION

	Discount Rate 0	15%	25%
Crude Oil Price = $7/bbl Applied Uniformly			
Recovery in thousands of barrels			
Est. Ultimate With Polymer	6440		
Est. Ultimate Without Polymer	5000		
Polymer Increment	1440		
Economic Success Ratio (ESR)	2.25	1.38	1.06
Crude Oil Price = $14/bbl Applied Uniformly			
Recovery in thousands of barrels			
Est. Ultimate With Polymer	6940		
Est. Ultimate Without Polymer	5750		
Polymer Increment	1190		
Economic Success Ratio (ESR)	4.48	2.79	2.14
Crude Oil Price = $7/bbl (WF Oil); $14/bbl (Polymer Oil)			
Recovery in thousands of barrels			
Est. Ultimate With Polymer	6940		
Est. Ultimate Without Polymer	5000		
Polymer Increment	1940		
Economic Success Ratio (ESR)	5.70	3.09	2.28

$$\text{ESR} = \frac{\text{P.V. incremental ongoing income, before taxes}}{\text{P.V. up-front costs}}$$

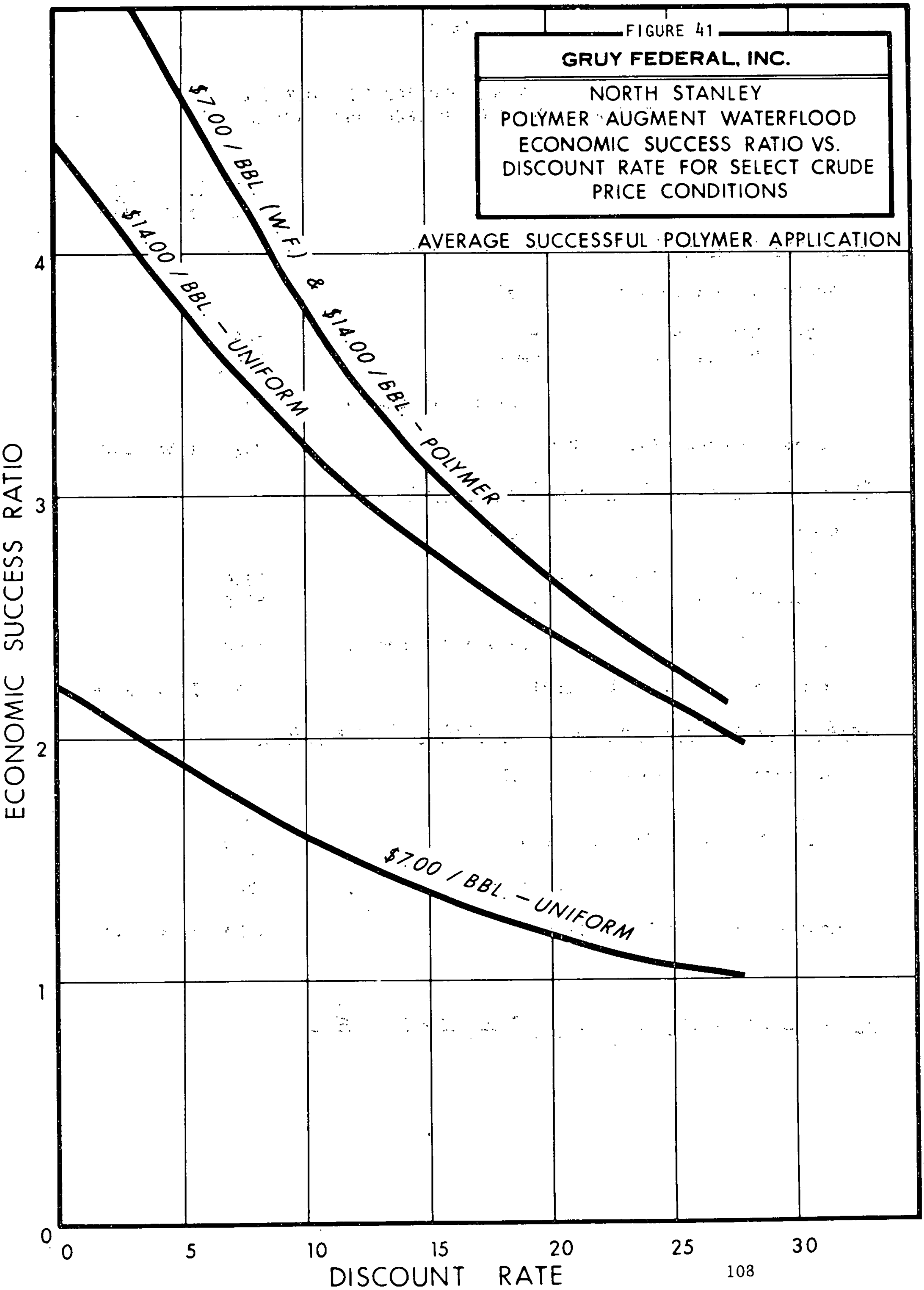


FIGURE 41
GRUY FEDERAL, INC.
NORTH STANLEY
POLYMER AUGMENT WATERFLOOD
ECONOMIC SUCCESS RATIO VS.
DISCOUNT RATE FOR SELECT CRUDE
PRICE CONDITIONS
AVERAGE SUCCESSFUL POLYMER APPLICATION
$7.00 / BBL. (W.F.) & $14.00 / BBL. - POLYMER
$14.00 / BBL. - UNIFORM
$7.00 / BBL. - UNIFORM
ECONOMIC SUCCESS RATIO
DISCOUNT RATE
0
1
2
3
4
0
5
10
15
20
25
30

Improvements in technology would be expected either to reduce unit costs of resources employed in the process or to increase recovery per unit of resource employed. Because chemical costs are a major factor, the principal areas for potential improvements would appear to be in reduced costs or improved effectiveness of the chemical employed. Opportunities for significant reduction in chemical cost are limited by the energy-intensive nature of the chemical production process. There may be opportunities for some improvement in effective use of chemicals in larger projects. Beneficial effects might be extended over longer time periods by extended injection of low concentration solution, and produced polymer solution might be recycled with small additions of make-up chemicals. No major technological breakthrough appears imminent, however.

From the above observations it is concluded that the magnitude of the probable effects of increased crude prices or improved technology is within the precision of the basic estimate of recovery potential at current conditions.

It is estimated, therefore, that even with allowance for increased crude prices and future technological advances, the idealized potential is of the order of 100 million barrels and that realization of roughly 50 million barrels is a reasonable practical expectation.

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