RESERVOIR STUDY

NORTH VIRDEN SCALLION FIELD, MANITOBA

The California Standard Company
Producing Department
August, 1961.

N.C. no change
L.C. little change [illegible]
N' [illegible]
R.W. reworded

Discrepancies in Exhibits

Well	Discrepancy	Remarks
11-2	Crinoidal isopach shows 11' pay Core analysis shows 8.4' pay	Top 4' not cored. Judgement expects 2' plus to be pay.
16-3	Oolitic isopach shows 12.2' pay Core analysis - 13.6' pay	Looks like error - should be 13.6' pay.
2-10	Crinoidal isopach shows 5' pay Core analysis shows 6' pay	0.6 at 2021 is isolated by 13' dense section - should not be pay.
2-15	Oolitic isopach shows 6.4' pay Core analysis shows 7.1' pay	Looks like error - should be 7.1' pay.
4-15	Cherty isopach shows 23' pay Core analysis shows 19' pay	B.E.S. should have been a little deeper than shown on B.E.S. map (approx. 2072) Well is open hole to 2070 but essentially dry. Indicates lower B.E.S. and more pay.
	Crinoidal isopach shows 12' pay Core analysis - 10.2' pay	Could be error although some of the plugs analysed had K just less than 1 md.
2-20	Crinoidal isopach - 18', Core - 16.1'	2.1' has K 0.83 and ∅ 12.1 - was considered pay.
	Oolitic isopach - 8.0', Core - 6.7' Cherty isopach - 28', Core 26.4'	Core analysis used for isopach was incorrect (was rough copy). Pay should be 6.7' and 26.4' respectively.

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SUMMARY

I Introduction

N.C. The Oil and Natural Gas Conservation Board requested that The California Standard Company up-date the reservoir report written in May, 1958. This current report analyses the primary performance and investigates the potential of secondary recovery of oil by water flooding the Mississippian limestone in the proposed North Virden Scallion Unit #1.

II Findings

A. N.C. The discovery of oil saturation and commercial production in the Lodgepole Formation of the Mississippian at Calstan Scallion Prov. 3-11-11-26 during December, 1953, led to the development of the North Virden Scallion Field.

B. N.C. The original oil was an under-saturated crude at approximately 900 psig. containing 70 cubic feet of gas per barrel of residual liquid, with a bubble point pressure of 145 psig.

C. The estimated original oil-in-place from volumetric calculations is 194,000,000 barrels within the proposed Unit Area, 168,000,000 entire field.

D. Primary performance of the proposed Unit Area indicates a recovery of 25,000,000 barrels. This is 12.9% 12% of the estimated oil-in-place. 20,000,000 Cumulative production to April 30, 1961, for the Unit Area was 10,079,754 barrels, or 5.2% 3% of the estimated oil-in-place. 5,974,038 The recovery by fluid expansion down to the saturation pressure would only account for 0.6%.

E. The bottom hole pressure is declining rapidly as evidenced by the 11 15 psi per month decline at Sun E. Hutchinson Scallion 4-23-11-26. The Unit Area average pressure is now in the order of 200 psi.

F. Water flood calculations indicate a total ultimate primary plus secondary recovery of 55,000,000 barrels from the Unit Area, or 28.4% of the oil-in-place. 35,900,000 22%

SW

III Conclusions

1. Ultimate recovery can be substantially increased by instituting a water flood scheme in the proposed North Virden Scallion Unit #1 area.

RESERVOIR STUDY
NORTH VIRDEN SCALLION FIELD, MANITOBA

This report is a reservoir study of the North Virden Scallion Field but the major emphasis has been placed on the proposed Unit Area (see Figure 1). The general consensus of opinion among most of the Operators in the North Virden Scallion Field was that there would be little or no incentive for the western flank Operators to join the proposed Unit.

HISTORY

N.C. The discovery well, Calstan Scallion Prov. 3-11-11-26 located three miles north of the Town of Virden was spudded on November 28, 1953. Oil saturation was encountered in the Crinoidal Zone of the Lodgepole Formation and further coring and testing indicated commercial production from the four Oolitic Zones. Casing was set at the top of the First Oolite and the open hole was acidized with 500 gallons. Flowing and swabbing yielded 143 barrels at a final rate of 6 barrels/hour. The hole was reacidised with 500 gallons and swabbing yielded 170 barrels in 26 1/2 hours, cutting 0 - 6% water. A third acid job with 4,500 gallons gave 357 barrels in 41 hours at a final rate of 5 barrels/hour with a water cut of 8 - 16%. Tubing, pump and rods were run and the well was put on production December 31, 1953. Initial production was 75 BOPD cutting 20% water. Production had decreased to 20 BOPD with 7% water by April, 1956, when an unsuccessful Crinoidal rework was attempted. Production had decreased to 11 BOPD, cutting 41% water by April, 1961.

N.C. Subsequent offset and step-out drilling by The California Standard Company and other companies continued rapidly through 1955 when at year end 113 wells were producing. NEW At present there are 274 wells in the capable of producing category, 248 of which recorded production during the month of April, 1961.

N In the proposed Unit Area there are 217 wells which will participate in unit production, 202 of which are currently producing.

N Drilling has essentially been completed in the North Virden Scallion Field with the exception of the odd edge well.

GEOLOGY

Note: N.C. The following discussion and observations are based on a paper "Virden Roselea and North Virden", prepared by C. A. Berg, formerly Development Geologist, Virden District Office of The California Standard Company. The paper was given at the Williston Basin Symposium, October 10 - 12, 1956, and the abstract appears in the publication of the Williston Basin Geological Committee.

N.C. The North Virden Field lies on the north-east flank of the Williston Basin, directly north of the Town of Virden. The field is basically a stratigraphic trap in the Mississippian, the limits being partially controlled by a structural nosing.

N.C. The reservoir rocks are part of the Lodgepole Formation of Lower Mississippian age, and are underlain by Ordovician, Silurian and Devonian sediments. The overlying deposits are Jurassic and Cretaceous sediments, and glasial drift. The reservoir rocks are mainly clastic limestones, sub-divided by thin interbeds of argillaceous limestone. The Lodgepole Formation has been sub-divided into three members: the Scallion Member, the Virden Member and the Whitewater Lake Member in ascending order (see Figure 2). All three are oil bearing in the Virden area, although the Whitewater Lake Member is not oil bearing within the limits of the North Virden Scallion Field.

N.C. The Scallion Member is predominantly a finely crystalline cherty limestone conformable with the underlying Bakken Formation, and is approximately 200 feet thick within the field area. The upper productive portion of the Scallion Member, commonly known as the "Cherty Zone" has been leached over a portion of the field (see Figures 3 and 4) increasing the permeability and porosity and destroying much of the structural and textural features of the rock. The leaching by ground waters during an erosion period has taken place regionally over much of the Lodgepole but the most noticeable effect is in the Cherty Zone of the North Virden Scallion Field.

N.C. The Lower Virden Member consists mainly of oolitic limestones interbedded with argillaceous limestone or calcareous shale. Hence its common name, the Oolitic Zone. These oolite bands are cyclic in nature and total four in the area, the Fourth, Third, Second and First Oolites in ascending order. A Fifth Oolite or Fifth Fragmental has been described but generally blends into the Cherty Zone and within this study has been included as a part of the Cherty Zone. Overlying the "Oolites" are argillaceous limestones and shales.

N.C. Above this lies the Upper Virden Member, a bioclastic limestone mainly Crinoidal debris, sometimes crystalline, the "Crinoids" or "Crinoidal".

N.C. The overlying Whitewater Lake Member is not important within the scope of this report and will not be elaborated on. It is generally dolomitised within the field and the rocks up to the top of the Lodgepole Formation are variably argillaceous, dolomitic and anhydritic.

N.C. As mentioned before, the field is partially controlled by structure. This is in the form of a true structural nosing, reflected somewhat by the Lodgepole erosion surface (see Figure 5). Wells in which the Lodgepole Formation is structurally high generally show the effect of post-Lodgepole movement. This results in a fracture system, in some places being anhydrite infilled. There is little evidence of any degree of movement along the fracture planes. The breccia zones within the Scallion Member are thought to be due to infilling of cracks extending to the erosion surface during the Amaranth transgression and are not fault breccias. The structures are thought to be low angle folds and the maximum dip of structure is only five degrees.

COMPLETION TECHNIQUES

The original technique employed was to set 7" casing at the top of the Oolite section, leaving the Oolites and Cherty Zone open. Total depth was somewhere near the base of effective oil saturation in the Cherty Zone.

oil water contact

transition zone.

N Later the trend was to case the wells through the entire pay section and perforate the desired intervals. About half the wells in the proposed Unit Area have been cased through and perforated. In some wells the entire pay section was not penetrated.

L.C A mud acid wash followed by a regular acid squeeze was usually used to stimulate the wells initially, although in some later wells the initial stimulation was a hydraulic fracture. The wells were then swabbed for a short evaluation and a bottom hole pump and rods were run in 2" tubing and the well placed on production. A few wells flowed for a time after being placed on production.

N Over half of the wells in the North Virden Scallion Field have been reworked at least once and approximately 60% have had some sort of frac treatment. Selective stimulation of the separate porous sections has sometimes proved difficult as the zones are quite close and communication immediately behind the casing is common. Many wells which are supposedly completed in one zone must be recovering oil from all the zones because the cumulative oil production exceeds 100% recovery from that zone.

POROSITY AND PERMEABILITY PROFILES

During the course of the North Virden Scallion Reservoir Study a number of porosity and permeability profiles were drawn from the available core analyses. From these a north-south axial cross-section and a number of east-west sections were drawn. The sections showed that although the reservoir was layered within the different pay zones, bands of similar permeability were not traceable throughout the length of the field. This was especially noticeable in the Cherty Zone, with the possible exception of a rather thick and permeable lens near the top.

N.C

One profile, that of Calstan Scallion 12-16-11-26 which was cored through the entire basal carbonate to the top of the Bakken Formation, revealed a number of interesting items (see Figure 6). The Scallion Member here, as in other wells in the field which penetrated its total extent, is approximately 200 feet thick. The porosity was quite high (up to 35%) in the leached zone near the top of the Cherty Zone. Although the porosity did decrease with depth, the Cherty Zone remained continually porous all the way, ranging from 8 - 15% porosity. The horizontal permeability profile suggested a layered reservoir and aquifer. The maximum permeability of the more permeable layers decreased with depth, and the separate layers became as far apart as 20 feet, compared to one foot and less in the pay zone.

L.C.

The Oolites showed moderately high permeability, up to 300 md. where developed. Each Oolite band was definitely separated from the next by dense bands.

N.C

The Crinoidal was fairly continuous with low porosity (10 - 15%) and very low permeability, around 5 md. For the latter two zones this observation seems to be borne out in other wells.

N.C

(seems to have)

The main portion of the reservoir, the Cherty Zone, has sufficient permeability and vertical connection from lens to lens to be reasonably efficiently swept by any secondary recovery program.

ISOPACHS

and thence oil in place

seems to be the

L.C. The largest single variable factor is the "effective pay" thickness. This variable was examined in as much detail as possible,(especially in the Cherty Zone) The best guide is core analysis and approximately one well out of four has had the core analyzed. Unfortunately only half of these were cored to the base of effective oil saturation. A permeability cut-off of 1 md. was used for all zones. It was decided to treat the reservoir as three separate zones for oil-in-place estimates.

R.W. The Cherty Zone, the main oil accumulation, is productive over most of the field. The base of effective oil saturation had to be determined and contoured before effective pay could be estimated and an isopach drawn (see Figure 3). Core analysis, logs and core descriptions were used to determine this base. The base of effective oil saturation cannot be determined accurately since it varies with depth, as can be seen on some Electrical Logs (see Figure 7).

R.W. The top of the Cherty Zone can be readily picked from cores, logs, etc. With the Cherty Zone outlined, top and bottom, the problem of determining effective pay arose. Where the zone was completely penetrated a 1 md. cut-off was used but as can be seen on Figure 8, the isopach of estimated net effective pay, pay values were obtained in five different ways. They are complete core analysis, core analysis extrapolated to the base of effective oil saturation, Microlaterolog values, Microlaterolog values extrapolated to the base of effective oil saturation and values obtained by other available means such as core descriptions, other logs, etc. Where estimates and extrapolations were necessary the reliability of such estimates varies from less than satisfactory, in some areas where information was scant, to satisfactory where good bases for correlation could be established.

R.W. Using the pay values as above and average porosity from core analysis a map of net porosity thickness was drawn (see Figure 9). This provides the pore volume and is later used in calculating the oil-in-place.

L.C. Much the same technique was used for the Crinoidal and Oolitic Zones. The Oolitic Zone had more complete information as in most cases the total section was analyzed. Thus it was not necessary to depend on extrapolation to such a large degree to permit drawing isopachs of pay and porosity thicknesses (see Figures 10 and 11). The procedure for the Crinoidal Zone was similar, although the complete section was not always analyzed (see Figures 12 and 13).

The pay thicknesses and porosity thicknesses arrived at in Figures 8 to 13 inclusive may be expected to deviate somewhat from estimates by others due to the lack of control in some areas and the amount of estimating and extrapolating necessary over the greater portion of the field.

SPECIAL LABORATORY INVESTIGATIONS

A. Water Flood Tests (C.R.C. Project 24.029)

Water flooding tests were run on twelve core samples from California Standard Scallion wells by The California Research Corporation. The distribution of these samples according to zone and permeabilities was as follows: Cherty Zone, seven samples, 3.7 to 98 md., average 32 md., Oolitic Zone, three samples, 9.3 to 192 md., average 68 md., Crinoidal Zone, two samples, 3.2 to 16.1 md., average 9.6 md. The pertinent results of the tests are shown below:

	Cherty Zone	Oolitic Zone	Crinoidal Zone
1. Average residual oil saturations (infinite WOR)	34%	40%	25%
2. Initial oil saturation	76%	79%	67%
3. Average oil saturation at breakthrough	48%	62%	42%
4. Average oil recoveries at breakthrough	36%	20%	38%

Relative permeability ratio versus saturation curves were given for each sample. These are averaged for the Cherty Zone and shown in Figure 14 (see Appendix II B). Also included in the report was a water permeability at flood end versus air permeability curve (shown in Figure 15).

B. Subsurface Fluid Analysis

Reservoir fluid studies have been carried out by Core Laboratories Inc. on three North Virden Scallion field wells, Calstan Scallion 3-21-11-26, Calstan Scallion Prov. 4-11-11-26 and Calstan Scallion Prov. 10-16-11-26. The first two wells mentioned showed comparable results. These tests were run July, 1956 and June, 1954 respectively. The third well, 10-16, which was tested March, 1956, shows quite different results. The average figures from the two compatible tests were used and the results are as follows:

1. The average saturation pressure of the original reservoir fluid was 145 psig at reservoir temperature. This indicates that the reservoir fluid was in a highly under-saturated condition (see section on bottom hole pressures).

2. The fluid yielded 70 standard cubic feet of vapour per barrel of residual liquid. The average initial formation volume factor was 1.045 bbl./bbl.

3. The average oil viscosity was 3.52 centipoise at saturation pressure, and 5.74 centipoise at atmospheric pressure.

BOTTOM HOLE PRESSURES

N.C. The bottom hole pressure at Calstan Scallion Prov. 9-16-11-26 was 906 psig in April, 1955. This was the first accurate pressure taken in the field. A survey in September, 1955, showed a decline to 859 psig. N. Sun E. Hutchinson Scallion 4-23-11-26 has been used as a pressure observation well and provides the most continuous evidence of pressure decline. The pressure has dropped from 895 psig in February, 1956, to 203 psig in May, 1961, for an average decline of 11 psi per month.

N Bottom hole pressures have been taken on wells in the North Virden Scallion Field on eleven different occasions, varying from one to nine wells per survey. The latest survey was taken in May, 1961. In May all wells that were not producing and had the rods removed were surveyed. In addition Calstan Scallion 2-21-11-26, which could make up lost production, was shut in and three pressure readings were taken. The results of all available surveys are shown in Table 1 and the May, 1961, survey results are shown on Figure 16.

N. An isobaric map has not been drawn because of the lack of sufficient control points. The long shut-in times required to obtain a complete build-up and the resulting lost production is the greatest drawback to running bottom hole pressure surveys in this field. In general the pressure in the North Virden Scallion field has declined to an average of approximately 200 psig. Sonic measurements verify this advanced stage of pressure depletion since most wells, excluding the western flank, are pumped off. The western portion of the field, which is under a partial water drive, has an average pressure in the order of 700 psig.

RESERVES AND PRIMARY PERFORMANCE

Original Oil-In-Place

163,000,000 FIELD (1958)

An estimate of the original oil-in-place for the proposed Unit Area was calculated to be 194,000,000 barrels by the volumetric method. Of this, 131,000,000 152,000,000 barrels was contained in the Cherty Zone, 28,000,000 barrels in the Oolitic Zone and 14,000,000 barrels in the Crinoidal Zone. The following field average values were used:

Pencil figures 1958 for total field.

rounded figures

		Cherty Zone	Oolitic Zone	Crinoidal Zone
1.	Footage weighted average porosity	12.9 13.4	11.2 10.7	10.7 9.8
2.	Effective pay thickness	22.1 25.6	5.5 6.8	9.5
3.	Initial oil saturation	59% 71%	51% 71%	48%
4.	Formation volume factor		1.045 bbl/bbl.	

In calculating this total oil-in-place, the Crinoidal only in the southern portion of the field was considered. See details in Appendix 1A. Figure 17 shows the completion zones for each well.

Primary Performance and Decline Curve Analysis

Decline curves have been plotted for all the wells within the proposed Unit Area and for some of the wells outside the Unit Area. Analysis of these curves, to arrive at an ultimate primary reserve figure, becomes extremely difficult because some of the wells have shown little or no decline to date. In addition a large number of wells have been reworked during the past three years.

Several problems arise when recoveries are estimated for individual wells and averaged to get a field recovery figure. The zones in which each well is completed must be taken into account. In some wells there can be little or no communication between zones because reworks in previously unopened zones are very successful. In other wells there must be communication behind the pipe because recoveries are so high. An example of this is Calstan Scallion 12-15-11-26, which was completed in the Crinoidal Zone. Production to April, 1961, indicates a recovery of approximately 60% of the oil-in-place in the Crinoidal and the well is still producing at full allowable. There is no reason to expect recoveries of this magnitude from the Crinoidal reservoir.

The proposed Unit Area as a whole has definitely started to show a decline. The anomalies of the individual decline curves do not appear to greatly affect the average curve. Projecting the average daily production rate curve, in BOPD/well, indicates a recovery of approximately 13% or an ultimate primary recovery of 25,000,000 barrels of oil.

Projection of the average daily production rate curve, in BOPD from the Unit Area indicates a recovery of 27,000,000 barrels of oil or 14%. The effect of wells being removed from production will however tend to make the projected straight line become concave downwards with the ultimate projection closer to 25,000,000 barrels (see Figures 18 and 19 for proposed Unit Area production curves).

Extrapolation of the water cut curves indicate an ultimate recovery of approximately 25,000,000 barrels for the proposed Unit Area at a water cut of 95%.

The water production for the North Virden Scallion Field is shown on Figure 20. Most of the wells in the proposed Unit Area are producing less than 1,000 barrels of water per month but in the west flank of the field most wells produce in excess of 1,000 barrels of water per month. The average water cut in the Unit Area was 42% in April, 1961, whereas in the west flank it was 83%.

The cumulative production from the Unit Area to April 30, 1961, was 10,079,754 barrels. This represents 5.2% of the estimated oil-in-place. The recovery due to expansion of the oil with a pressure drop down to the saturation pressure is less than one percent. This indicates some additional source of energy (see Appendix 1B).

PREDICTION OF RECOVERY BY WATER FLOODING

In the following method of predicting recovery by water flooding the first assumption made was that the Unit Area would be flooded on an inverted 9-spot pattern.

N.C. Water flood recovery was predicted from a combination of Welge's[1] displacement efficiency concept, Dykstra and Parsons[2] vertical sweep efficiency or permeability variation efficiency, and the concept of areal sweep efficiency in pattern flood as explained by Caudle, Erickson and Slobod[3] and (Dyes, Caudle and Erickson)[4]. A brief discussion of the ideas and limitations behind each method is presented here and detailed calculations are shown in Appendix II.

N.C. Welge Method

The Welge Method is a method for computing the oil displaced from a homogeneous reservoir rock by a fluid which can be considered incompressible and immiscible with the oil. It is based on relationships derived by Leverett[5] and by Buckley and Leverett[6]. The mathematical equations needed, the fractional flow and frontal advance rate formulae, are derived by applying Darcy's law to the flowing phases and by material balance considerations. A treatment of this type will give, for any exploitation time considered, a plot of oil saturation against distance in the reservoir. This procedure provides an analytical method of calculation of saturation, hence oil recovery, requiring no integration of the area under the plot. A knowledge of the relative permeabilities is required only over a limited intermediate range of saturations. As stated before, one of the limitations is that the driving fluid is considered incompressible and immiscible with the oil. This is not a critical assumption. The reservoir is considered to be a linear section in Welge's Method. In our calculations the section is considered to be linear with a length equal to the distance between injection and producing well, a depth equal to the pay thickness, and breadth to give the required volume - the same as the volume of oil-in-place. This gives a reasonable approximation.

Other reasonable assumptions which are inherent in the relationships are: viscous flow, continuous distribution of both phases, effective permeabilities are functions of saturations only, and two fluids flowing.

N.C. Limiting assumptions are steady state flow, and homogeneous rock section.

N.C. From the calculations displacement efficiencies are found for various water saturations. Water-oil ratios are calculated from the mobility ratios (hence oil fractions flowing) at the same water saturations. Displacement efficiencies are found as a function of water-oil ratios. Detailed calculations are shown in Appendix II B.

N.C. **Dykstra and Parsons Method**

This method of calculation of water flood recovery predicts the vertical sweep efficiency considering permeability variations in the reservoir rock. It assumes statistical distribution of permeability throughout the section. That is, the logarithim of the permeabilities will show a linear relationship with the percentage on a probability scale. It is assumed that there is no cross-flow between layers. Also, relative water permeabilities behind the interface are considered equal for all strips and, similarly, relative oil permeabilities ahead of the interface are equal for all strips. This is not strictly true in all cases, but theoretically relative permeabilities are functions of saturation for a particular reservoir rock. From the calculated permeability variation and mobility ratio, coverage or vertical sweep efficiencies are found for various water-oil ratios as shown in Appendix II C.

Areal Sweep Efficiency

N.C.

Due to the configuration of flood patterns there will be portions of the oil zone unswept at any particular time in the life of the flood. This efficiency will increase with time and thus with increasing water-oil ratio. From a method discussed by Caudle, Erickson and Slobod [3] and Dyes, (Caudle and Erickson [4]) and results of X-ray shadowgraph studies on models, areal efficiencies can be calculated. Once again conditions have been idealized where reservoir thickness and permeability are uniform and reservoir boundaries are considered as impermeable barriers. From the mobility ratio, areal sweep efficiencies can be found for various producing ratios, thus for various water-oil ratios. For detailed calculations see Appendix II D.

Water Flood Recovery Efficiency

N.C. The various efficiencies are found as functions of water cut, oil cut or water-oil ratio. The recovery efficiency of the flood is:

R = (Displacement efficiency) x (Coverage) x (Areal sweep efficiency)

N.C. If all three vary similarly with W.O.R., i.e. all increase with increasing W.O.R., then the effective recovery efficiency of the flood is a combination of the three and can be applied to the oil-in-place to give an expected recovery. This is what was done here, and detailed calculations are shown in Appendix II E, the end product being an oil cut versus recovery curve for a 9-spot pattern as hypothesized for the North Virden Scallion Unit Area water flood.

80 acre 5 spot

The results of the flood calculations are shown on Figure 21. At water breakthrough 14% of the oil-in-place at the beginning of flood has been recovered. Assuming water flooding commences January 1, 1962, the total ultimate oil recovery is estimated at 55,000,000 barrels. This is made up of 10,800,000 barrels estimated cumulative production to January 1, 1962, plus 44,200,000 barrels under flooding.

10%

9,830,000

Oct 1, 1959

26,010,000

Start Oct 1, 1959 -

35,900,000

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APPENDIX I

RESERVES AND PRIMARY PERFORMANCE

A. Original Stock Tank Oil-In-Place

The original stock tank oil-in-place was calculated from the equation:

$$N = 7{,}758 \; \phi \, A h \, So_i \, \frac{1}{\beta}$$

where
- N = stock tank oil-in-place, barrels
- ϕ = average footage weighted porosity, fractional
- A = surface area, acres
- h = effective pay thickness, feet
- So_i = initial oil saturation, fractional
- β = formation volume factor, res.bbls./S.T. bbl.

1). Porosity, Area and Thickness

The isopach maps previously mentioned were planimetered to give the average pay thickness and the porosity foot map was planimetered to give average porosity feet for the proposed Unit Area. The average porosity can then be found by dividing the average porosity feet by the average pay thickness. The results are as follows:

Zone	Average Pay Thickness	Average Porosity (MAP)	av. ø Core Analysis
Crinoidal *	9.54 9.47	9.77 10.67	10.48
Oolitic	6.78 5.45	10.74 11.23	11.39
Cherty	25.57 22.10	13.38 12.92	14.33

* As previously mentioned the Crinoidal Zone is thought to be effective only in the southern and (western) portion of the field (see Figures 12 and 13).

The term "ø Ah" can thus be obtained from planimetering the porosity thickness map for each zone. Following are the results along with the average factors found in this operation.

Zone	Average Porosity Fractional	Subsurface Area Acres	Average Thickness Feet	ø Ah Porosity Acre Feet
Crinoidal	0.0977	4,132.4	9.54 9.47	3,852
Oolitic	10.74 0.1075 0.1123	7,292.6	6.78 5.45	5,315
Cherty	13.38 0.1339 0.1292	8,414.1	25.57 22.10	28,808
Total			41.89	37,975

2). Oil Saturation

N.C. The average initial oil saturation (So_i) for each zone was calculated as follows:

a). N.C. Cherty Zone

The basis of connate water determination (and thus oil saturation) was the analysis of the core from Calstan Scallion 9-23-11-26. The coring fluid was crude oil. Disregarding shaly and fractured samples the laboratory water saturations (assumed to be true water saturations) were plotted against the corresponding air permeabilities for each sample. The logarithim of the permeability shows a straight-line relationship to water saturation. Therefore, putting a best fit straight line on the plot on semilog paper gives a permeability versus water saturation plot (see Figure 22).

N.C. The average air permeability of the Cherty Zone was found in the following manner:

N.C. Taking all analyzed samples 1.0 md. (maximum horizontal air permeability) and over in the field and grouping them in permeability ranges, a permeability distribution plot is obtained. The summation of footages in each permeability range are used to affix a percentage of the total footage to each group. Plotting the logarithim of permeability against distribution (plotted as "percent greater than") on probability paper will give a straight line as discussed previously under the Dykstra Parsons method of predicting water flood recovery. This will be true if enough samples are taken and if the reservoir does not have two or more distinct lithologic components. Eliminating fractured samples means the curve shows the relationship for matrix permeability and does not take into account local areas of fracturing.

Inserted in Appendix

N.C. The median air permeability on this plot is defined as the "50% point". Here one-half the rock has permeability greater than this 50% value and half therefore has a value less than this value. This point represents then a reasonable average of effective reservoir permeability. The curve for the North Virden Scallion Cherty Zone is shown in Figure 23.

N.C. The percentage scale (or probability scale) is linear in aspect, as is shown by the fact that two percentages numerically equally separated from the 50% point (for example 20% and 80%) are plotted equidistant on either side of that midpoint on a graph. Thus, taking a permeability corresponding to each equal increment of percentage and arithmetically averaging the saturations corresponding to each of these permeabilities (from a permeability versus saturation curve) would give the same result.

The median air permeability in Figure 23 is 10.5 md. and this corresponds to a water saturation of 0.41 or an initial oil saturation of 0.59 or 59%.

The above method of determining connate water saturation and thus initial oil saturation was developed primarily for sand reservoirs. There has been some thought of late that there is usually a good correlation between porosity and water saturation in carbonate reservoirs.

From the oil base core for Calstan Scallion 9-23-11-26 the log of porosity was plotted against water saturation. The best fit curve was established by the method of least squares. At the unit average porosity of 13.4% the water saturation is 29% which corresponds to an initial oil saturation of 71% (see Figure 24).

California Research Corporation in conjunction with Project 24,029 conducted oil-water capillary pressure tests on five plugs from the Cherty Zone. At a capillary pressure of 20 psi the average water saturation was 21%.

One plug from Calstan Scallion 7-11-11-26, which was analyzed for connate water by the restored state method, indicated a water saturation of 23%.

A mercury injection capillary pressure test run on Sun G. Clarke 2-20-11-26 indicated a water saturation of 17% on the only Cherty Zone sample that had a permeability greater than 1.0 md.

The connate water saturations above range from a low of 17% to a high of 41%. The arithmetic average is 26.5%. It was felt the greater emphasis should be placed on the water saturation arrived at using the data from 9-23-11-26, which was cored using an oil-base mud. Therefore, it was assumed that the average water saturation for the field was 29% and thus the initial oil saturation was 71% in the Cherty Zone.

b). Oolitic Zone

The distribution plot of Oolite samples, constructed as described above, is shown in Figure 25. As can be seen from Figure 26, which is a plot of the Oolite samples from 9-23-11-26, with respect to permeability and water saturation there appears to be little relationship between the two. The arithmetic average water saturation is 49%.

Water saturation was plotted versus porosity and the method of least squares applied to all the points to get a best fit curve (see Figure 27). At the weighted average porosity for the Unit Area of 10.7% the water saturation would be 29%. As can be seen from the curve the Oolitic Zone in 9-23-11-26 is not really representative of the Oolites over the Unit Area as few samples are near the field average.

One sample from the California Research Corporation Project 24,029 was in the Oolitic Zone and at a capillary pressure of 20 psi, oil to water, the water saturation was 30%.

Six samples from Calstan Scallion Prov. 7-11-11-26 were checked by the restored state method and indicated an average water saturation of 25%.

The best correlation of all the above mentioned methods was that between porosity and water saturation. For this reason it was decided to assign the Oolitic Zone 29% water saturation and thus 71% initial oil saturation.

c). <u>Crinoidal</u>

The Crinoidal Zone was not well developed in Calstan Scallion 9-23-11-26 and therefore not cored and analysed for water saturations. The Crinoidal has been cored in oil in the South Virden Field, however, and it is thought to be lithologically similar. Samples taken from oil base cores at Calstan South Virden Prov. 15-11-10-26 and Calstan South Virden CPR 12-1-10-26 in the Crinoidal member show an interesting relationship. Most of the points fall near the best-fit line constructed for North Virden Scallion Cherty Zone on a log permeability versus water saturation plot. Although much less permeable on the average the Crinoidal must be lithologically similar to the Cherty Zone, at least in regard to water saturation varying with permeability (see Figure 22). The median air permeability of the Crinoidal is 3.0 md. as shown on the distribution plot, Figure 28. Using this median value and the Cherty Zone saturation plot the water saturation is 0.52, and oil saturation of 0.48 or 48%.

8-9 [illegible]

F22

The plot of porosity versus water saturation showed that with increasing porosity the water saturation also increased. It was therefore assumed that there was no relationship between porosity and water saturation. For this reason and because there was no other reliable data available it was assumed that the water saturation in the Crinoidal Zone was 52% and therefore the initial oil saturation was 48%.

3). <u>Formation Volume Factor</u>

β , the formation volume factor was calculated by averaging the results of subsurface fluid analyses of samples from Calstan Scallion Prov. 4-11-11-26, and Calstan Scallion 3-21-11-26. The results are as follows:

Scallion Well No.	β bbl./bbl.
4-11	1.047
3-21	1.044
Average	1.045 bbl./bbl.

R11 -210 bbls./S.T. bbl.

The original oil-in-place calculations for each of the three zones are as follows:

Cherty Zone

Bo/acre/ft φ acre/ft Soi
29,833 0.59
N = (7,758) (28,808) (0.71) (1/1.045) β volume formation factor
0.76 c.c.

151,846,554
= 152,000,000 barrels/unit area
131,000,000 " /entire field

or, using average figures

0.1292 0.59
N = (7,758) (0.1339) (40) (0.71) (1/1.045)

.1338 used = 28,200 bbl./ft./40 acre lease
23,600 " " " "

or N = (7,758) (0.1338) (0.71) (1/1.045)

= 705 bbl./acre-foot
566 " / "

Oolitic Zone

4,710 0.51
N = (7,758) (5,315) (0.71) (1/1.045)
0.79 c.c.

28,015,288
= 28,000,000 bbls./unit area
18,000,000 " /entire field

0.1123 0.51
or N = (7,758) (0.1075) (40) (0.71) (1/1.045)

= 22,700 bbl./ft./40 acre lease
17,000 " / " / " "

or N = (7,758) (0.1074) (0.71) (1/1.045)

565
= 568 bbls./acre-foot
425 " / " "

Crinoidal Zone

3,525 0.48
N = (7,758) (3,852) (0.48) (1/1.045)

13,726,537
= 14,000,000 bbls./unit area
(12,561,278) → 14,000,000 " /

or N = (7,758) (0.0977) (40) (0.48) (1/1.045)

= 13,900 bbls./ft./40 acre lease
15,200

or N = (7,758) (0.0977) (0.48) (1/1.045)
0.67 c.c.

= 348 bbls./acre-foot
380

A summary of the oil-in-place and their relative amounts are as follows:

		Oil-In-Place	Percent of Total	
Cherty Zone	131,000,000	152,000,000	79%	80% 81%
Oolitic Zone	18,000,000	28,000,000	14%	11% 11%
Crinoidal Zone	14,000,000 12,561,278	14,000,000	7%	9% 8%
Total	161,800,000	194,000,000	100%	

B. Primary Performance

The primary reserves of the proposed North Virden Scallion Unit Area have been estimated, as previously explained, at 25,000,000 barrels. This represents a recovery factor of: 20,000,000 FIELD

$$RF = \frac{25,000,000}{194,000,000} = 12.9\% \quad \begin{matrix} 12.3 \\ 12.4 \end{matrix}$$

or, on an average well basis (producing from all zones)

$$\Delta N = \overset{\text{Recovery}}{0.129} \left[\overset{\text{Cherty}}{(28,200)} \overset{\text{feet of pay}}{(25.57)} + \overset{\text{Oolitic}}{(22,700)} (6.78) + \overset{\text{Crinoidal}}{(13,900)} (9.54) \right]$$

$$= (0.129)\ (1,008,000)$$

$$= \underset{911,000}{130,000} \text{ barrels}$$

These figures are from the above oil-in-place calculations and refer to a well draining all zones, and with average thicknesses.

N.C. The recovery due to oil expansion during a pressure drop from 900 psi (original bottom hole pressure) to 145 psi (saturation pressure) is:

$$\frac{\Delta N}{N} = \frac{\beta s - \beta i}{\beta i}$$

where βs = formation volume factor at saturation pressure

βi = original formation volume factor

therefore $\dfrac{\Delta N}{N} = \dfrac{1.051 - 1.045}{1.045} = 0.6\%$

APPENDIX II

INJECTIVITY AND FLOOD PREDICTION

A. Injectivity Calculations

The water injectivity rates were calculated from the formula:

$$Q = \frac{0.003541\ K_w h\ \Delta P}{\mu \beta \left(\ln \frac{d}{r_w} - 0.6190\right)}$$

β - for water is unity.

not used? or unity

where
Q = injection rate, bbl./day
K_w = reservoir permeability to water, millidarcies
h = vertical section, feet
ΔP = pressure differential (P surface + P well bore - P reservoir)
μ = viscosity of injection water at reservoir conditions, centipoise
d = distance from injection well to producing well in flood pattern, feet
r_w = effective well bore radius, feet

This is derived from Darcy's flow formula and is applied to an average North Virden Scallion well assuming the following:

P_{wb} = 0.433 psi/ft. x 2,100 ft. = 900 psi *fresh water*
P_{inj} = 1,100 psi (not to exceed over burden pressure)
P_{res} = 500 psi (average over flood life)
$\therefore \Delta P$ = 1,100 + 900 - 500 = 1,500 psi
μ = 0.864 cp at reservoir temperature *fresh water @ 80°*
d = 1,320 feet, between injection and nearest producer
r_w = 25 feet (radius of fracturing assumed)

Therefore,

$$Q = \frac{(0.003541)\ (1{,}500)\ (K_w h)}{0.864\ \left(\ln \frac{1320}{25} - 0.6190\right)}$$

$$= 1.84\ \text{BWPD/md.ft.}$$

Applying this to average permeabilities and pay sections:

Cherty Zone

$$Q = 1.84\ K_w h$$

$$= (1.84)\ (2.55)\ (\overset{h}{25.6})$$

25.57

$$= 120\ \text{BWPD}$$

K_w = 2.55 ? [illegible]
[illegible]
Page [illegible] 2(a) para [illegible]
K = 9.23.

Oolitic Zone

Kw 27?

$$Q = (1.84)\ (27)\ (6.8)$$

6.78

337.8

$$= 340 \text{ BWPD}$$

Crinoidal Zone

Kw 0.34 - land

$$Q = (1.84)\ (0.34)\ (9.5)$$

9.54

5.9

$$= 6 \text{ BWPD}$$

Sample calculations for total injectivity in all zones for specific wells are as follows:

Calstan Scallion 2-15-11-26

$$Q = 1.84\ (7.3)\ (26.4)$$

$$= 355 \text{ BWPD}$$

Calstan Scallion 12-22-11-26

$$Q = 1.84\ (7.3)\ (63.2)$$

$$= 850 \text{ BWPD}$$

The above injectivity calculations provide order of magnitude estimates of the North Virden Scallion Unit Area injectivity and demonstrate satisfactory injectivity for flooding. The estimates are considered to be conservative for two reasons:

1. A 5-spot pattern steady state formula was used and the planned injection well density for the Unit Area is much less.

2. The formula, as above, was applied to all wells regardless of the stimulation method and is considered to be inappropriate for fractured wells.

B. **Prediction of Water Flood Recovery by the Welge Method**

As explained in the report the Welge Method is an analytical method of calculating saturation as a function of permeability ratios, giving fractions of each component flowing. From average saturations over a period, residual saturations are calculated and then displacement efficiencies which are expressed as a function of water/oil ratios. The steps are shown below. The basic relationship used is the fractional flow formula:

$$f_o = \frac{h}{c + h} \qquad (1)$$

where: f_o = fraction of oil flowing in reservoir

h = k_o/k_w = relative permeability ratio, oil to water

c = $\mu o/\mu w$ = ratio of viscosity of reservoir oil to viscosity of reservoir water

This neglects capillary pressure gradient, the term usually being negligible and gravitational forces which are negligible in a flat lying reservoir such as North Virden.

1. From laboratory tests by California Research Corporation (Project 24,029) k_w/k_o vs S_w curves are found for the various core plugs tested. These curves are averaged as shown in Table II and one average k_w/k_o curve is drawn for the Cherty Zone (Figure 14). Because some of the k_w/k_o curves do not extend to the lower value range the average k_w/k_o curve was adjusted to compensate for this deficiency. From this curve values of k_w/k_o for any value of S_w may be found.

   Chosen values of S_w are placed in column (1) (see Table III) and their corresponding values of k_w/k_o from Figure 12 14 in column (2).

2. From equation (1), on substituting:

$$f_o = \frac{1}{1 + \frac{\mu o}{\mu w} \frac{k_w}{k_o}} \qquad (2)$$

   The value of $\frac{\mu o}{\mu w}$ is calculated to be:

$$\frac{\mu o}{\mu w} = \frac{3.98}{0.864} = 4.61$$

   Where μo is the average oil viscosity from the P.V.T. analyses discussed in the report and corrected to a reservoir temperature of 80° F. The viscosity of fresh water at this temperature is 0.864 c.p.

   The values of $\frac{\mu o}{\mu w} \frac{k_w}{k_o}$ can then be calculated from this value and column (2) and are listed in column (3).

3. The fraction of oil flowing f_o is calculated from equation (2) using the values from column (3) for each saturation. The results are listed in column (4) of Table III.

4. A graph of f_o versus S_w is plotted in Figure 29. The lower extent of the curve is taken to be where $S_w = 0.29$, the initial water saturation of the Cherty Zone.

5. From the relationship:

$$\frac{1}{Q_i} = \frac{df_w}{dS_w}$$

   where Q_i = the number of pore volumes injected $\frac{1}{Q_i}$ can be calculated from the f_o versus S_w curve.

Formula for [illegible]

Since $f_w = 1 - f_o$ the f_w scale can be substituted for f_o in reverse order, (see Figure 29).

Then for each value of S_w, $\frac{1}{Q_i}$ = the slope of the f_w vs. S_w curve at that value of S_w. The values of $\frac{1}{Q_i}$ are calculated and shown in column (5) of the Table.

6. Since $Q_i\ f_o$ is the number of pore volumes of oil flowing at a given time, and this is equal to the change in saturation $S_{av} - S_w$ this term can be calculated for any given saturation S_w and shown in column (6).

7. Column (7), S_{av} is column (6) $Q_i\ f_o$ (or $S_{av} - S_w$) plus column (1) S_w.

8. The residual oil saturation S_{or} in column (8) is $1 - S_{av}$ for each particular S_w.

9. The efficiency of displacement of oil is the ratio:

$$\frac{S_{oi} - S_{av}}{S_{oi}}$$

this can be calculated for each value of S_w and is shown in column (9).

10. The reservoir water/oil ratio is shown in column (10) and is calculated from column (4) using the relationship:

$$\text{Res. WOR} = \frac{1 - f_o}{f_o}$$

Ed Where f_o is the fraction of oil flowing at any particular saturation S_w which now has a displacement efficiency E_d corresponding to it. A curve of E_d versus WOR is then drawn and shown in Figure 30.

C. The Dykstra-Parsons Prediction of Recovery

The prediction of flood recovery by the Dykstra-Parsons Method as previously mentioned expresses the efficiency of flooding as coverage C or E_v, vertical sweep efficiency from the statistical permeability variation V.

C or E_v

From graphs prepared by Dykstra and Parsons [2] and shown in Figures 31, 32, 33 and 34, the coverage C (or E_v) can be found for the various water/oil ratios knowing the permeability variation V and the mobility ratio γ.

From Figure 23 the permeability variation in the Cherty Zone is shown to be:

$$V = \frac{10.5 - 2.55}{10.5} = 0.76$$

The mobility ratio γ is defined as:

$$\gamma = \frac{k_{rw}}{k_{ro}} \frac{\mu o}{\mu w}$$

where k_{rw} = relative permeability to water at end of flood
k_{ro} = relative permeability to oil at initial water ?
μw = viscosity of injected water, at reservoir conditions
μo = viscosity of oil, at reservoir conditions

From data in California Research Corporation's Report (Project 24,029) on water flood tests, a graph of oil permeability to air permeability was constructed (see Figure 35). At the median air permeability of 10.5 md. the permeability to oil is 4.5 md.

From a similar graph constructed in this same California Research Corporation Report, the water permeability is 0.75 md. at 10.5 md. air permeability (see Figure 15).

The oil and water viscosities which have been discussed previously are as follows:

μo = 3.98 c.p. at 80° F. and 600 psi
μw = 0.864 c.p. at 80° F. and 600 psi

Therefore, the mobility ratio, γ, is calculated as follows:

$$\gamma = \frac{(0.75)\ (3.98)}{(4.5)\ (0.864)} = 0.77$$

From the graphs the following results are obtained:

WOR bbl./bbl.	Coverage, C (or E_v)
1	0.34
5	0.63
25	0.835
100	0.92

These results are shown graphically in Figure 36.

D. Areal Sweep Efficiency of Water Flooding

The idea that areal efficiency will increase with time in a flood, the pattern becoming more completely filled out, is widely accepted. This is discussed by Caudle, Erickson and Slobod [3] and Dyes, Caudle and Erickson [4] and from X-ray shadowgraph studies on models experimental values of this efficiency have been obtained for various positions of a well in a flood pattern.

The efficiency is expressed in graph form for various mobility ratios M and for various water cuts. It will be noted that the mobility ratio M is defined as:

$$M = \frac{k_o}{k_w} \frac{\mu w}{\mu o}$$

which is the reciprocal of the ratio γ , previously expressed in the Dykstra-Parsons Method. Therefore,

$$M = \frac{1}{\gamma} = \frac{1}{0.77} = 1.30$$

The results show the following for a direct offset well in a 9-spot pattern, with M = 1.30:

ψ_s (water cut)	WOR (bbl./bbl.)	E_a (areal sweep eff.)
0	0	0.58
0.5	1.0	0.73
0.6	1.5	0.79
0.7	2.33	0.85
0.8	4.0	0.93
0.85	5.67	0.95
0.9	9.0	0.97

E_a These figures are shown in graph form in Figure 37 as WOR vs E_a (areal sweep efficiency).

E. Water Flood Recovery Efficiency

It may be noted that the first two efficiencies E_d and E_v are calculated for the Cherty Zone only. There is not enough information available to evaluate the other two zones by the Welge Method. The permeability variation in the Crinoidal is close to that in the Cherty Zone, and although the variation V in the Oolites is larger the one set of figures is used rather than averaging the two sets of results. The oil-in-place in the other zones (approximately 20% of total) is comparatively small in respect to the Cherty Zone and therefore any error in one or more of the efficiencies would not greatly influence the overall result of predictions. Therefore one set of flooding efficiencies are applied to the total oil-in-place and it is thought that any error incurred in doing so would be within the accuracy of the prediction methods.

The three flooding efficiencies E_d, E_v and E_a are expressed as functions of WOR and are combined in Table IV. The point of water breakthrough is usually taken as where the f_w versus S_w curve departs from being a straight line (see Figure 29). However, in this case the curve has a changing slope at all saturations above the original S_w (0.29) which naturally is the lower limit. Therefore the calculated reservoir WOR at this point gives the point of breakthrough in Table IV. The producing WOR is given by β x $WOR_{Res.}$ in this Table. The recovery R is E_d x E_v x E_a, the product of the three fractional recoveries. The stock tank oil cut is found from the producing WOR and thus becomes:

$$\text{S.T. Oil Cut} = \frac{1}{1 + \beta \, WOR_{Res.}}$$

A graph of percent recovery R versus stock tank oil cut is shown in Figure 21. A recovery of 14% is indicated to breakthrough, at which point the oil cut drops to 34%.

Assuming water flooding starting January 1, 1962, the remaining oil-in-place is estimated at 181,200,000 barrels. The recovery to breakthrough is therefore predicted at 25,400,000 barrels or 14% of this oil-in-place. The total ultimate recovery is estimated at 55,000,000 barrels or 28.4% of the oil-in-place. This assumes that the field can be produced to a 5.4:1 water/oil ratio and that the maximum fluid production would not exceed 10,000 barrels per day. The economic limit of the Unit was assumed to be 7 BOPD/well. The predicted total recovery would be made up of 10,800,000 barrels primary oil production to January 1, 1962 and 44,200,000 barrels of secondary oil production.

Dec. 31/78

Cum Prod (NVS #1) = 45,200.000

WOR = $\frac{356,232}{136,636}$ (Dec/78) = 2.6

Fluid Prod = 15900 Bbl/day

Avg. Prod per well = 26 BOPD

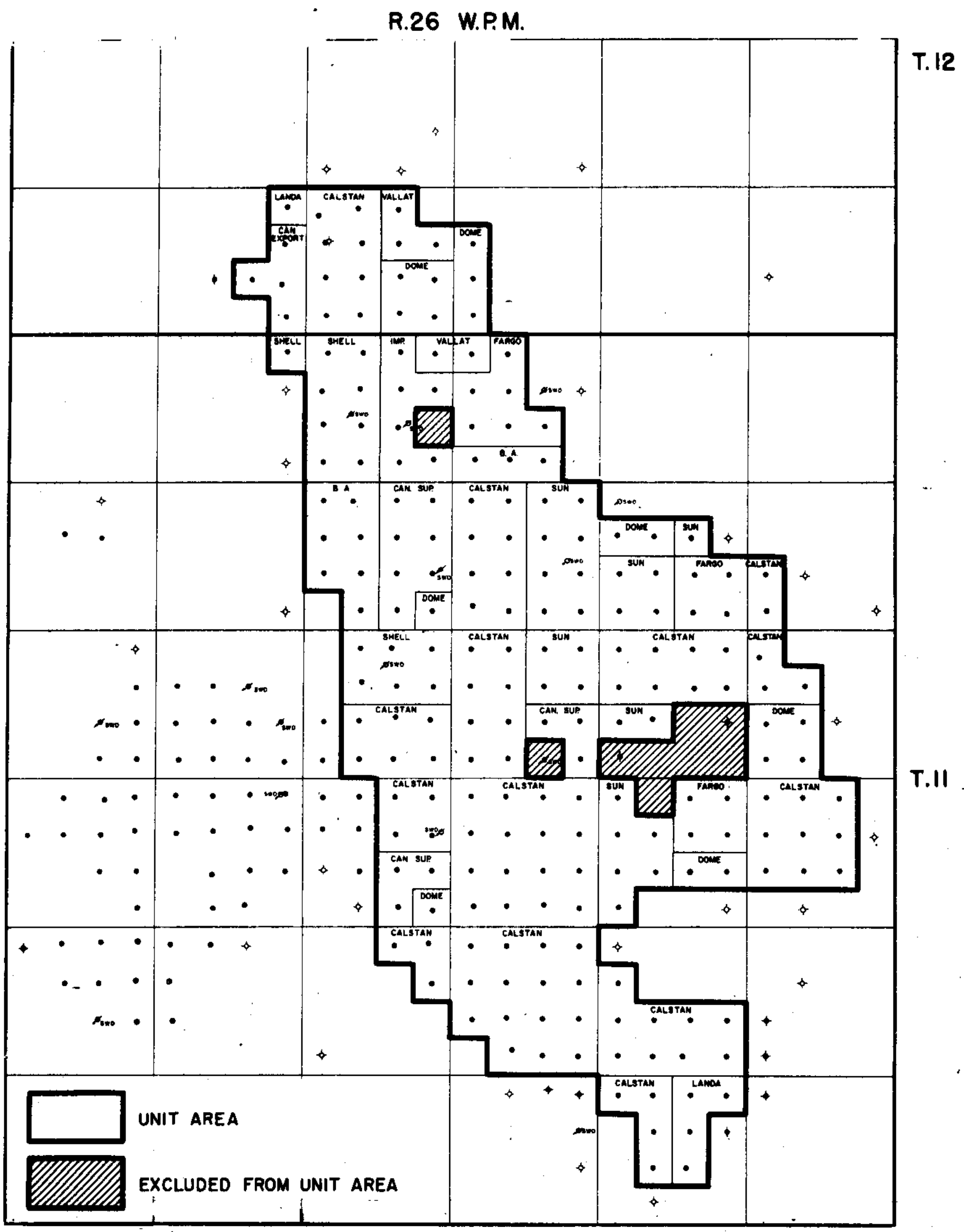


FIGURE I

NORTH VIRDEN SCALLION FIELD

MAP OF PROPOSED UNIT AREA

MAY, 1961

SCALE IN MILES

0 1 2

[redacted]

FIGURE 2

NORTH VIRDEN SCALLION

STRATIGRAPHIC SECTION OF PRODUCING ZONES

AGE	FORMATION	MEMBER: STANTON, 1955		MEMBER: FIELD NOMENCLATURE
JURASSIC	WATROUS RED BEDS	WATROUS RED BEDS		
MISSISSIPPIAN JURASSIC UNCONFORMITY				
MISSISSIPPIAN	LODGEPOLE	? WHITEWATER LAKE MEMBER		?
		VIRDEN MEMBER	UPPER	CRINOIDAL
			LOWER	? OOLITES
		SCALLION MEMBER		CHERTY ZONE
	? BAKKEN	? BAKKEN		
DEVONIAN	? THREE FORKS	? THREE FORKS		

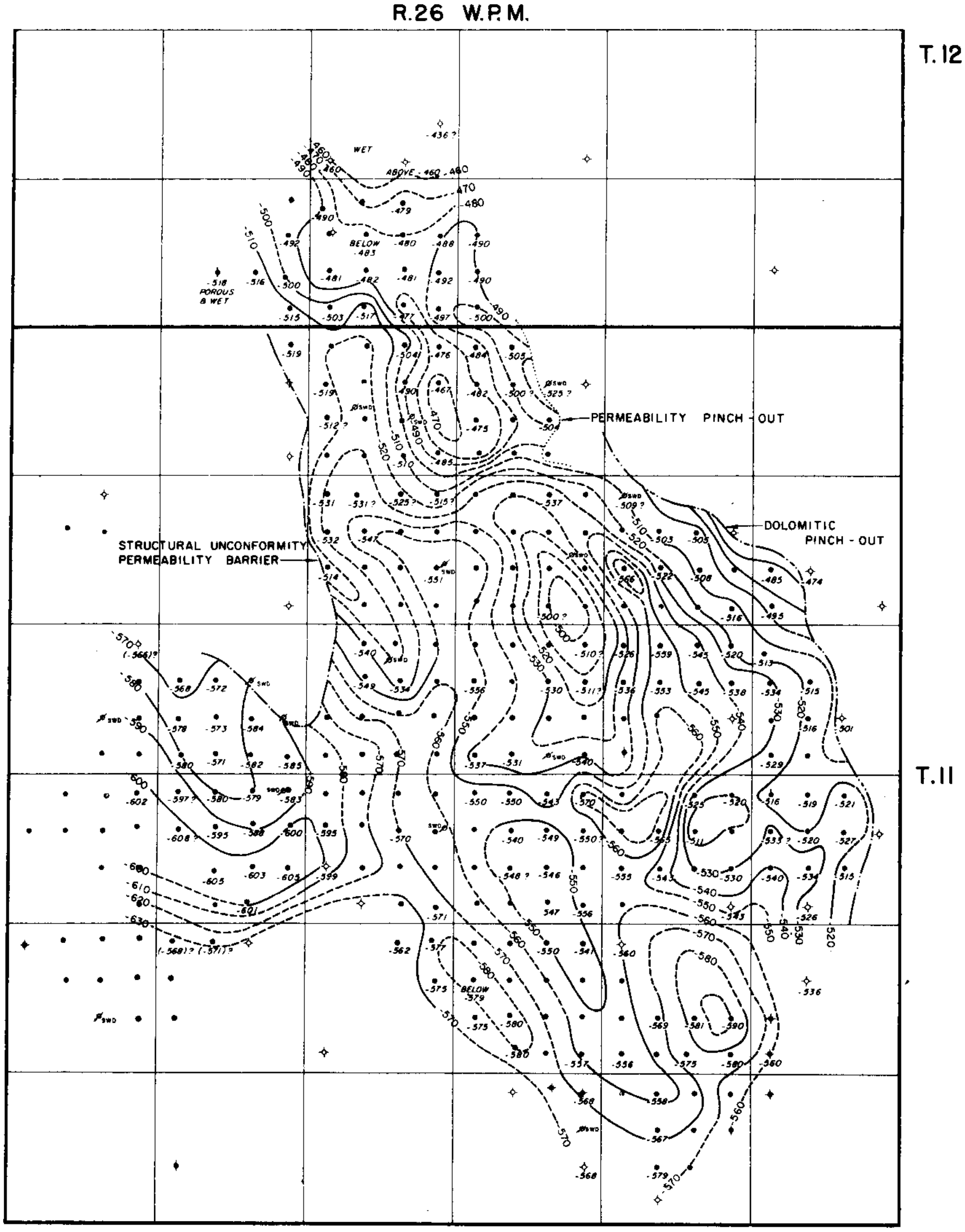


FIGURE 3

NORTH VIRDEN SCALLION FIELD

CONTOURS ON BASE OF EFFECTIVE OIL SATURATION

C.I. 10 Ft.

SCALE IN MILES

0 2

MAY, 1961

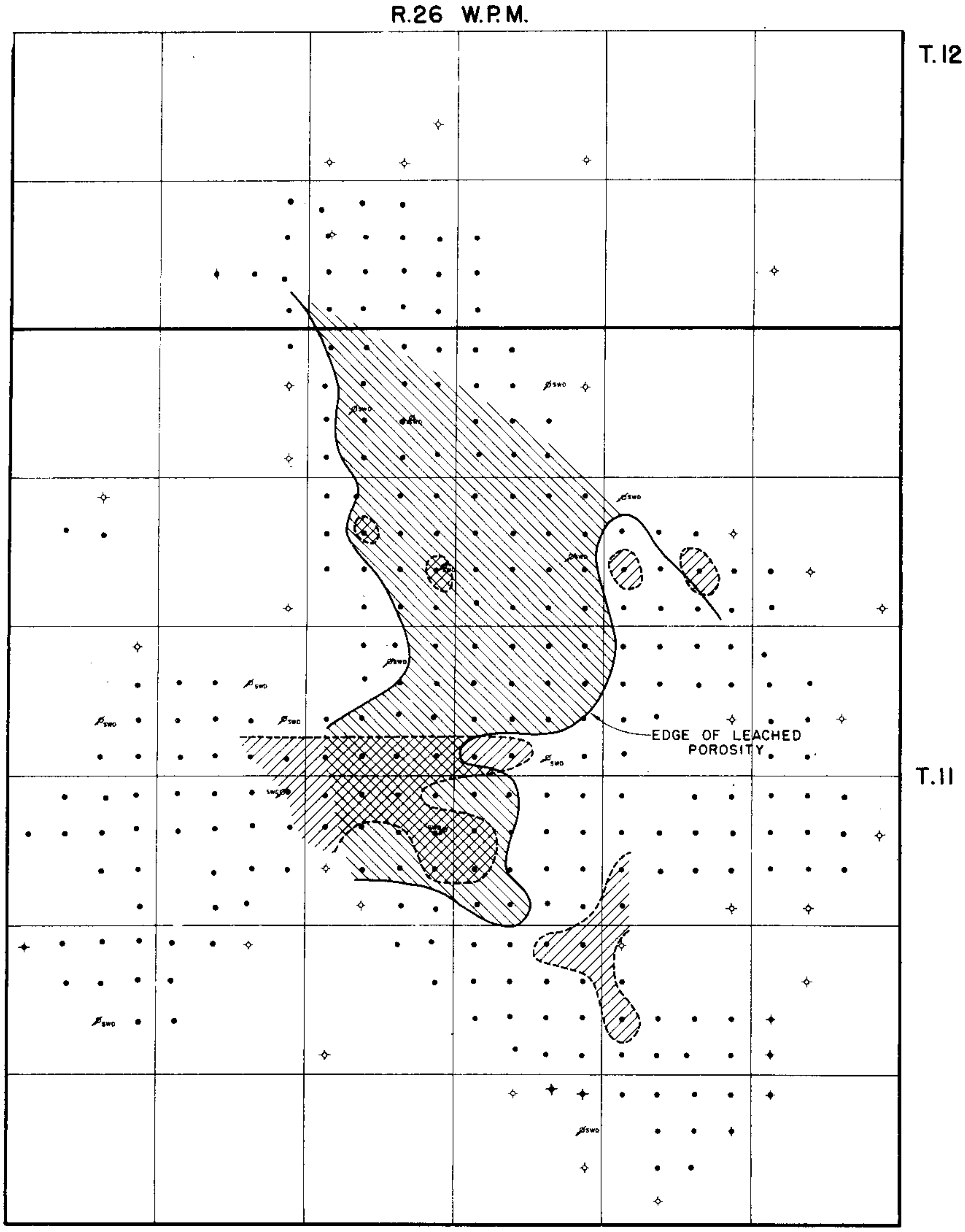


FIGURE 4

NORTH VIRDEN SCALLION FIELD

CHERTY ZONE

SHOWING AREAS OF OPEN FRACTURING AND LEACHED POROSITY

-LEGEND-

OPEN FRACTURES

LEACHING

SCALE IN MILES

0 2

MAY, 1961

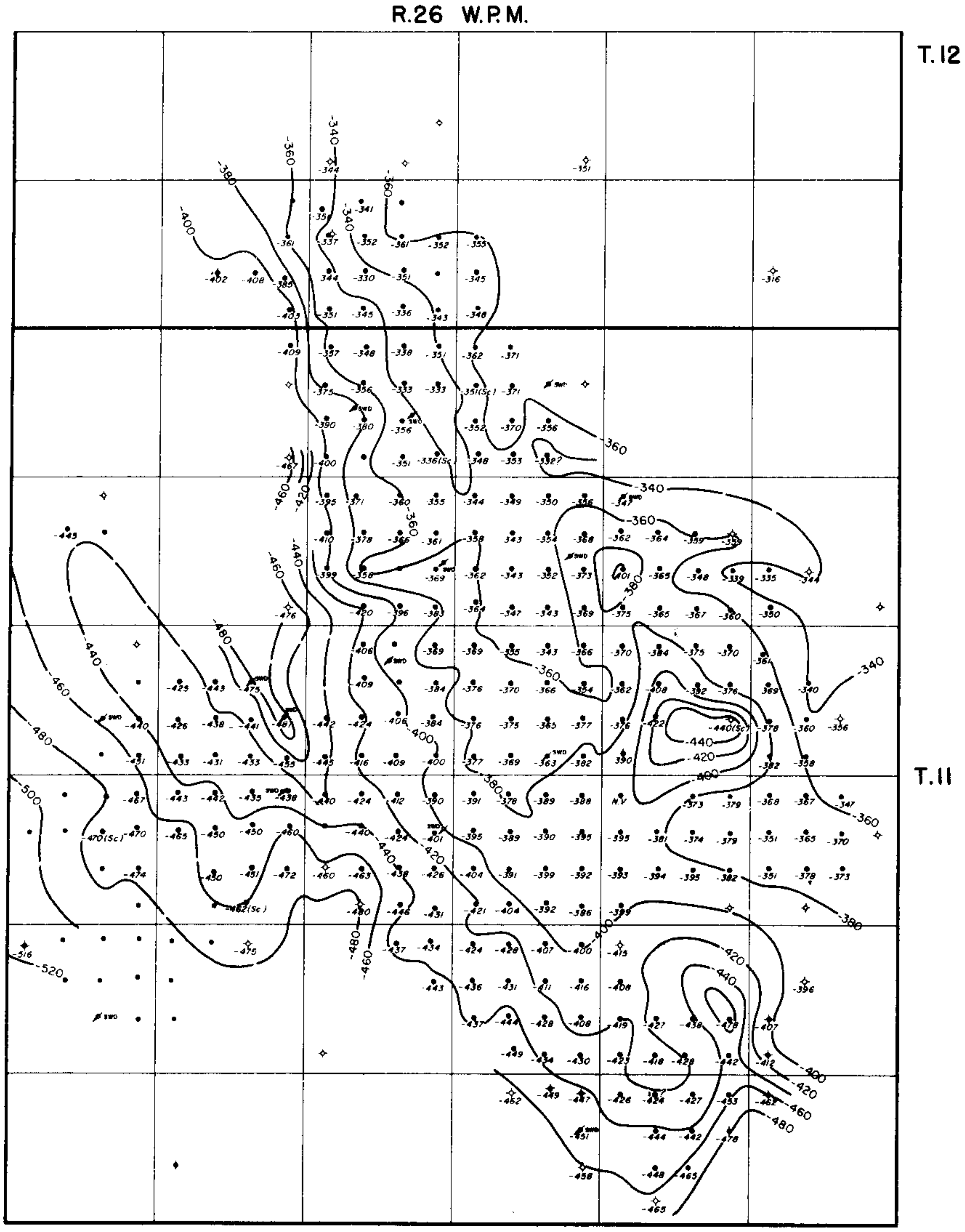


FIGURE 5

NORTH VIRDEN SCALLION FIELD

STRUCTURE CONTOURS
ON TOP OF
MISSISSIPPIAN

MAY, 1961

SCALE IN MILES
0 1 2

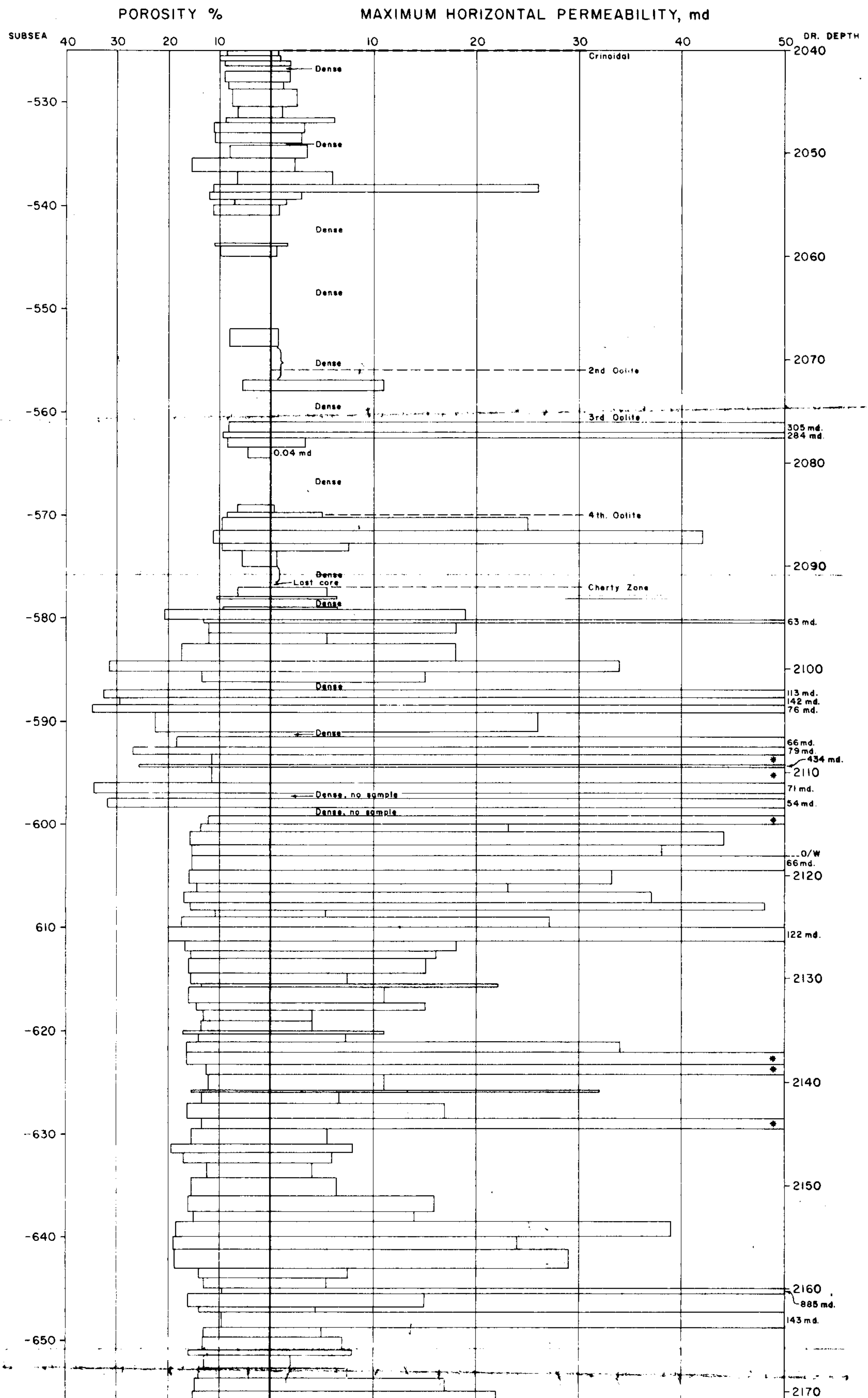
C.I. 20 Ft.

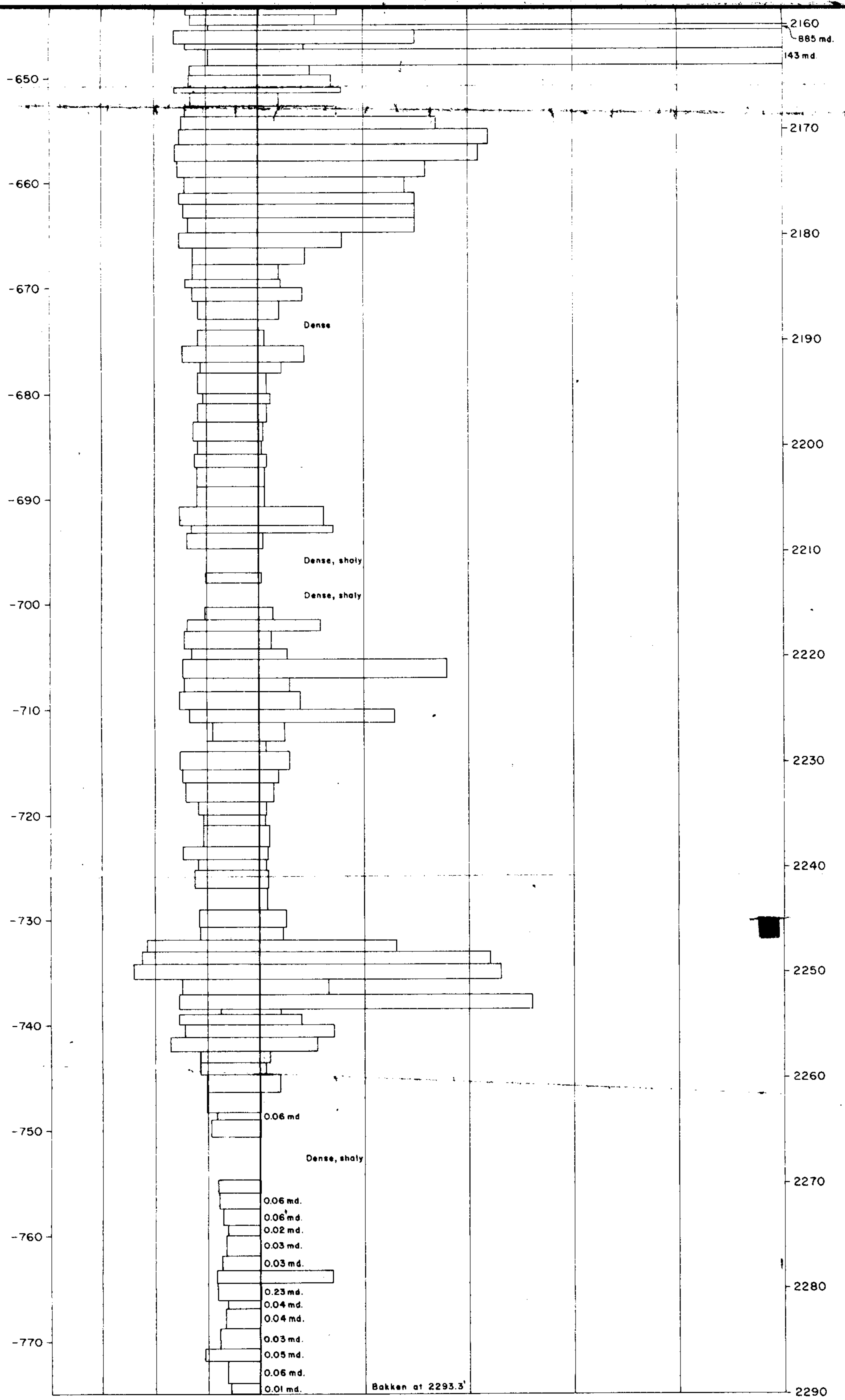
FIGURE 6

POROSITY AND PERMEABILITY PROFILE

CALSTAN SCALLION 12-16-11-26

K.B., 1515'





Note: * Indicates fractured samples, permeability greater than 30,000 md.

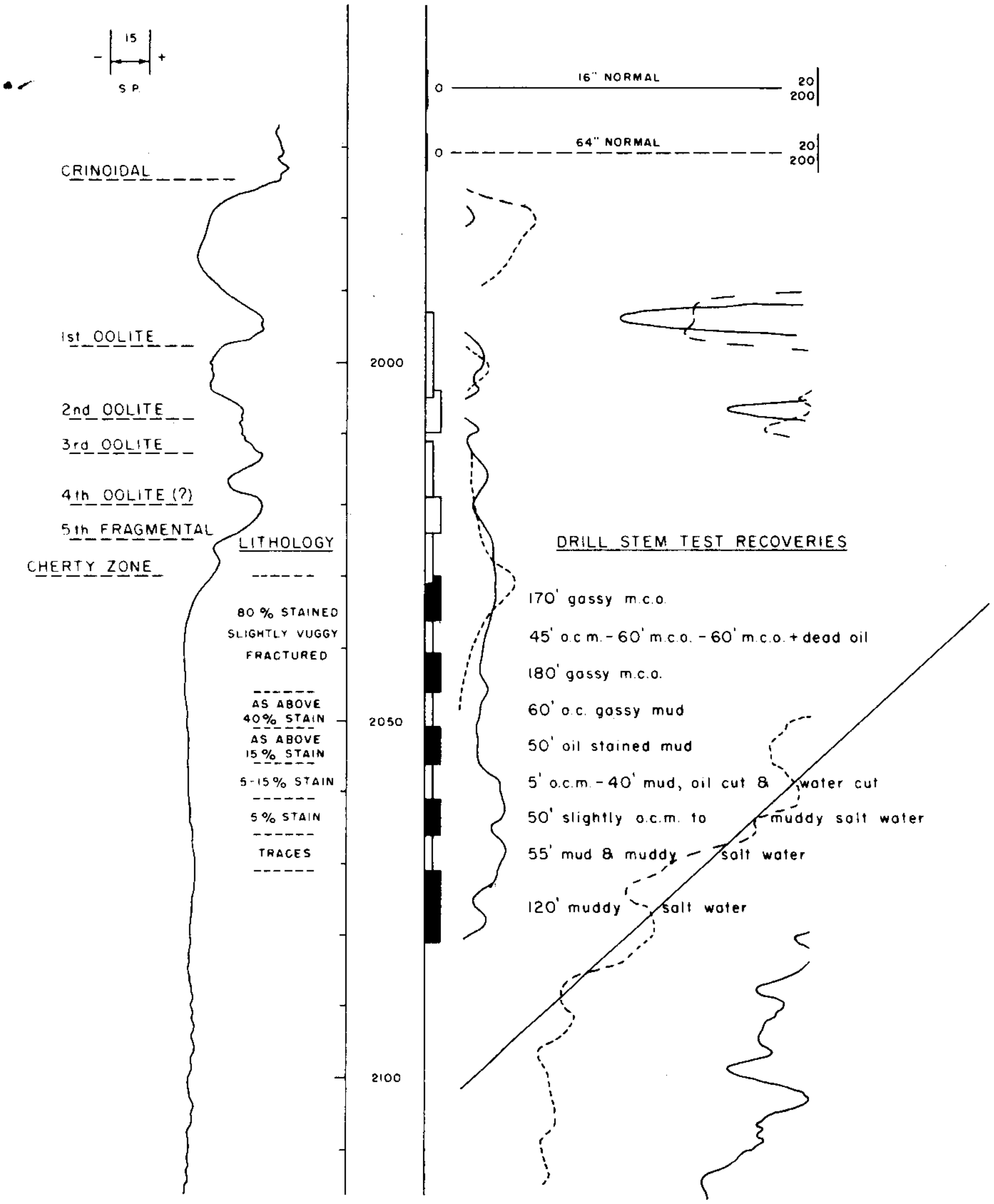
FIGURE 7

ELECTRIC LOG

CALSTAN SCALLION 5-11-11-26

SHOWING

OIL SATURATION VARIATION WITH DEPTH



CHERTY ZONE DISCREPANCIES

Well 4-15   Isopach shows 23' pay
             Core Analysis 19' pay

2-20   Isopach shows 28' pay
        Core Analysis 26.4' pay

16-3 Isopach 6'
Core Anal 7.3'

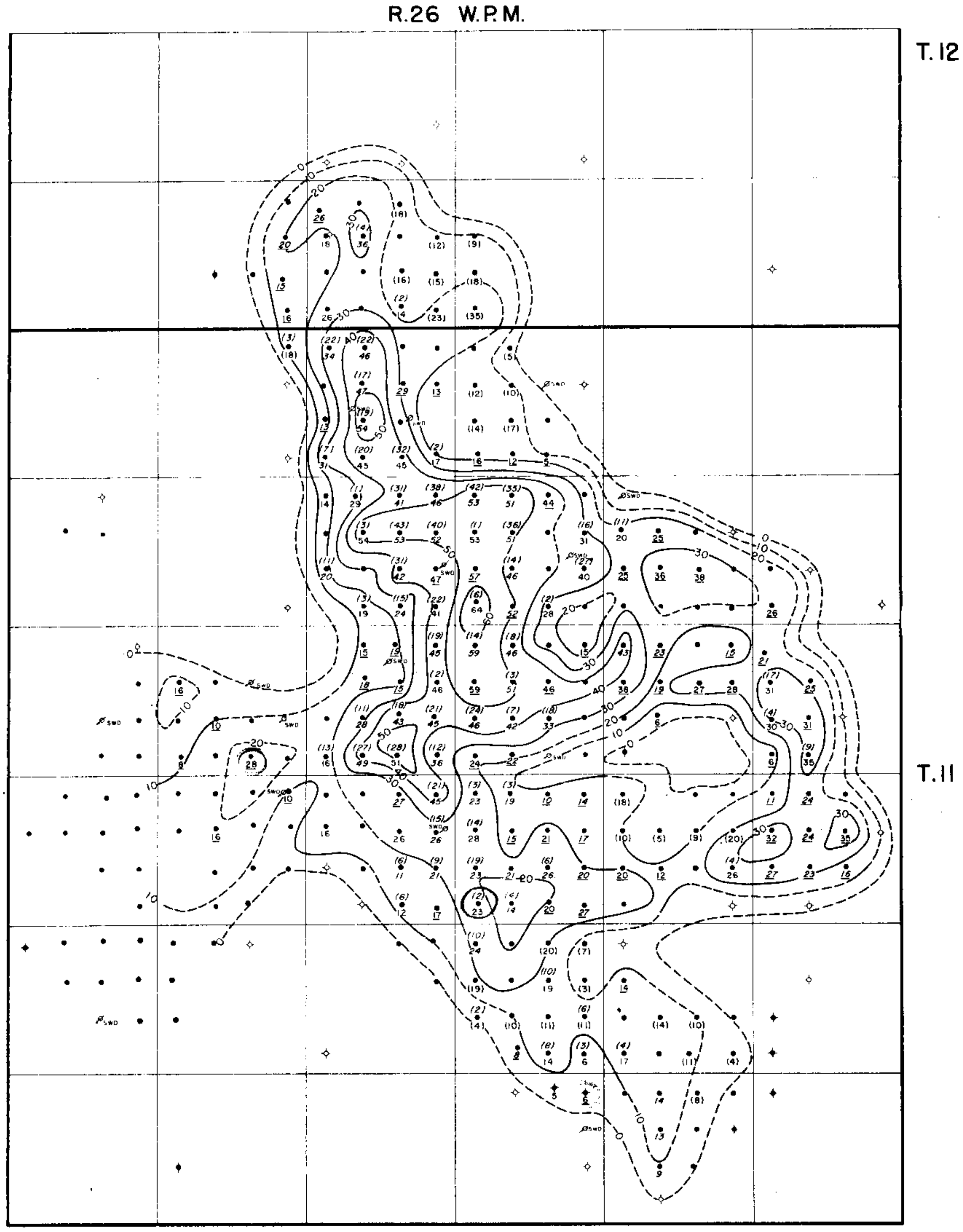


FIGURE 8

NORTH VIRDEN SCALLION FIELD

CHERTY ZONE

ISOPACH OF

ESTIMATED NET EFFECTIVE PAY

C. I. 10 FT.

SCALE IN MILES

0 2

LEGEND

- 20 — CORE ANALYSIS VALUE EXTRAPOLATED TO BASE OF EFFECTIVE OIL SATURATION.
- *26* — MLL VALUES EXTRAPOLATED TO BASE OF EFFECTIVE OIL SATURATION
- 32 (underlined) — MEASURED CORE ANALYSIS VALUE NO EXTRAPOLATION REQUIRED
- *23* (underlined) — MLL VALUE - NO EXTRAPOLATION REQUIRED
- *(4)* — EXTRAPOLATED PAY
- (8) — VALUE OBTAINED BY OTHER MEANS

MAY, 1961

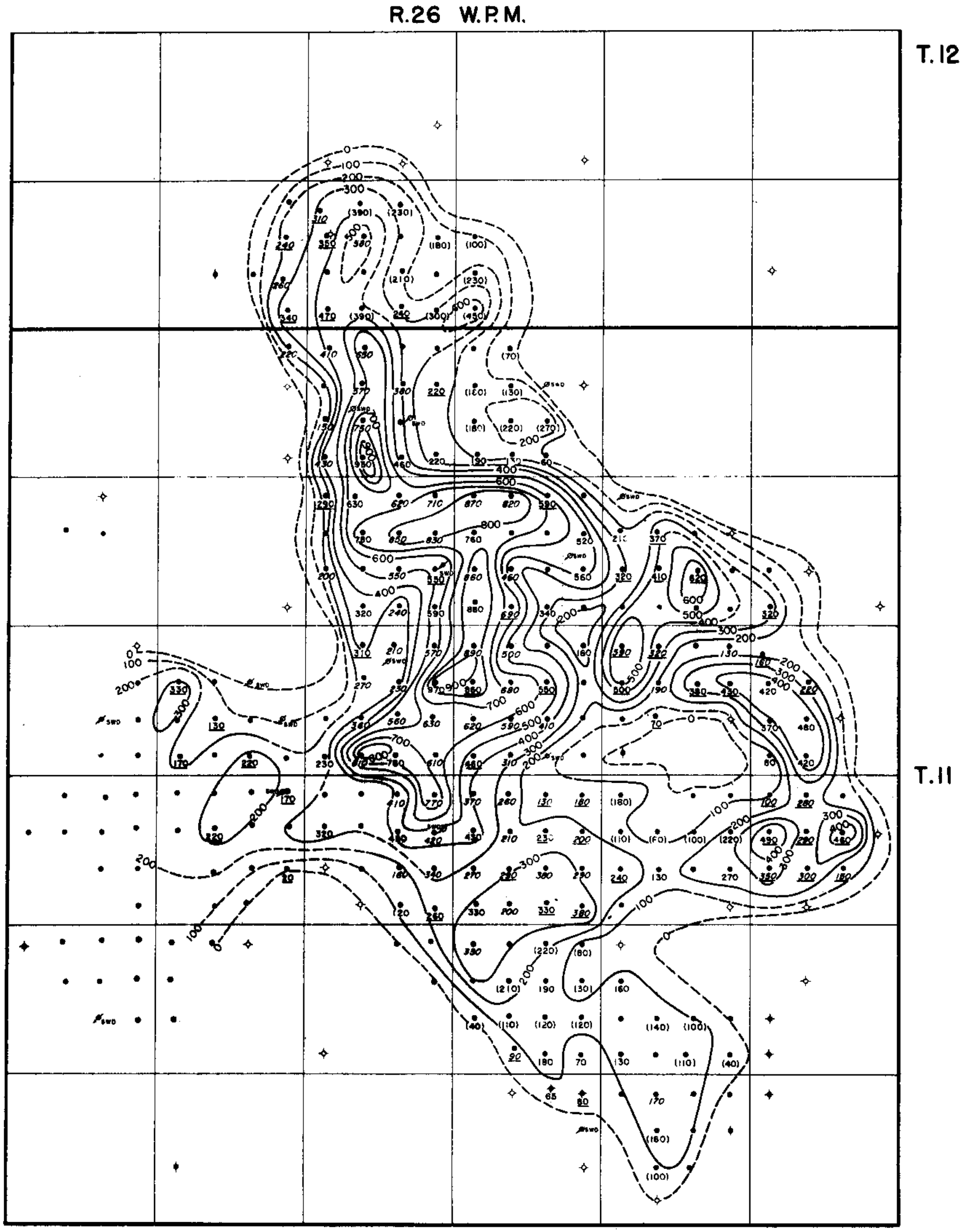


FIGURE 9

NORTH VIRDEN SCALLION FIELD

CHERTY ZONE

ESTIMATED NET POROSITY THICKNESS

C. I. 100 POROSITY - FEET

SCALE IN MILES

0 1 2

MAY, 1961

LEGEND

- 240 CORE ANALYSIS VALUE
- 360 M.L. VALUE
- 325 CORED AND ANALYZED THROUGH BASE OF EFFECTIVE OIL SATURATION (NO EXTRAPOLATION REQUIRED)
- 324 M.L. VALUES - NO EXTRAPOLATION REQUIRED.
- (121) VALUE OBTAINED BY OTHER MEANS.

OOLITIC ZONE DISCREPANCIES

Well 16-3	Isopach shows	12.2' pay
	Core Analysis	13.6' pay
2-15	Isopach shows	6.4' pay
	Core Analysis	7.1' pay
2-20	Isopach shows	8.0' pay
	Core Analysis	6.7' pay

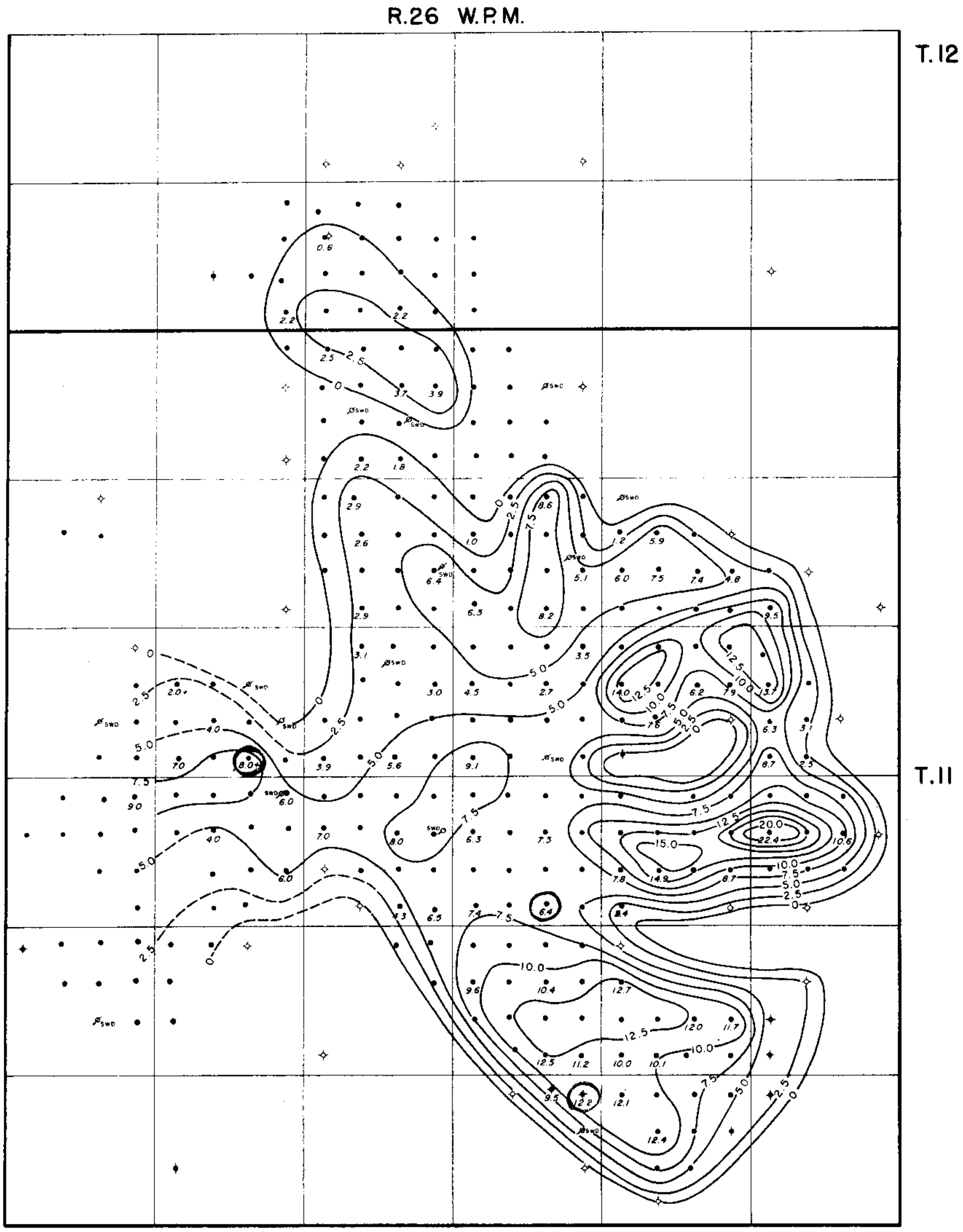


FIGURE 10

NORTH VIRDEN SCALLION FIELD

OOLITIC ZONE

ISOPACH OF ESTIMATED NET EFFECTIVE PAY

(FROM CORE ANALYSIS)

C.I. 2.5 FT.

SCALE IN MILES

0 1 2

MAY, 1961

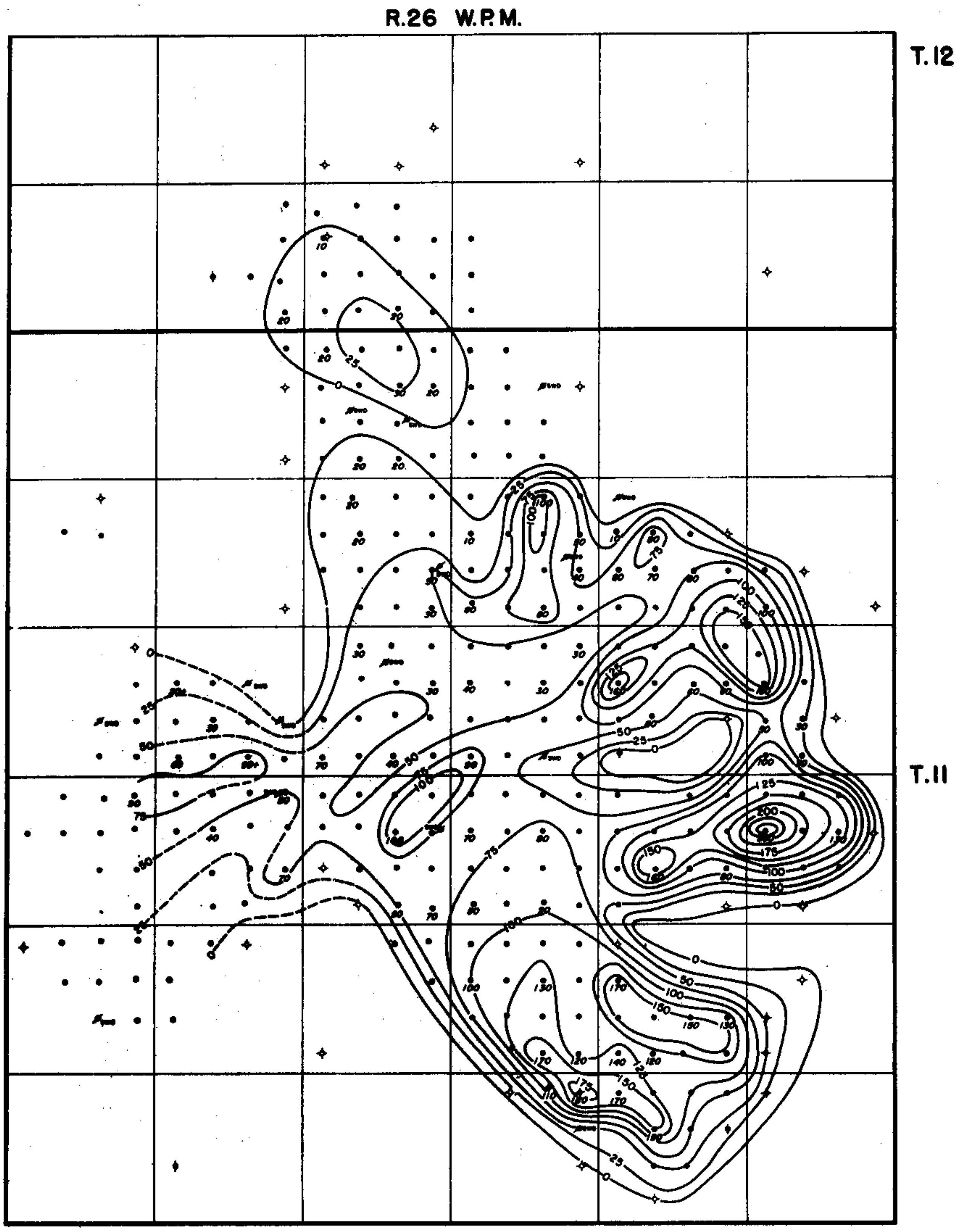


FIGURE II

NORTH VIRDEN SCALLION FIELD

OOLITIC ZONE

ESTIMATED NET POROSITY THICKNESS

C.I. 25 POROSITY - FEET

SCALE IN MILES

0 2

MAY, 1961

CRINOIDAL ZONE DISCREPANCIES

Well 11-2	Isopach shows	11' pay
	Core Analysis	8.4' pay
2-10	Isopach shows	5' pay
	Core Analysis	6' pay
4-15	Isopach shows	12' pay
	Core Analysis	10.2' pay
2-20	Isopach shows	18' pay
	Core Analysis	16.1' pay

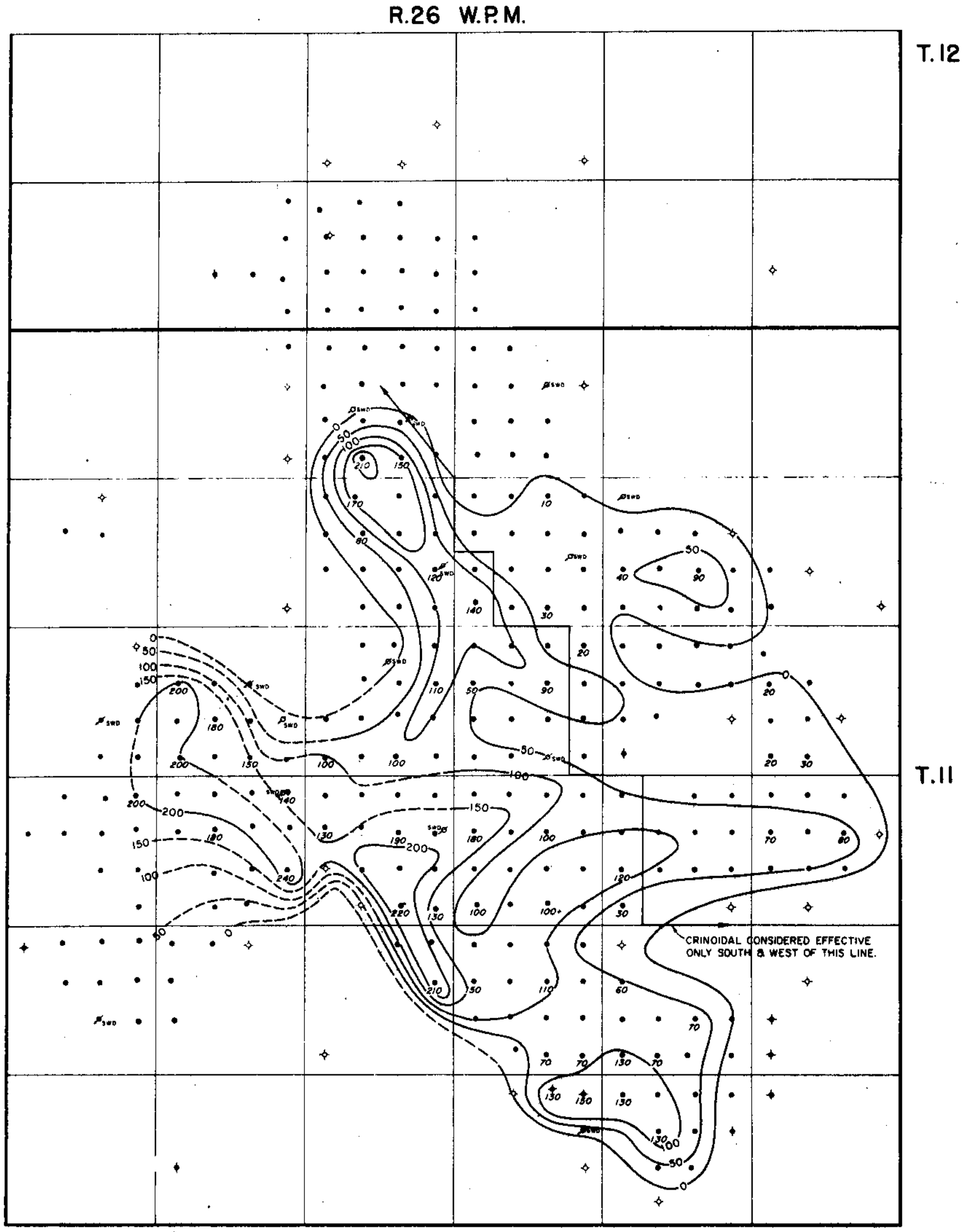


FIGURE 13

NORTH VIRDEN SCALLION FIELD

CRINOIDAL MEMBER

ESTIMATED NET POROSITY THICKNESS

C. I. 50 POROSITY FEET

SCALE IN MILES

0 2

MAY, 1961

Reservoir Study
NVS field, MB.
The California Standard
Company

August 1961

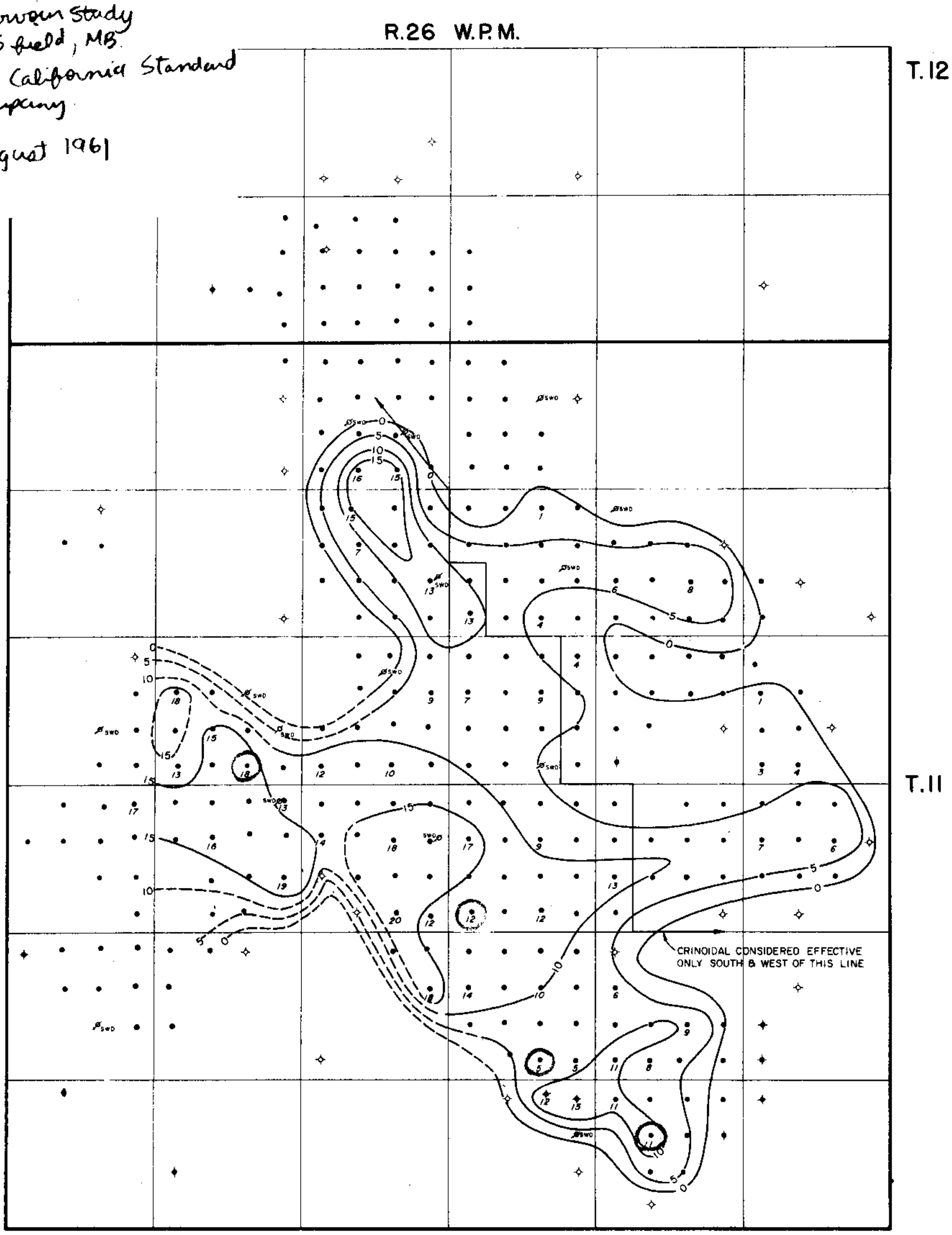


FIGURE 12

NORTH VIRDEN SCALLION FIELD

CRINOIDAL MEMBER

ISOPACH OF ESTIMATED NET EFFECTIVE PAY

(FROM CORE ANALYSIS)

C. I. 5 FT.

SCALE IN MILES

0 1 2

MAY, 1961

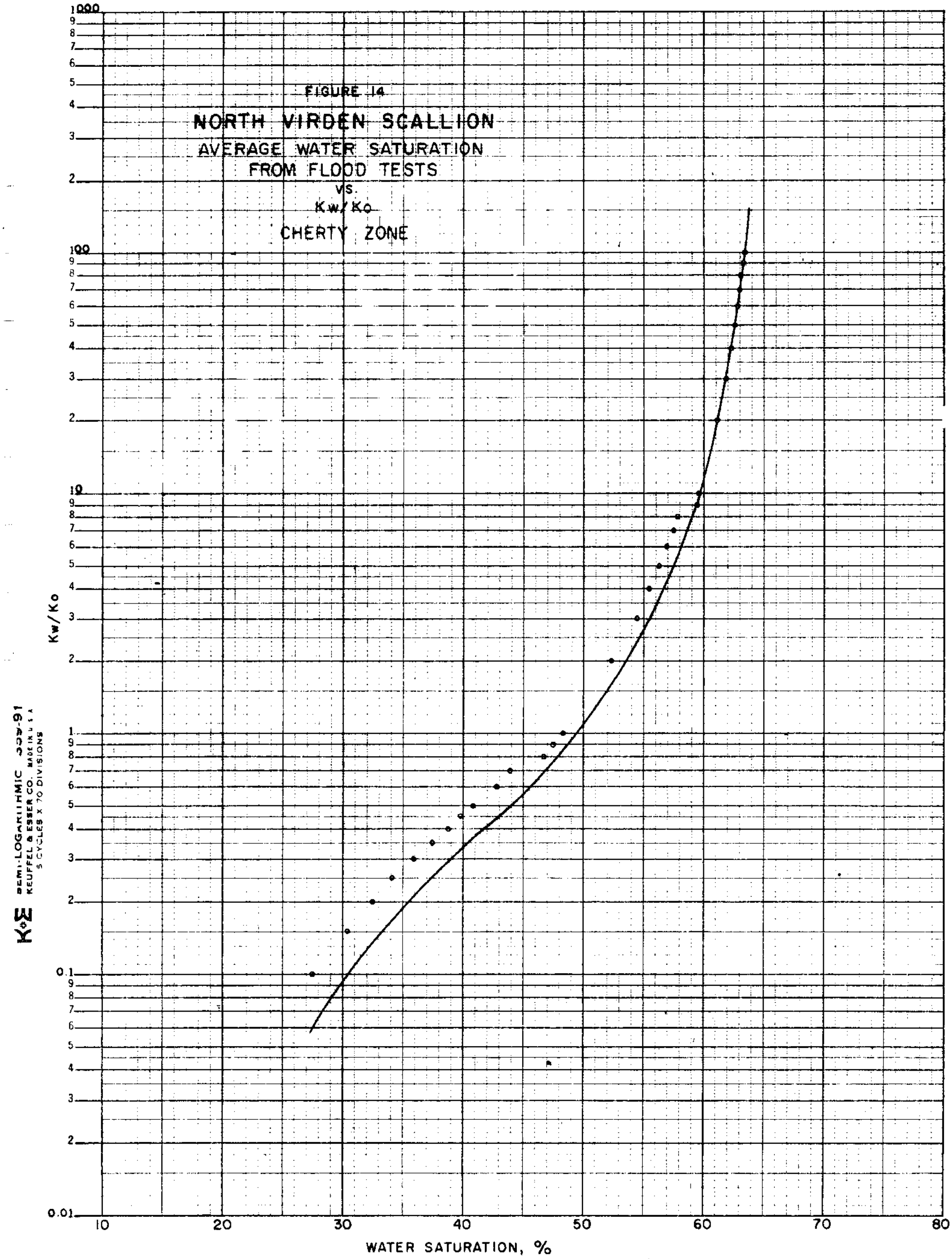
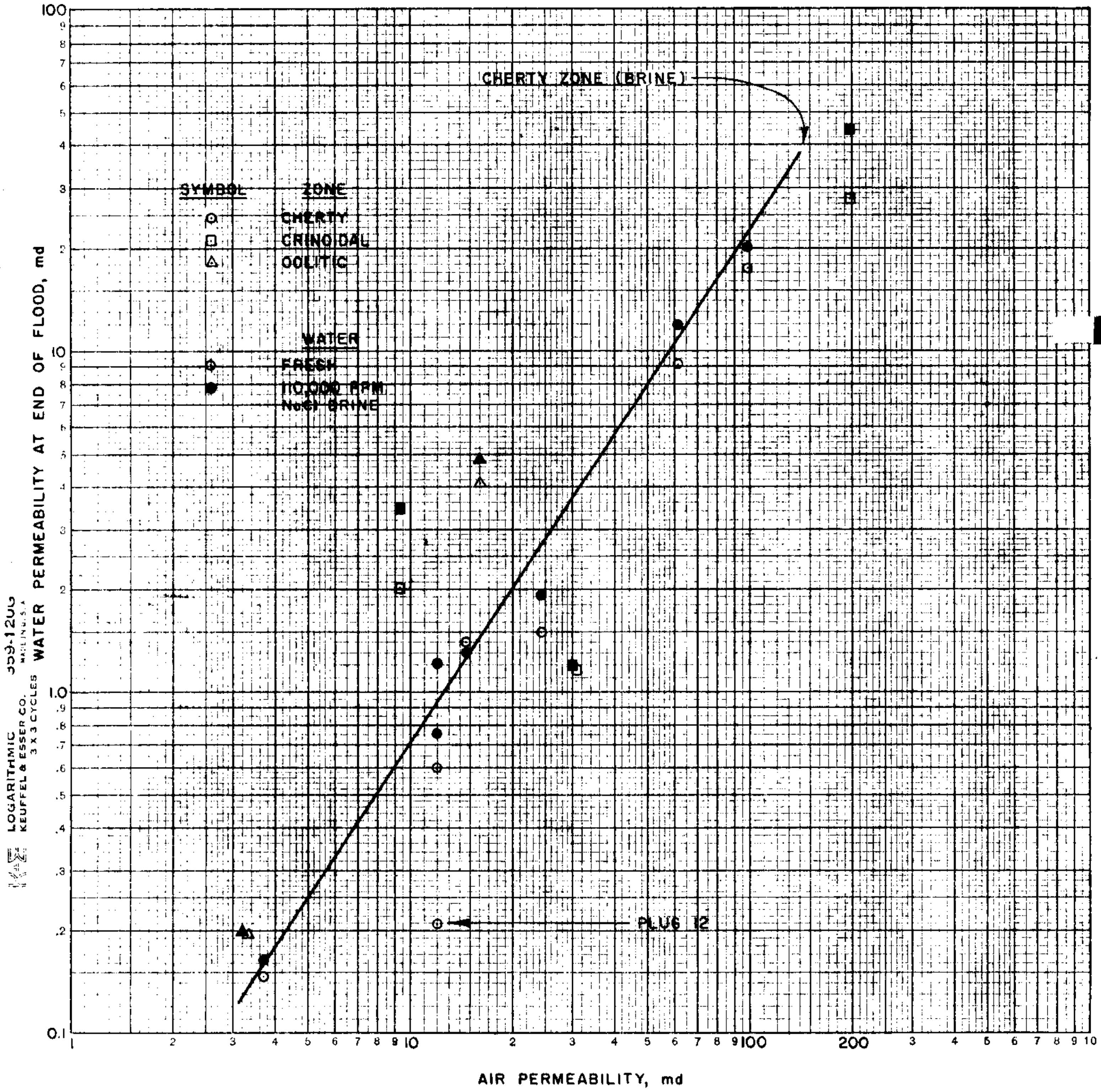


FIGURE 14
NORTH VIRDEN SCALLION
AVERAGE WATER SATURATION
FROM FLOOD TESTS
VS.
Kw/Ko
CHERTY ZONE
Kw/Ko
WATER SATURATION, %
1000
100
10
1
0.1
0.01
10
20
30
40
50
60
70
80
K&E SEMI-LOGARITHMIC 359-91
KEUFFEL & ESSER CO. MADE IN U.S.A.
5 CYCLES X 70 DIVISIONS

FIGURE 15

NORTH VIRDEN SCALLION

BRINE AND FRESH WATER PERMEABILITIES
AT END OF FLOOD vs. AIR PERMEABILITY



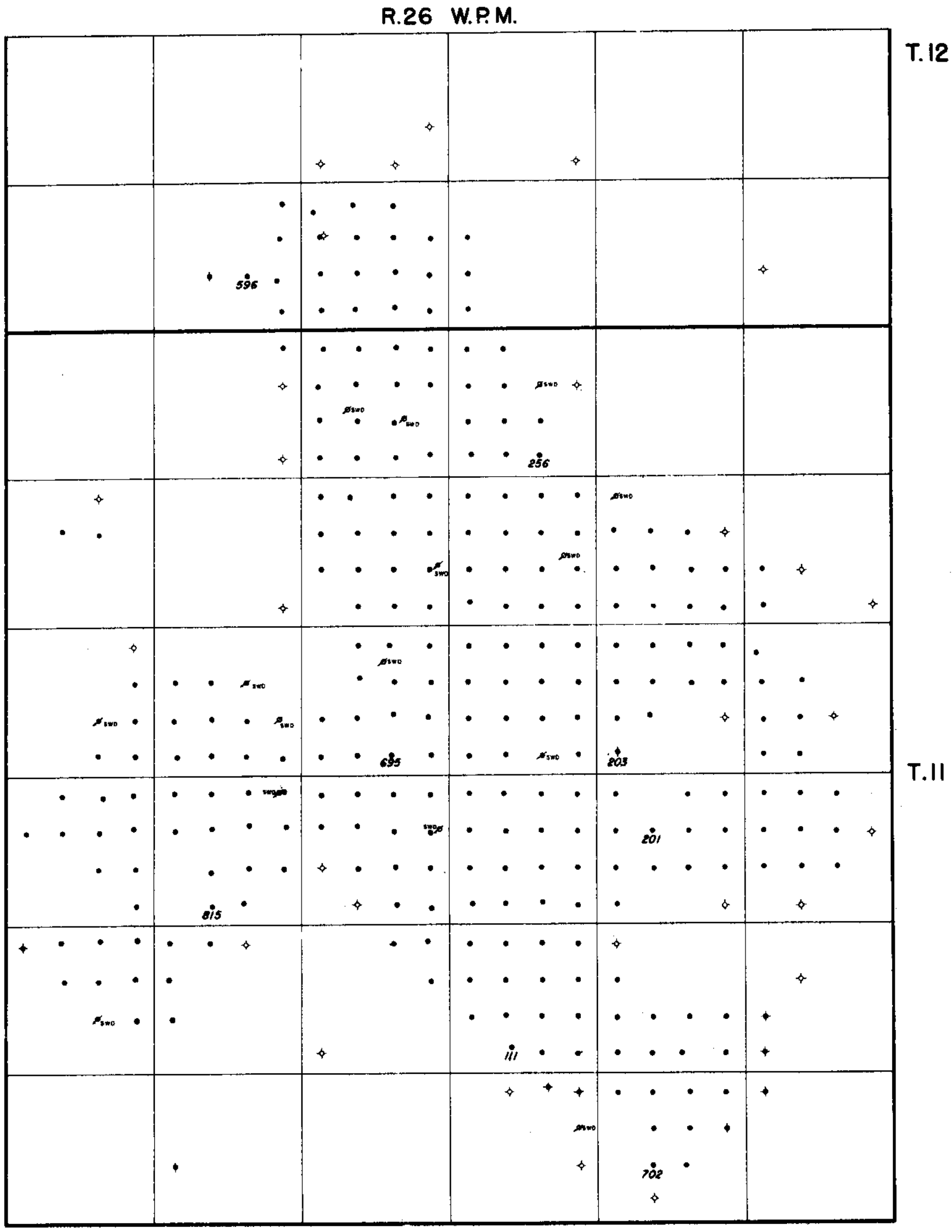


FIGURE 16

NORTH VIRDEN SCALLION FIELD

SUBSURFACE PRESSURE SURVEY
MAY 1961

SCALE IN MILES

0 2

MAY, 1961

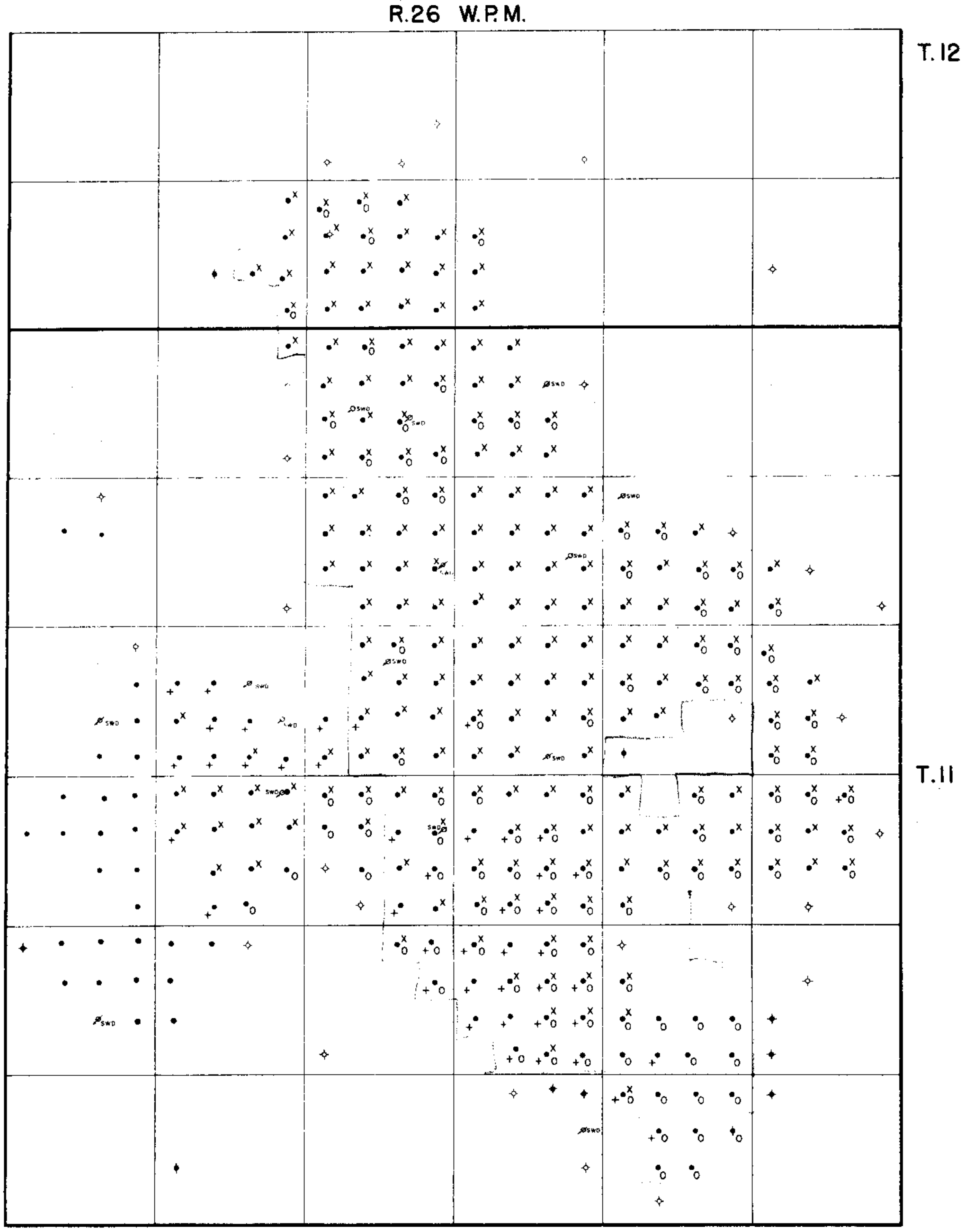


FIGURE 17

NORTH VIRDEN SCALLION FIELD

SHOWING

ZONE OF COMPLETIONS

LEGEND

X CHERTY ZONE
O OOLITIC ZONE
+ CRINOIDAL ZONE

SCALE IN MILES
0 2

MAY, 1961

FIGURE 18

NORTH VIRDEN SCALLION-UNIT AREA

TOTAL PRODUCTION RATE vs. CUMULATIVE

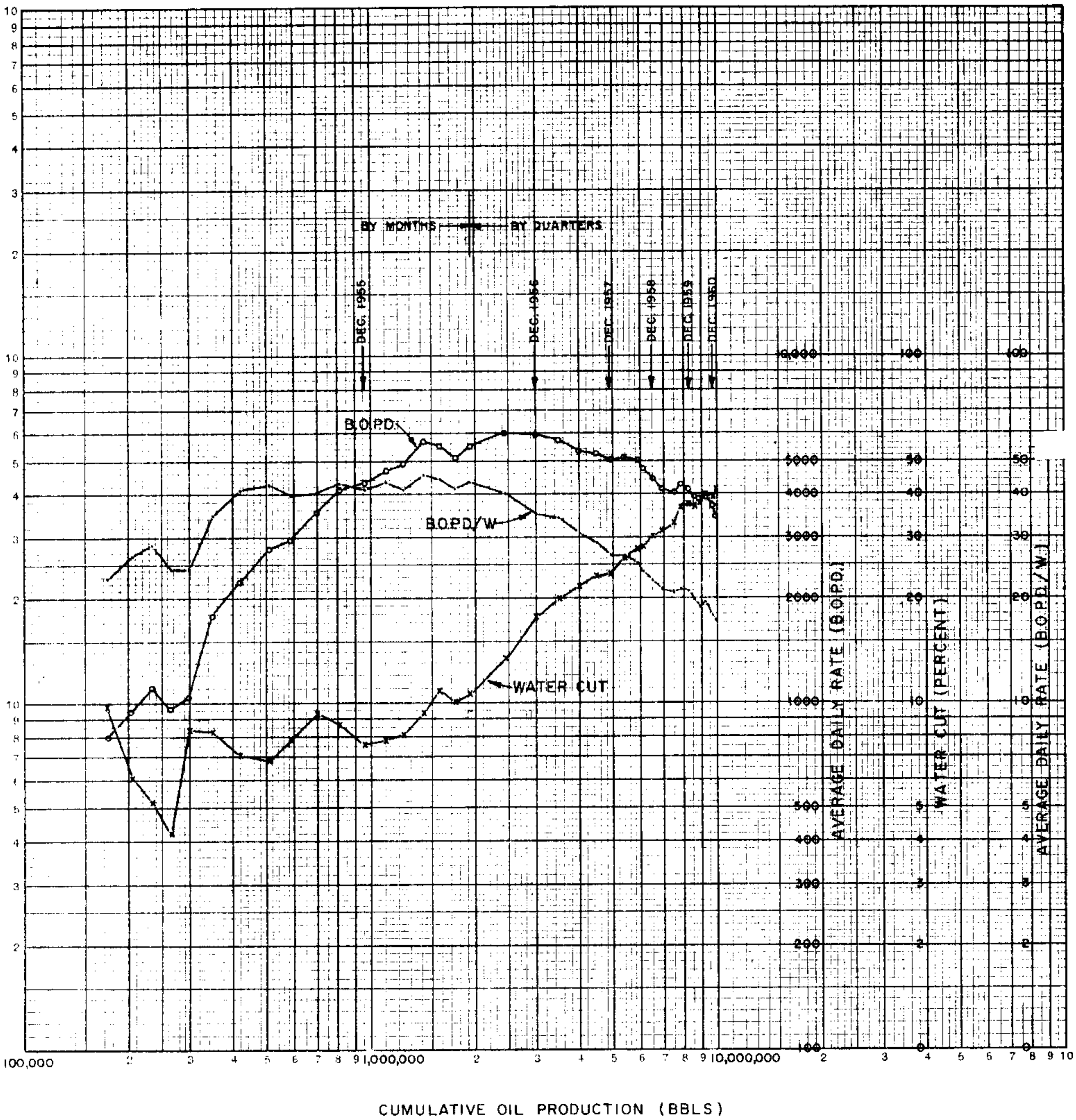
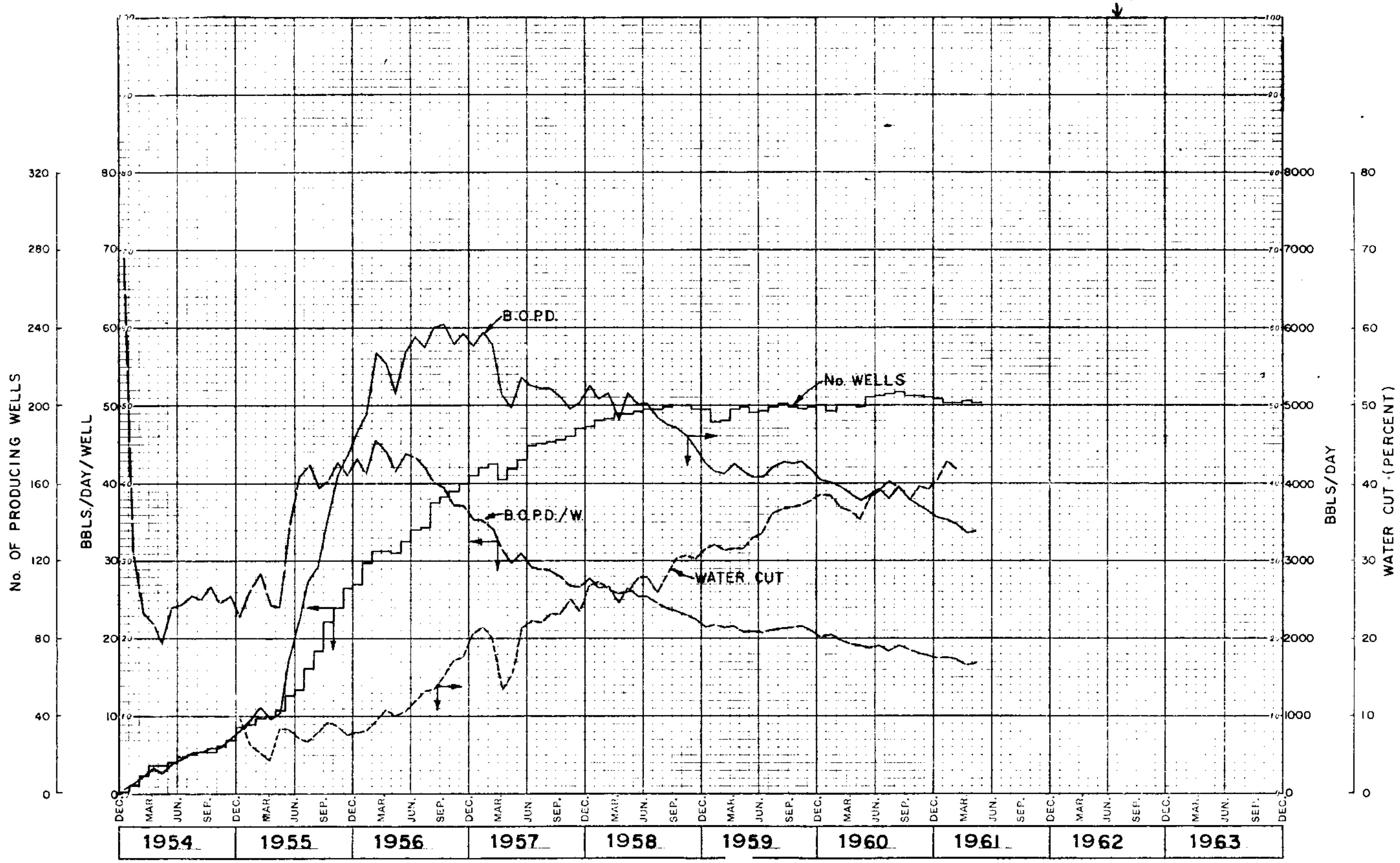


FIGURE 19

NORTH VIRDEN SCALLION - UNIT AREA

TOTAL PRODUCTION RATE vs. TIME



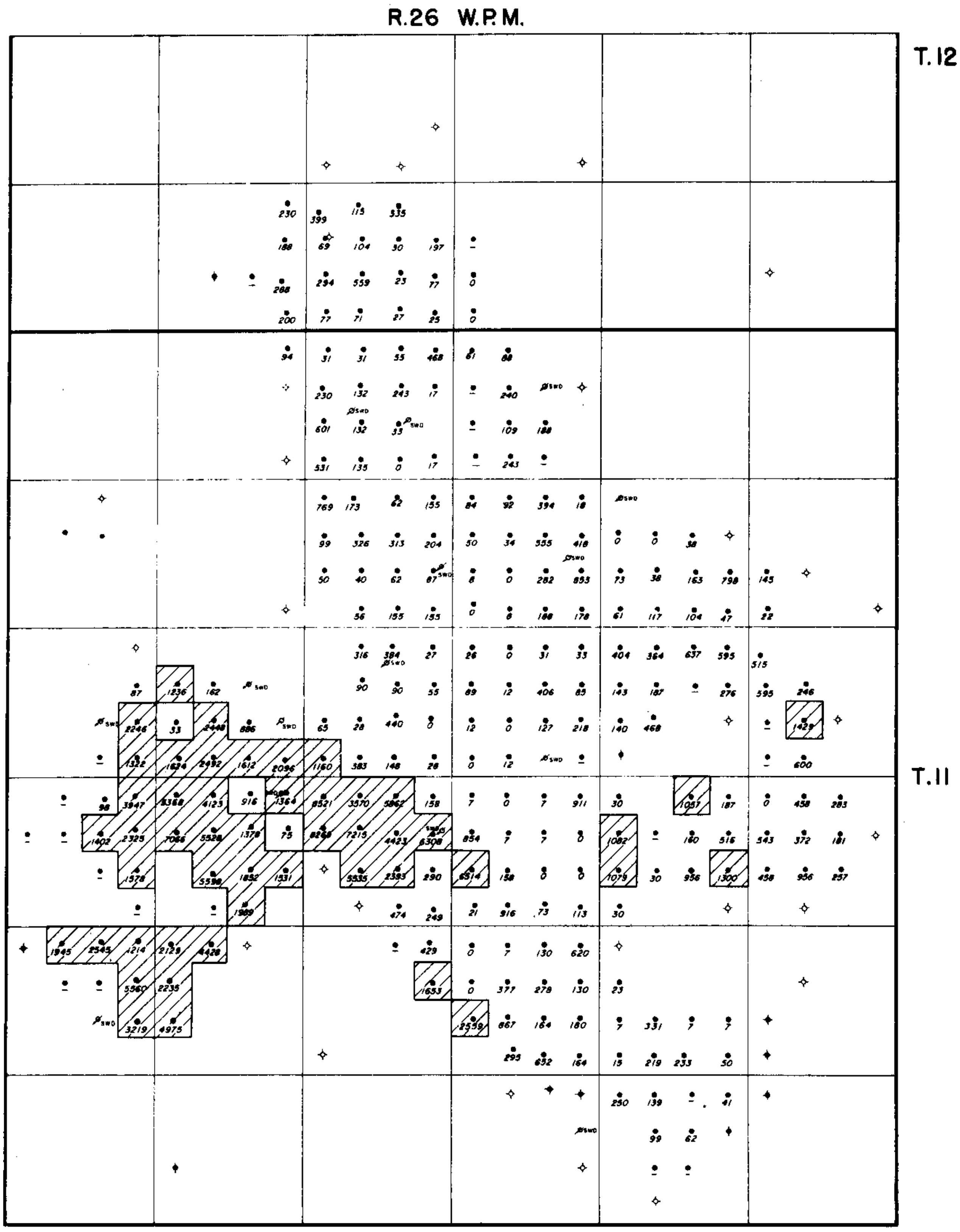


FIGURE 20

NORTH VIRDEN SCALLION FIELD

WATER PRODUCTION MAP

BARRELS PER MONTH

APRIL 1961

OVER 1000 BBLS./MONTH

SCALE IN MILES

0 1 2

MAY, 1961

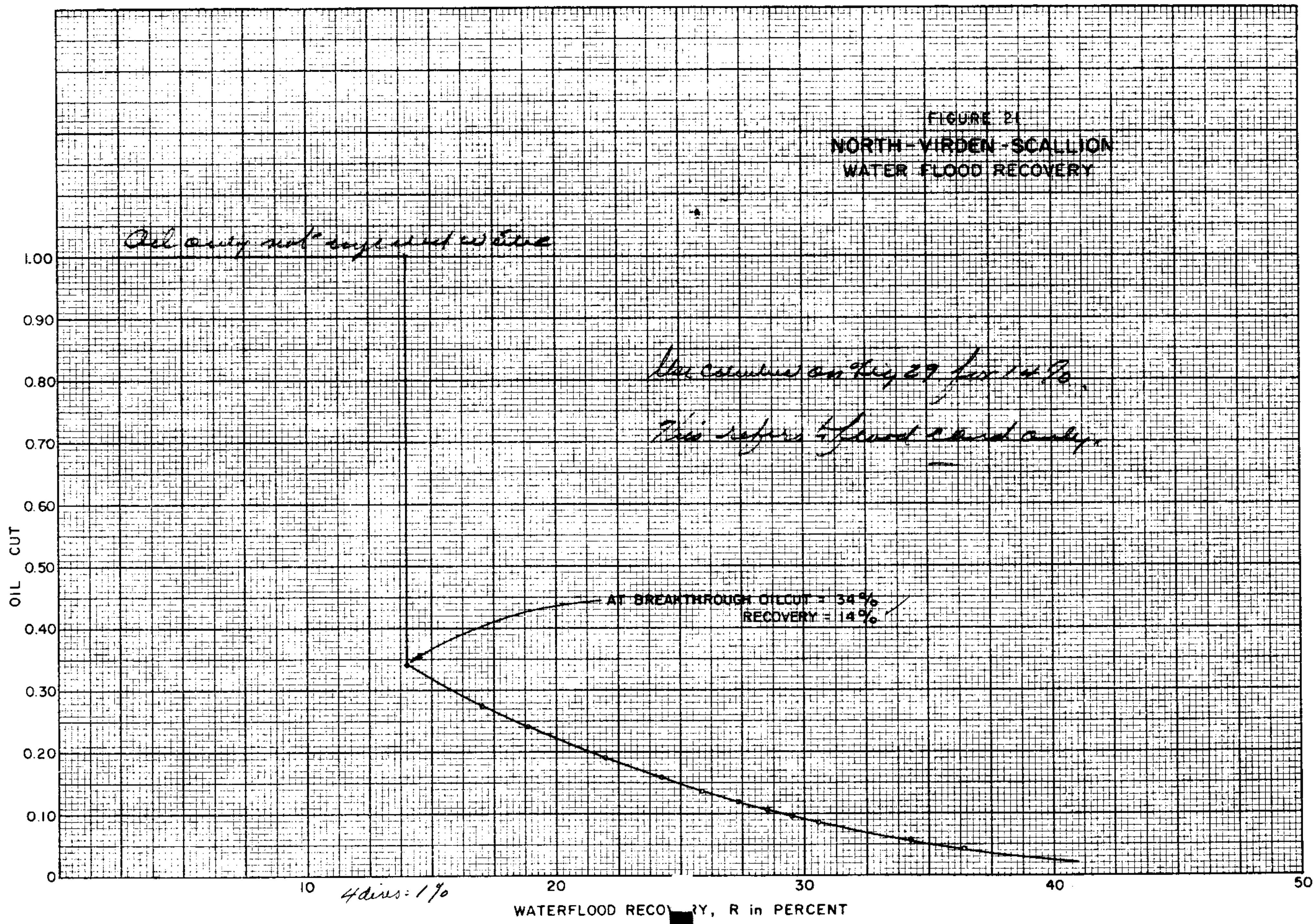


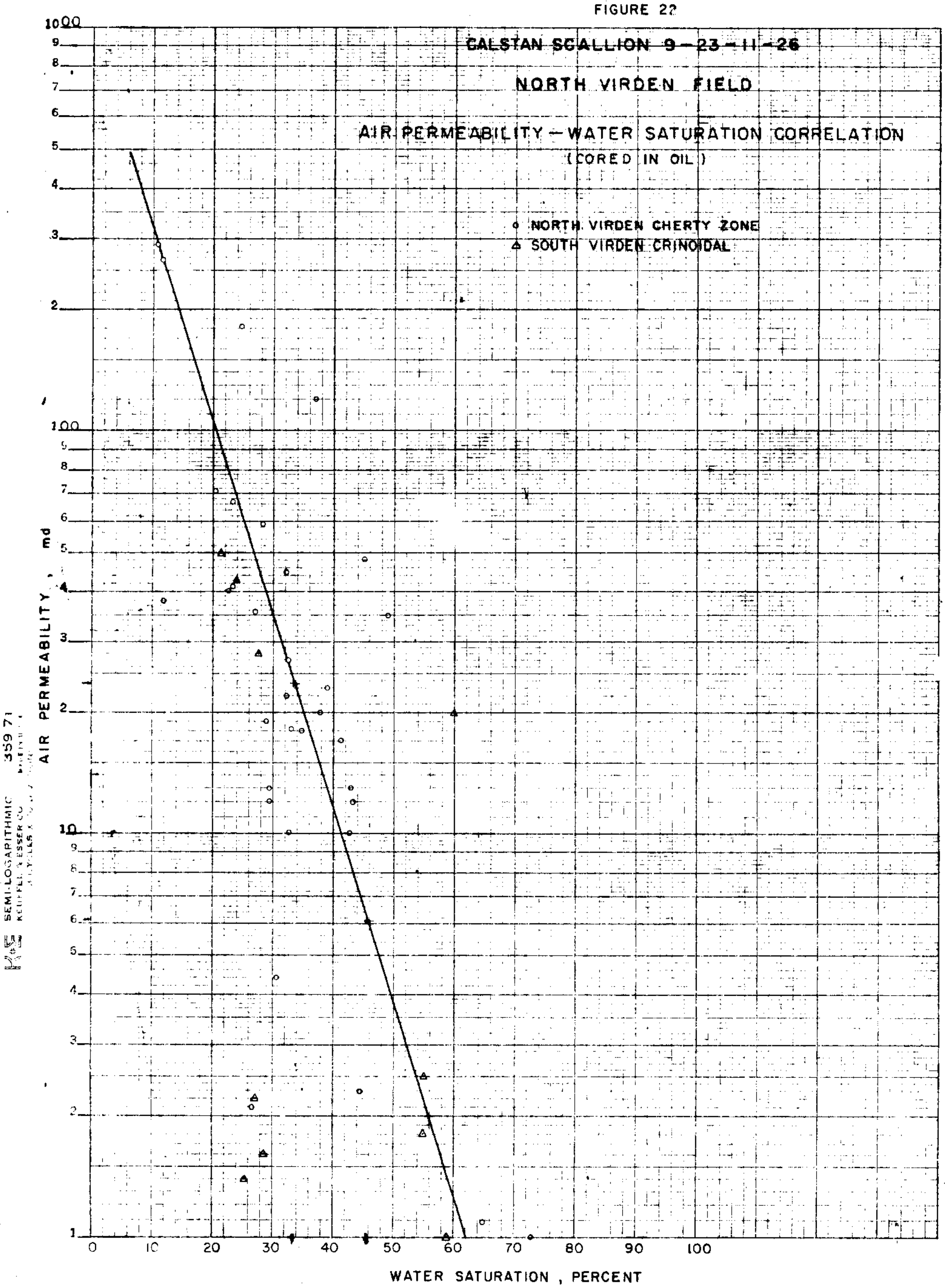
FIGURE 21
NORTH - VIRDEN - SCALLION
WATER FLOOD RECOVERY
AT BREAKTHROUGH OILCUT = 34%
RECOVERY = 14%
OIL CUT
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0
10
20
30
40
50
4 divs: 1%
WATERFLOOD RECO[redacted]RY, R in PERCENT

AVERAGE PERMEABILITIES

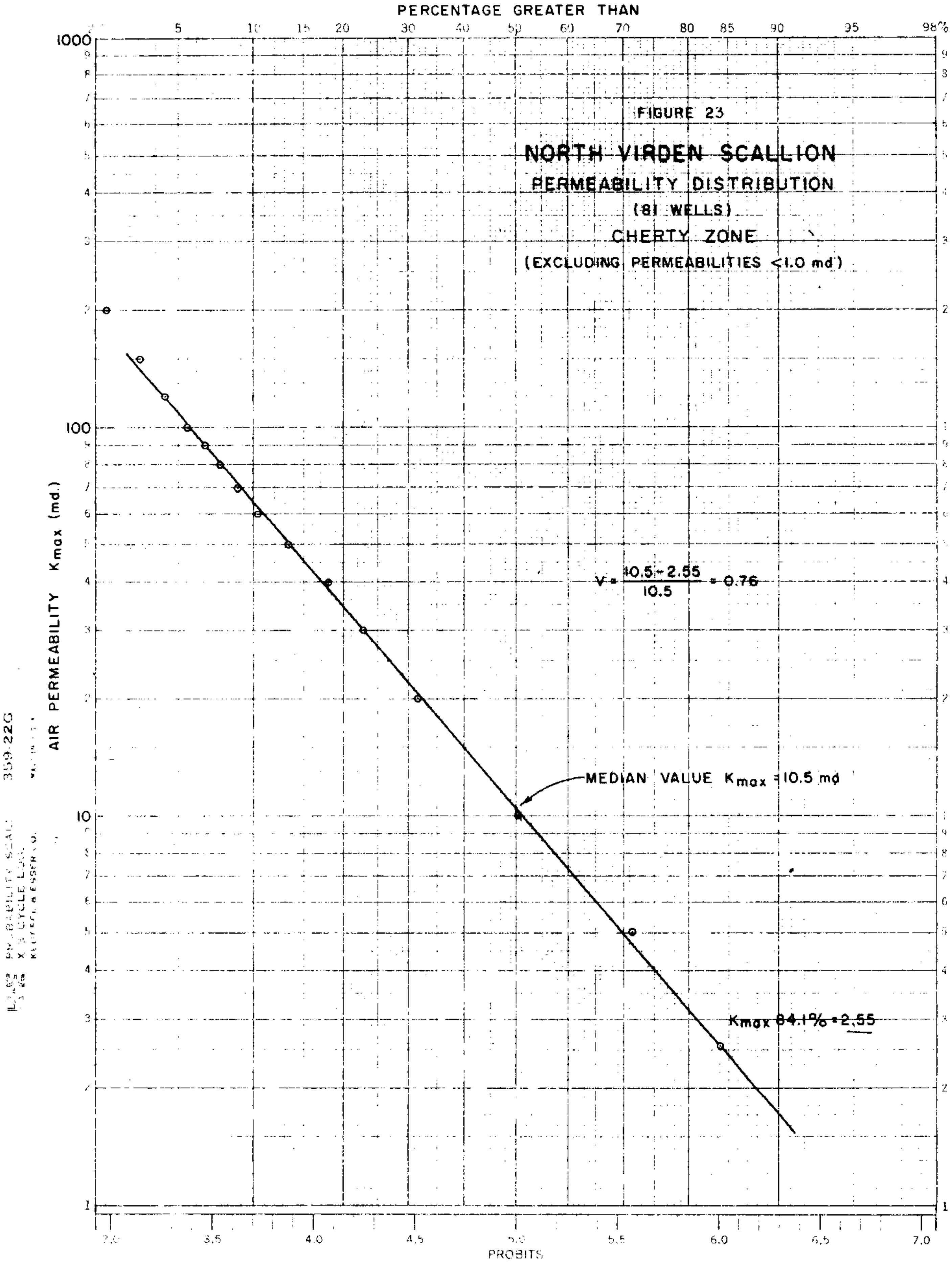
The Average Permeabilities (to air) in the cherty, oolitic, and crinoidal zones are not mentioned in the Reservoir Study - North Virden Scallion Field, Manitoba, dated August, 1961 and are as follows:

Cherty Zone	-	23.4 md
Oolitic Zone	-	112 md
Crinoidal Zone	-	6.1 md

FIGURE 22



[redacted]



PERCENTAGE GREATER THAN
FIGURE 23
NORTH VIRDEN SCALLION
PERMEABILITY DISTRIBUTION
(81 WELLS)
CHERTY ZONE
(EXCLUDING PERMEABILITIES <1.0 md)
AIR PERMEABILITY Kmax (md.)
V = 10.5 − 2.55 / 10.5 = 0.76
MEDIAN VALUE Kmax = 10.5 md
Kmax 84.1% = 2.55
PROBITS
359-22G

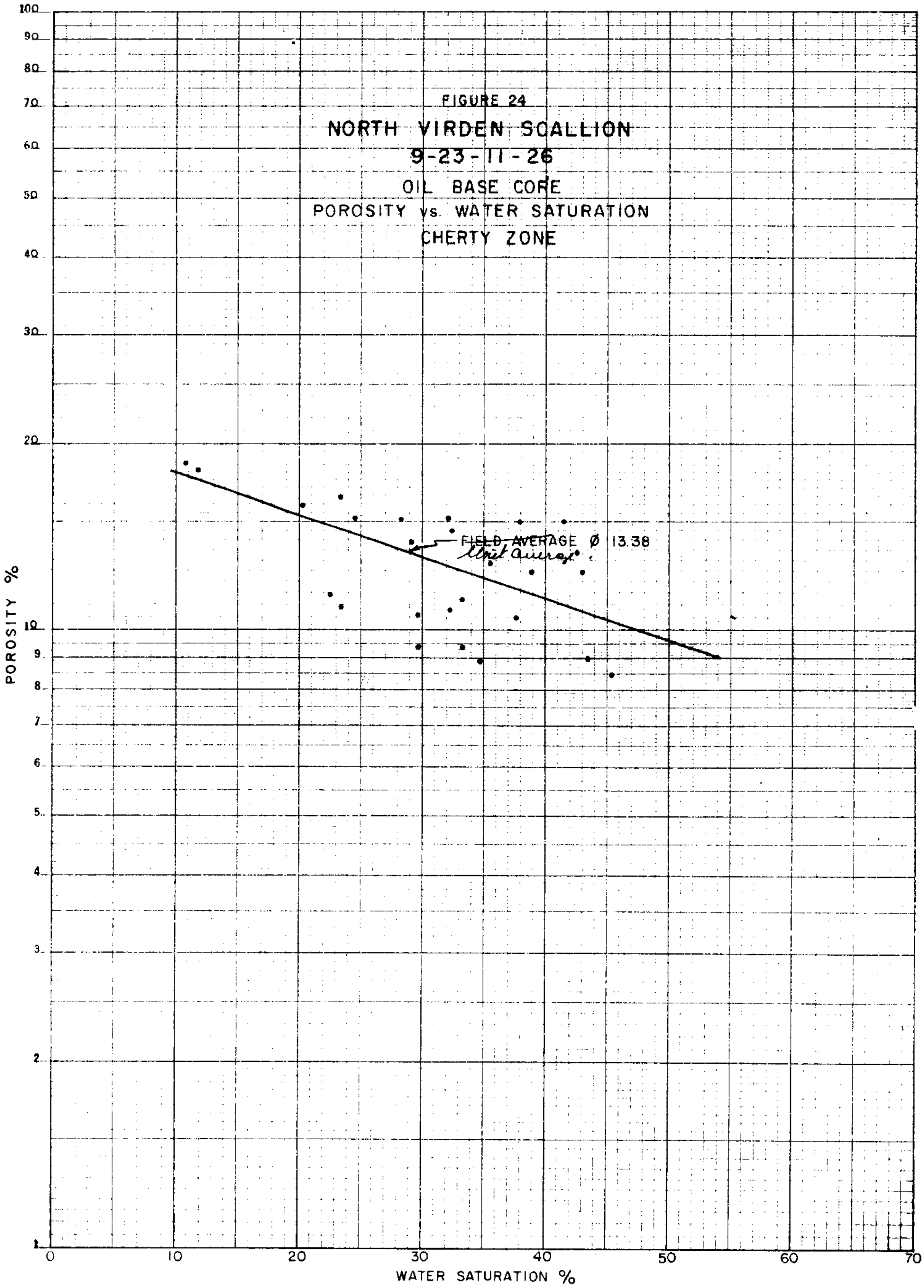
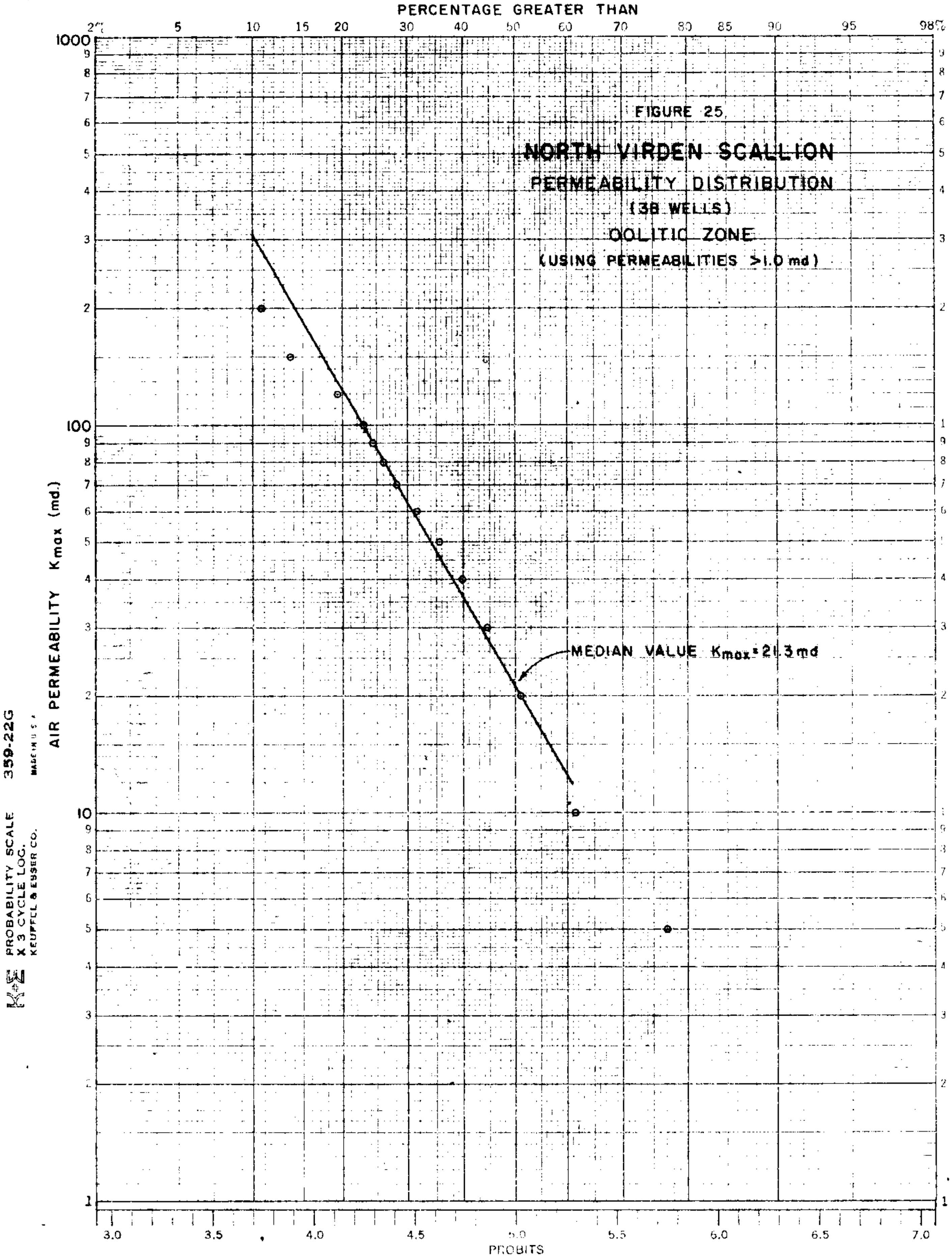


FIGURE 24
NORTH VIRDEN SCALLION
9-23-11-26
OIL BASE CORE
POROSITY vs. WATER SATURATION
CHERTY ZONE
~~FIELD AVERAGE~~ Ø 13.38
Unit average
POROSITY %
WATER SATURATION %
100
90
80
70
60
50
40
30
20
10
9
8
7
6
5
4
3
2
1
0
10
20
30
40
50
60
70

[redacted]



PERCENTAGE GREATER THAN
FIGURE 25
NORTH VIRDEN SCALLION
PERMEABILITY DISTRIBUTION
(38 WELLS)
OOLITIC ZONE
(USING PERMEABILITIES >1.0 md)
MEDIAN VALUE K_{max}=21.3 md
AIR PERMEABILITY K_{max} (md.)
PROBITS
K&E PROBABILITY SCALE X 3 CYCLE LOG. KEUFFEL & ESSER CO.
359-22G
MADE IN U.S.A.

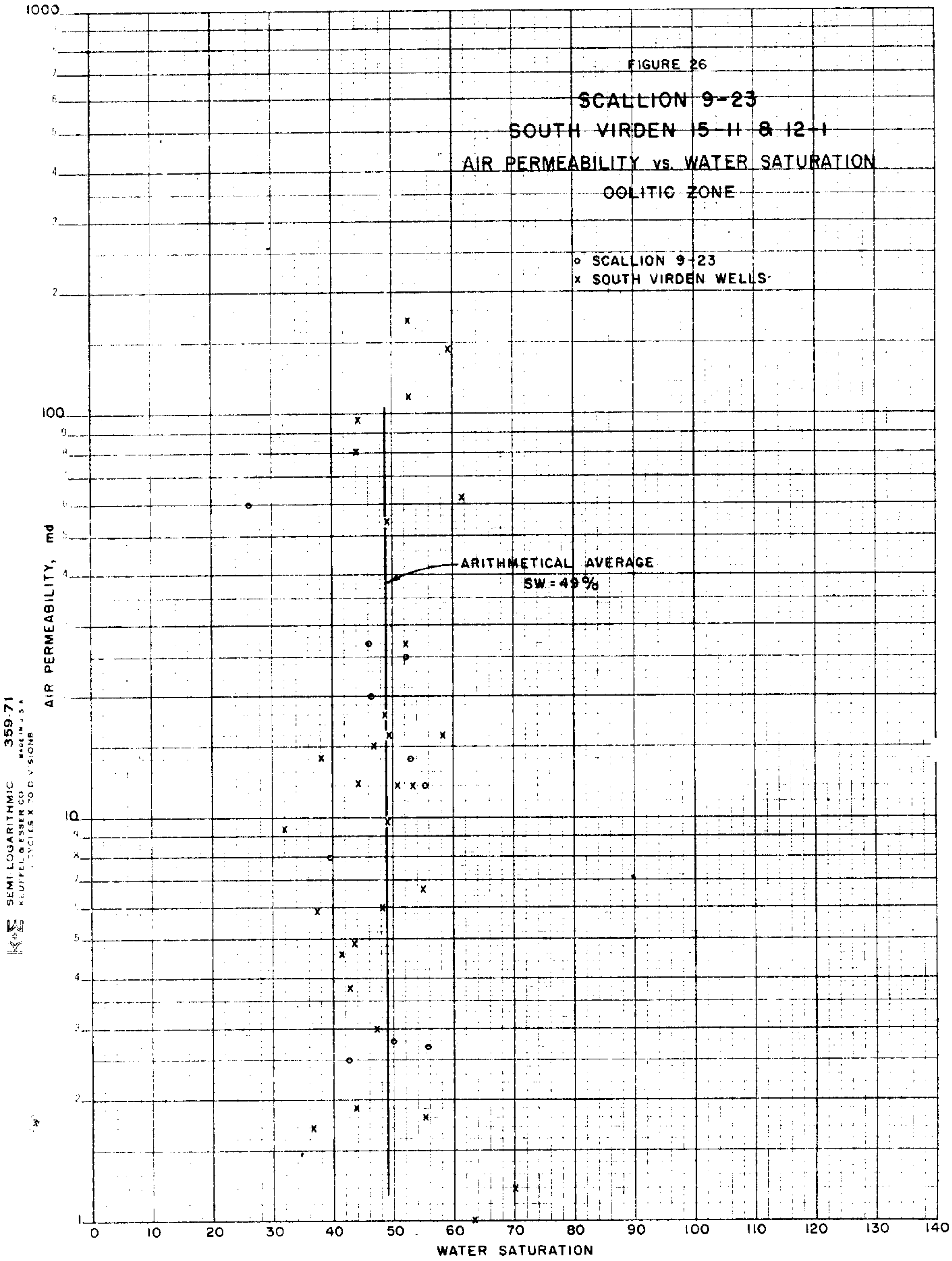


FIGURE 26
SCALLION 9-23
SOUTH VIRDEN 15-11 & 12-1
AIR PERMEABILITY vs. WATER SATURATION
OOLITIC ZONE
o SCALLION 9-23
x SOUTH VIRDEN WELLS
ARITHMETICAL AVERAGE
SW = 49%
AIR PERMEABILITY, md
WATER SATURATION
1000
100
10
1
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
SEMI-LOGARITHMIC 359-71
KEUFFEL & ESSER CO.

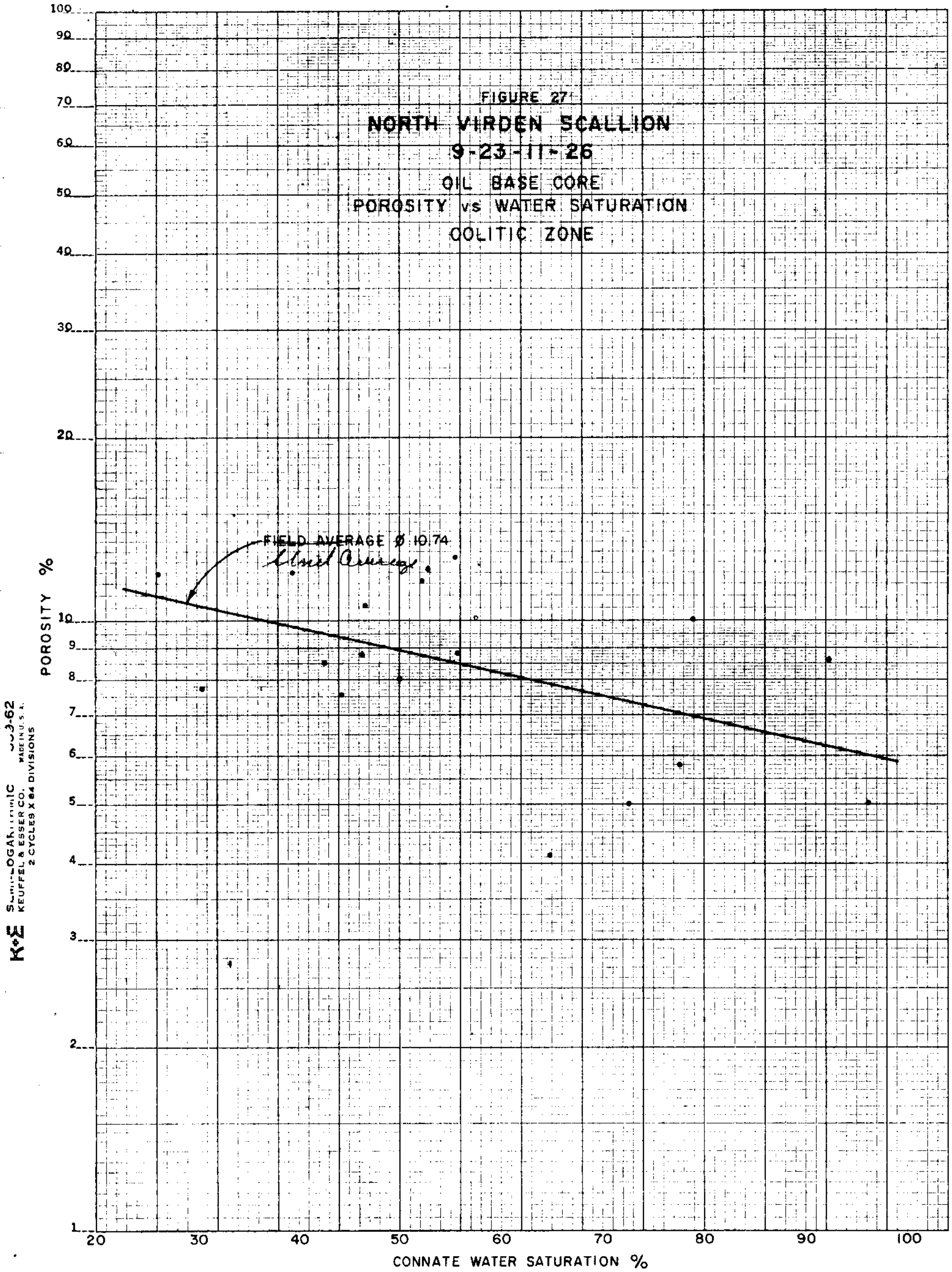


FIGURE 27
NORTH VIRDEN SCALLION
9-23-11-26
OIL BASE CORE
POROSITY vs WATER SATURATION
OOLITIC ZONE
~~FIELD AVERAGE Ø 10.74~~
Unit Average
POROSITY %
CONNATE WATER SATURATION %
100
90
80
70
60
50
40
30
20
10
9
8
7
6
5
4
3
2
1
20
30
40
50
60
70
80
90
100
KEUFFEL & ESSER CO.
2 CYCLES X 84 DIVISIONS

[redacted]

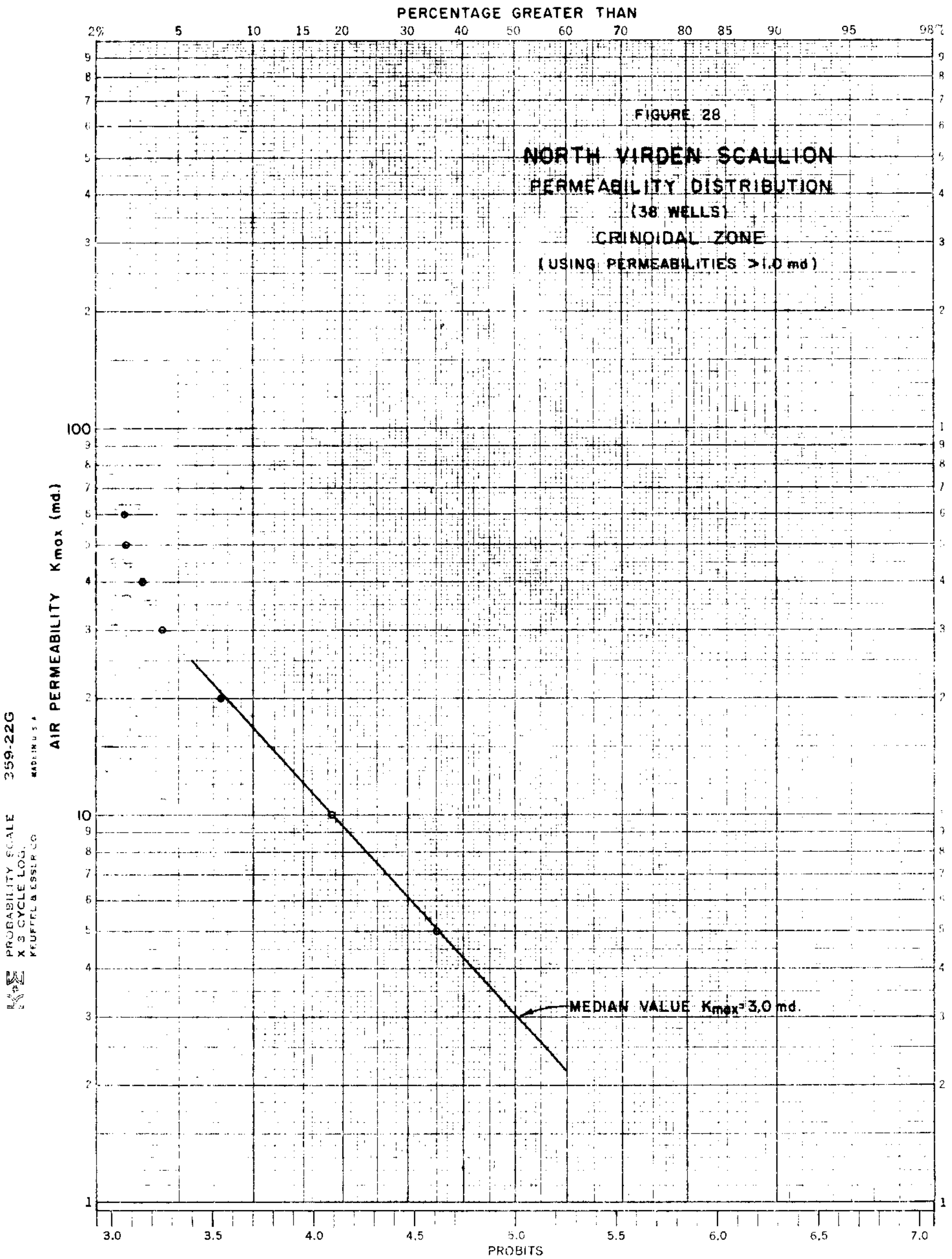


FIGURE 28
NORTH VIRDEN SCALLION
PERMEABILITY DISTRIBUTION
(38 WELLS)
CRINOIDAL ZONE
(USING PERMEABILITIES >1.0 md)
PERCENTAGE GREATER THAN
2% 5 10 15 20 30 40 50 60 70 80 85 90 95 98%
AIR PERMEABILITY Kmax (md.)
100
10
1
MEDIAN VALUE Kmax=3.0 md.
3.0 3.5 4.0 4.5 5.0 5.5 6.0 6.5 7.0
PROBITS
359-22G
PROBABILITY SCALE
X 3 CYCLE LOG.
KEUFFEL & ESSER CO.

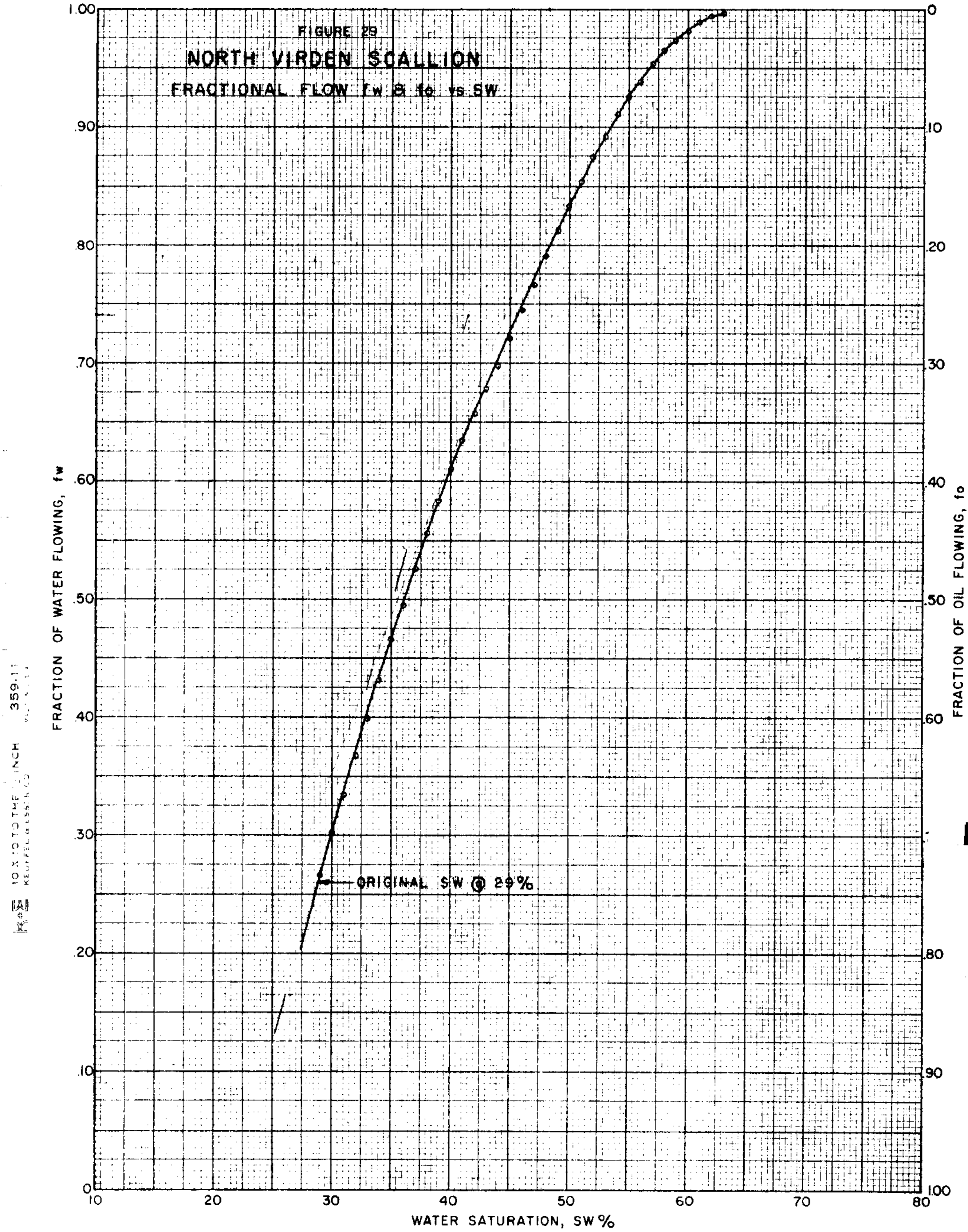


FIGURE 29
NORTH VIRDEN SCALLION
FRACTIONAL FLOW fw & fo vs SW
ORIGINAL SW @ 29%
FRACTION OF WATER FLOWING, fw
FRACTION OF OIL FLOWING, fo
WATER SATURATION, SW%
0
.10
.20
.30
.40
.50
.60
.70
.80
.90
1.00
10
20
30
40
50
60
70
80
90
100
10 X 10 TO THE INCH 359-11

[redacted]

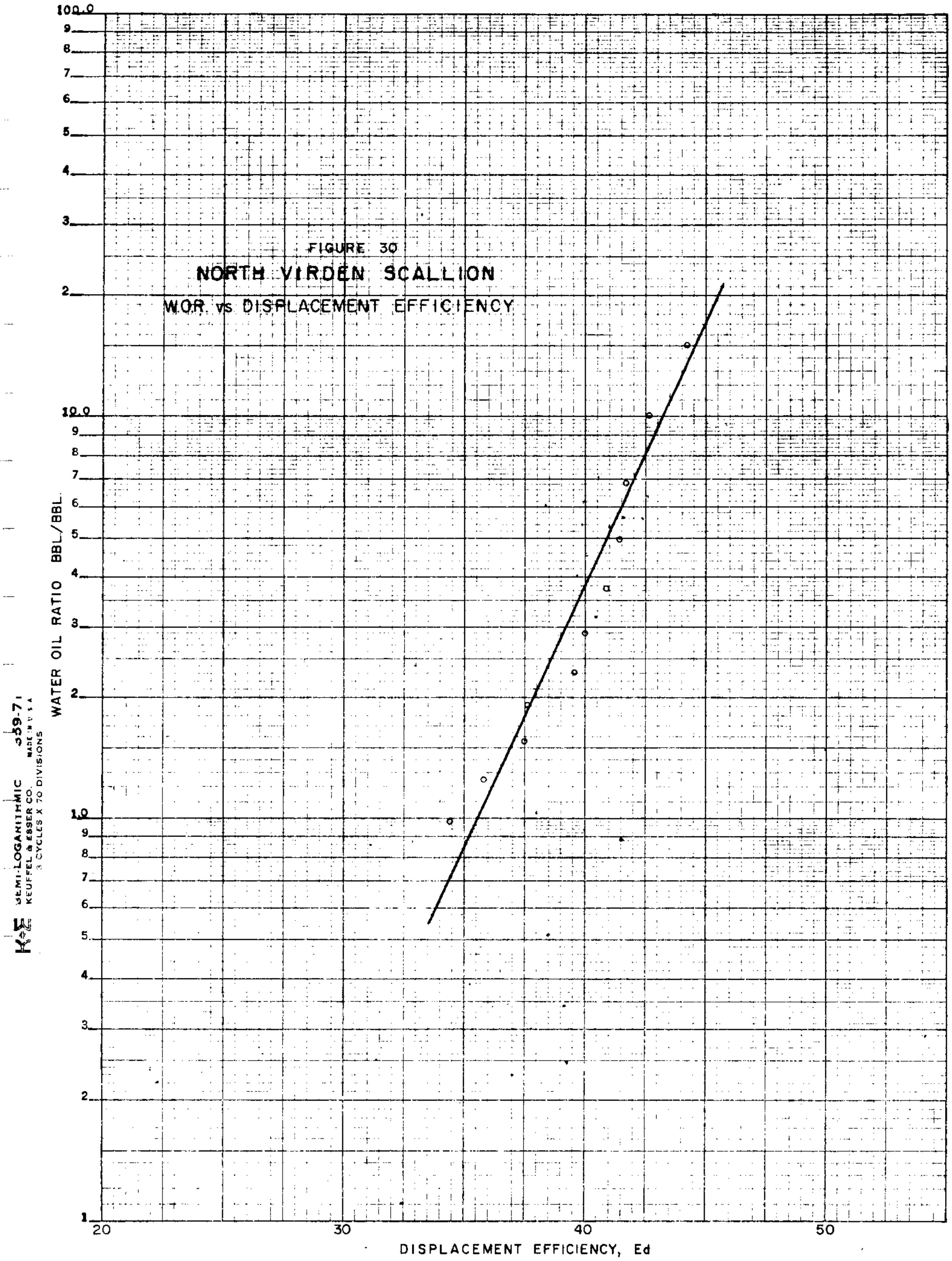
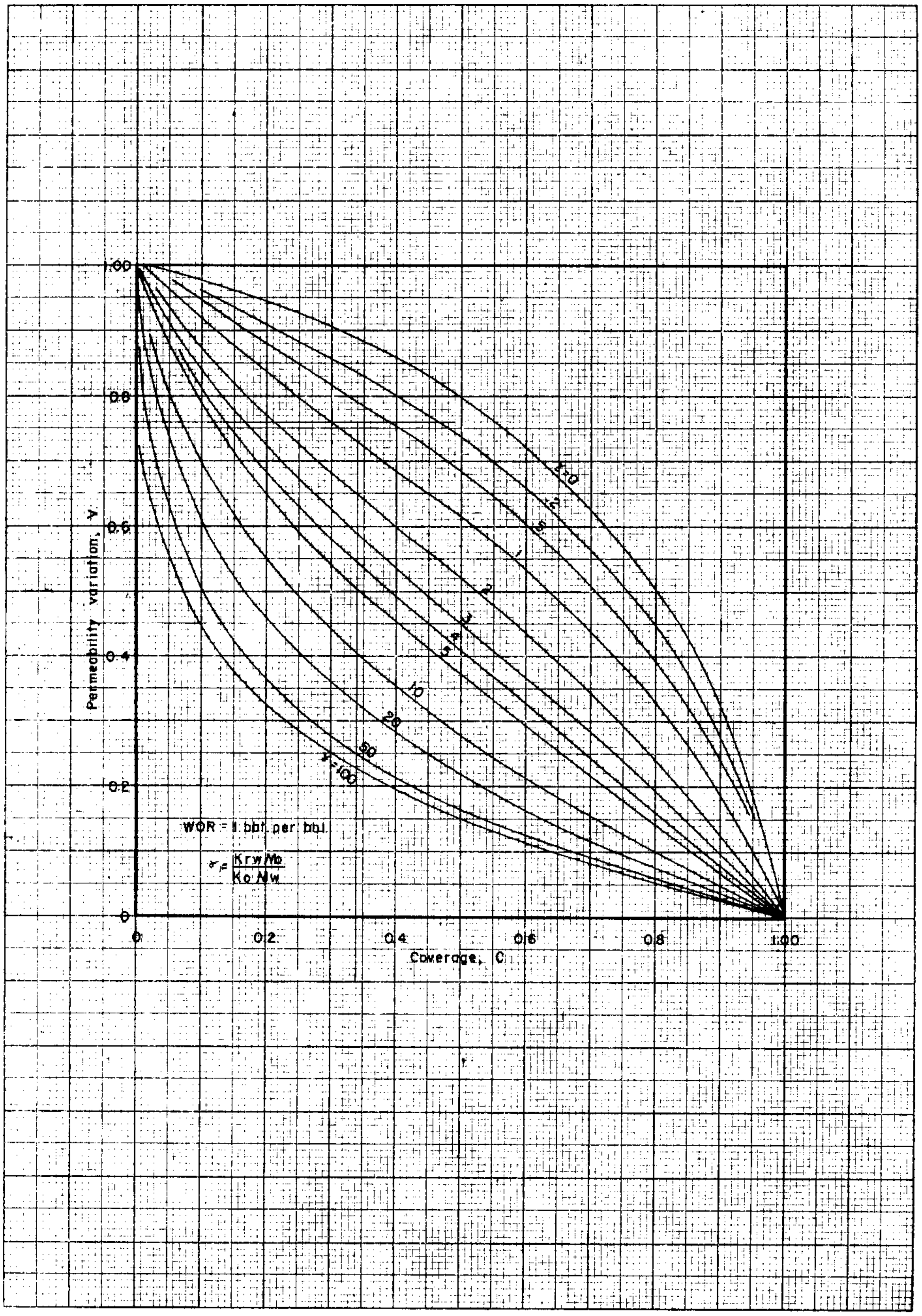


FIGURE 30
NORTH VIRDEN SCALLION
WOR vs DISPLACEMENT EFFICIENCY

DYKSTRA AND PARSON'S WATER FLOOD CALCULATIONS

FIG. 31

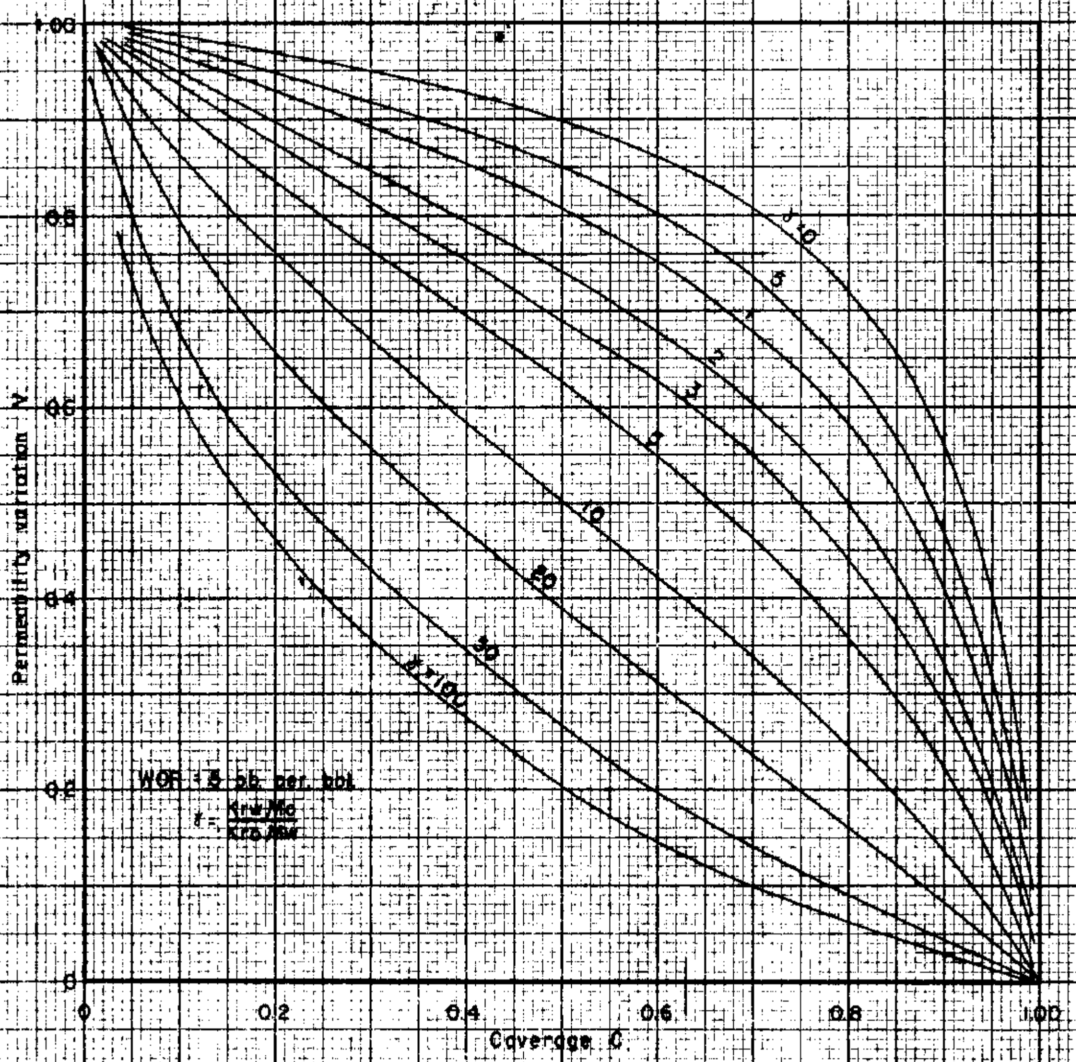
PERMEABILITY VARIATION VS. COVERAGE



DYKSTRA AND PARSON'S WATER FLOOD CALCULATIONS

PERMEABILITY VARIATION VS. COVERAGE

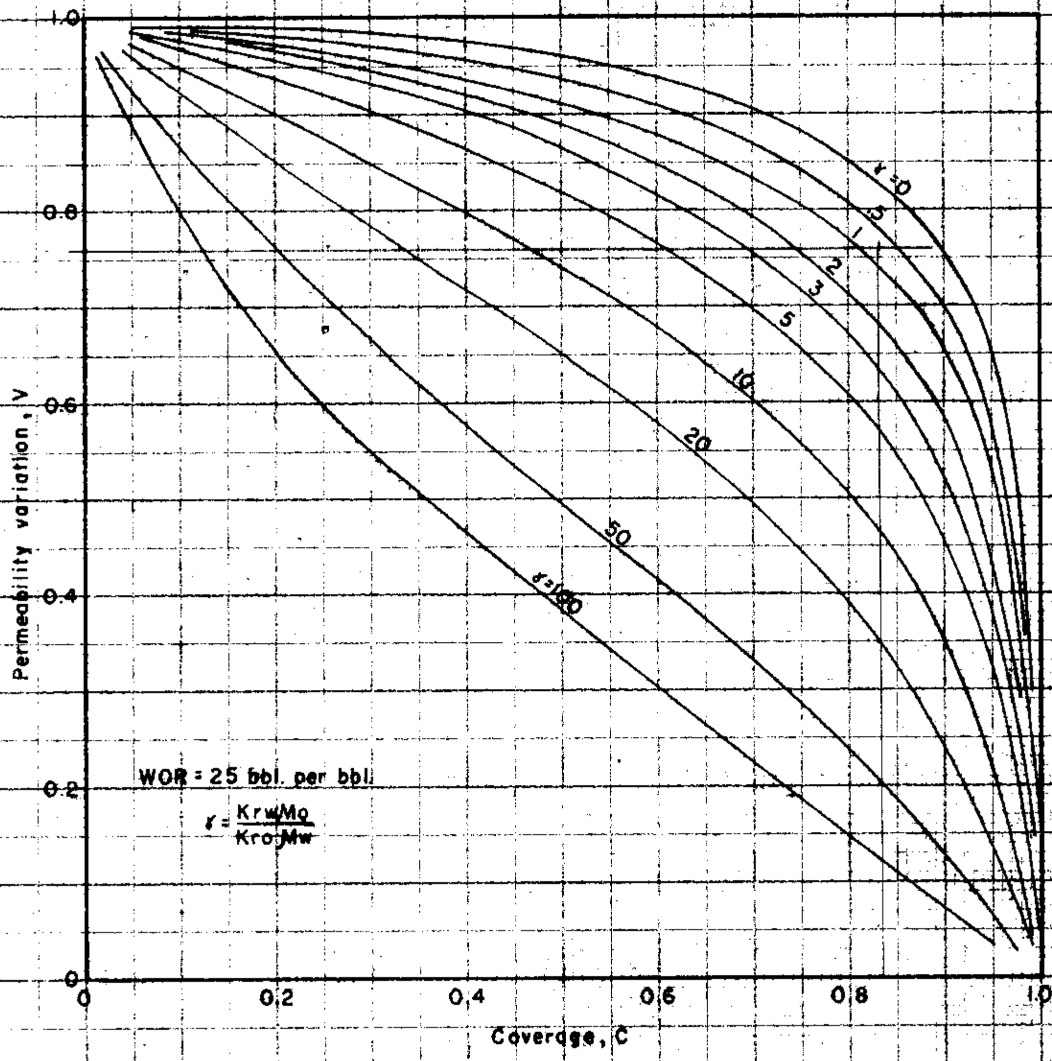
FIG. 32



DYKSTRA AND PARSONS' WATER FLOOD CALCULATIONS

PERMEABILITY VARIATION VS. COVERAGE

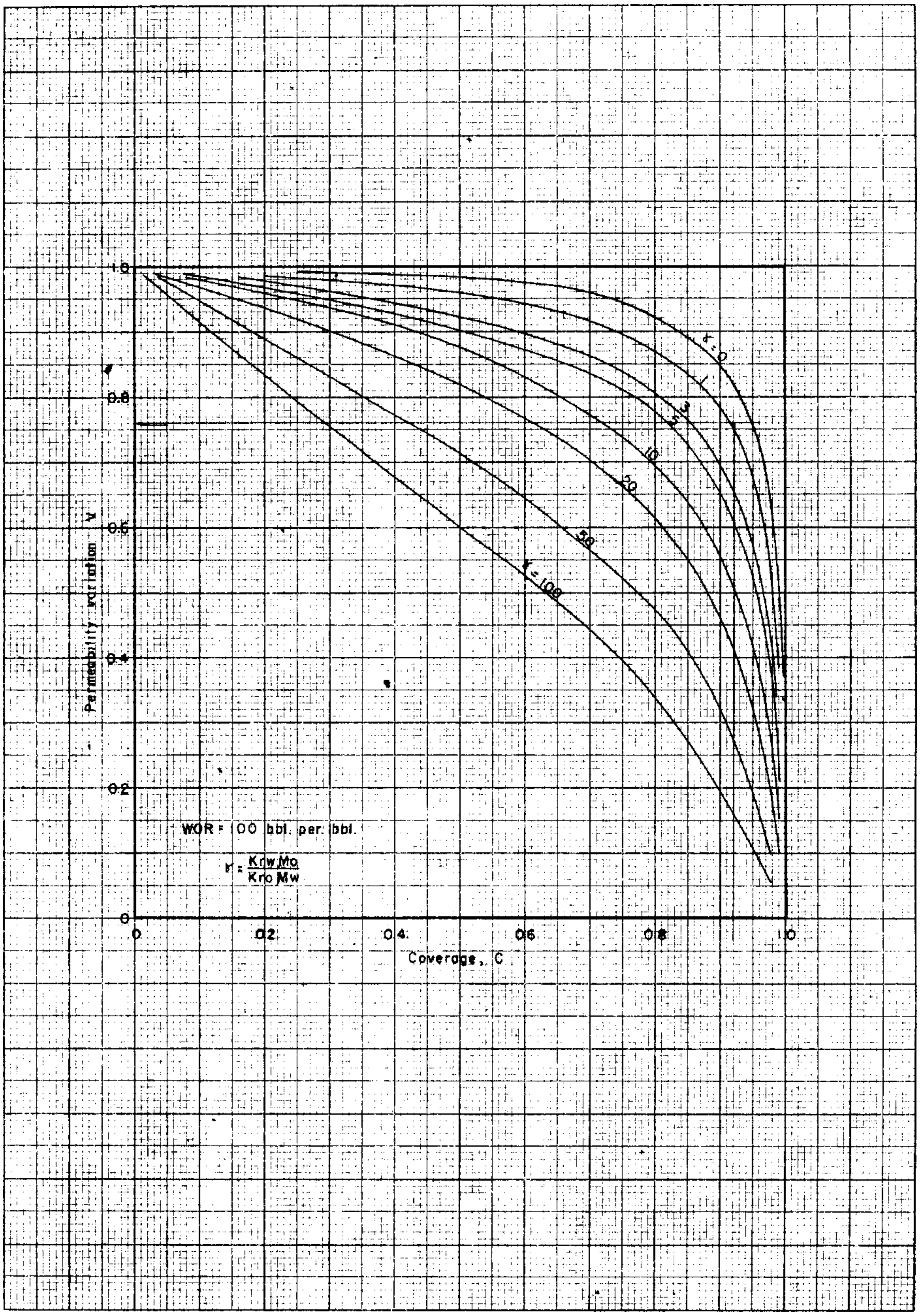
FIG. 33



DYKSTRA AND PARSON'S WATER FLOOD CALCULATIONS

PERMEABILITY VARIATION VS. COVERAGE

FIG. 34

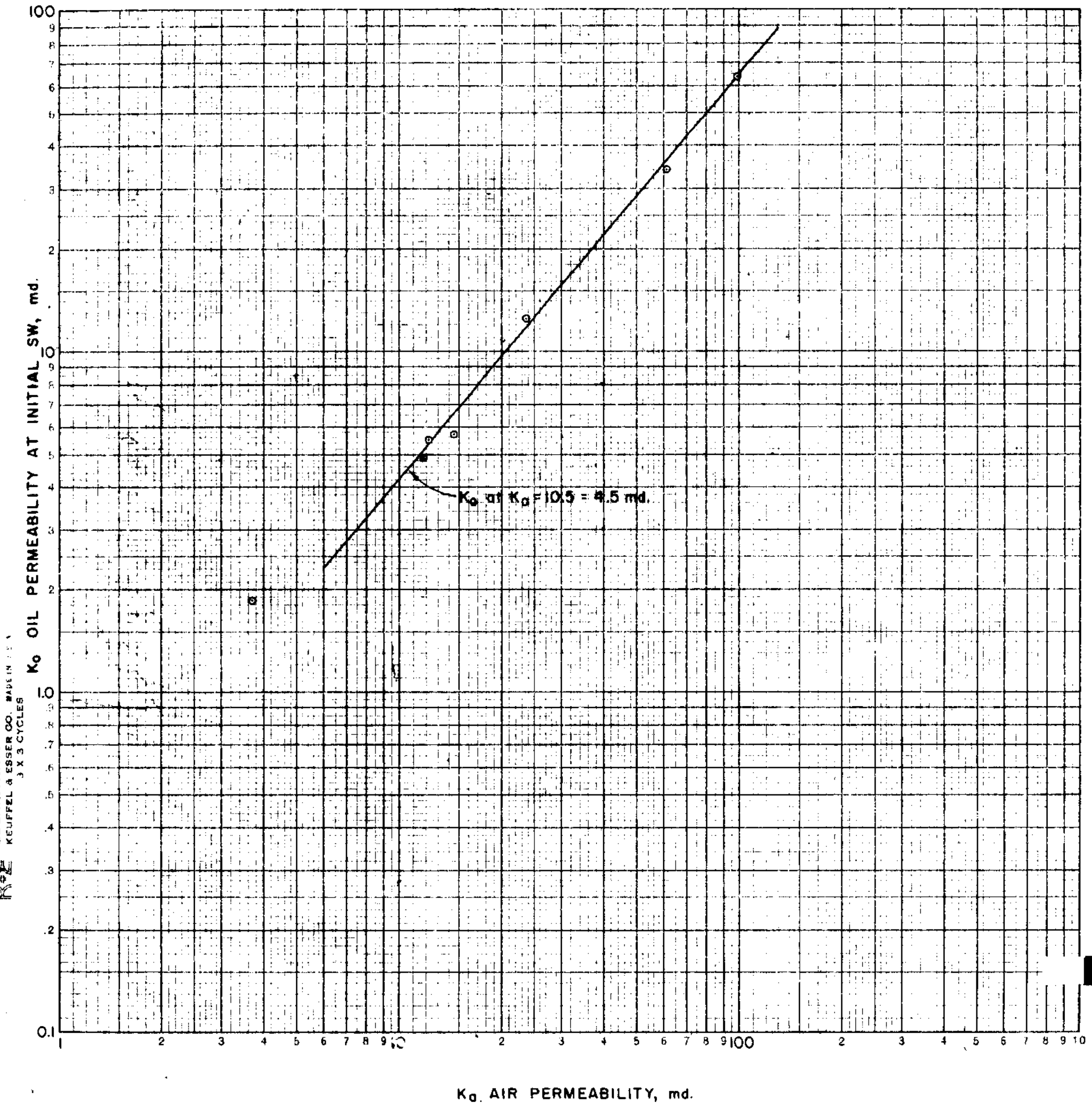


35 KEL 1 E58
10 X 10 to the ½ inch, 5th lines accented.
MADE IN U.S.A.

FIGURE 35

NORTH VIRDEN SCALLION

OIL PERMEABILITY vs. AIR PERMEABILITY



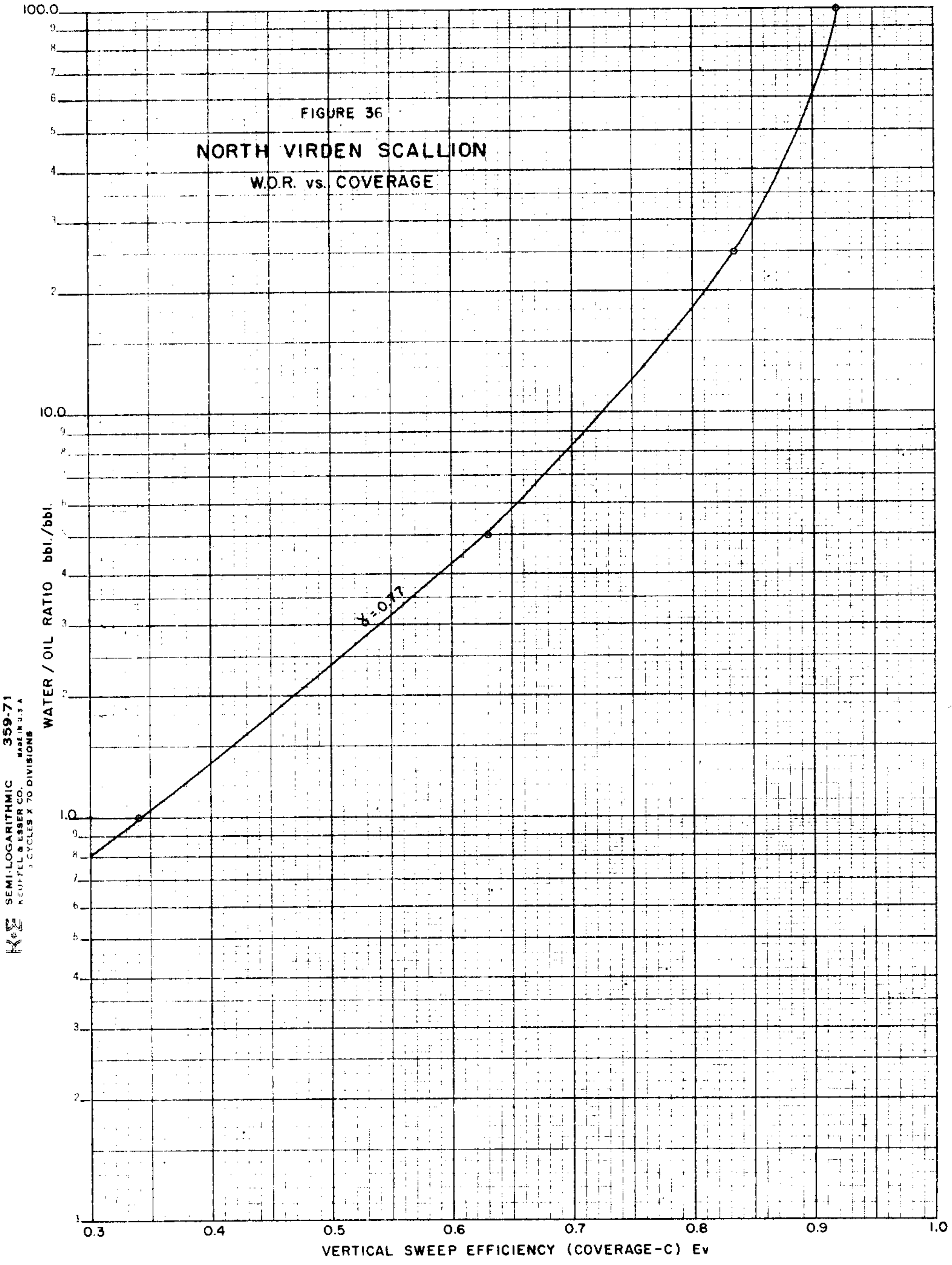


FIGURE 36
NORTH VIRDEN SCALLION
W.O.R. vs. COVERAGE
WATER / OIL RATIO bbl./bbl.
VERTICAL SWEEP EFFICIENCY (COVERAGE-C) Ev
γ=0.77
100.0
10.0
1.0
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
SEMI-LOGARITHMIC 359-71
KEUFFEL & ESSER CO. MADE IN U.S.A.
3 CYCLES X 70 DIVISIONS

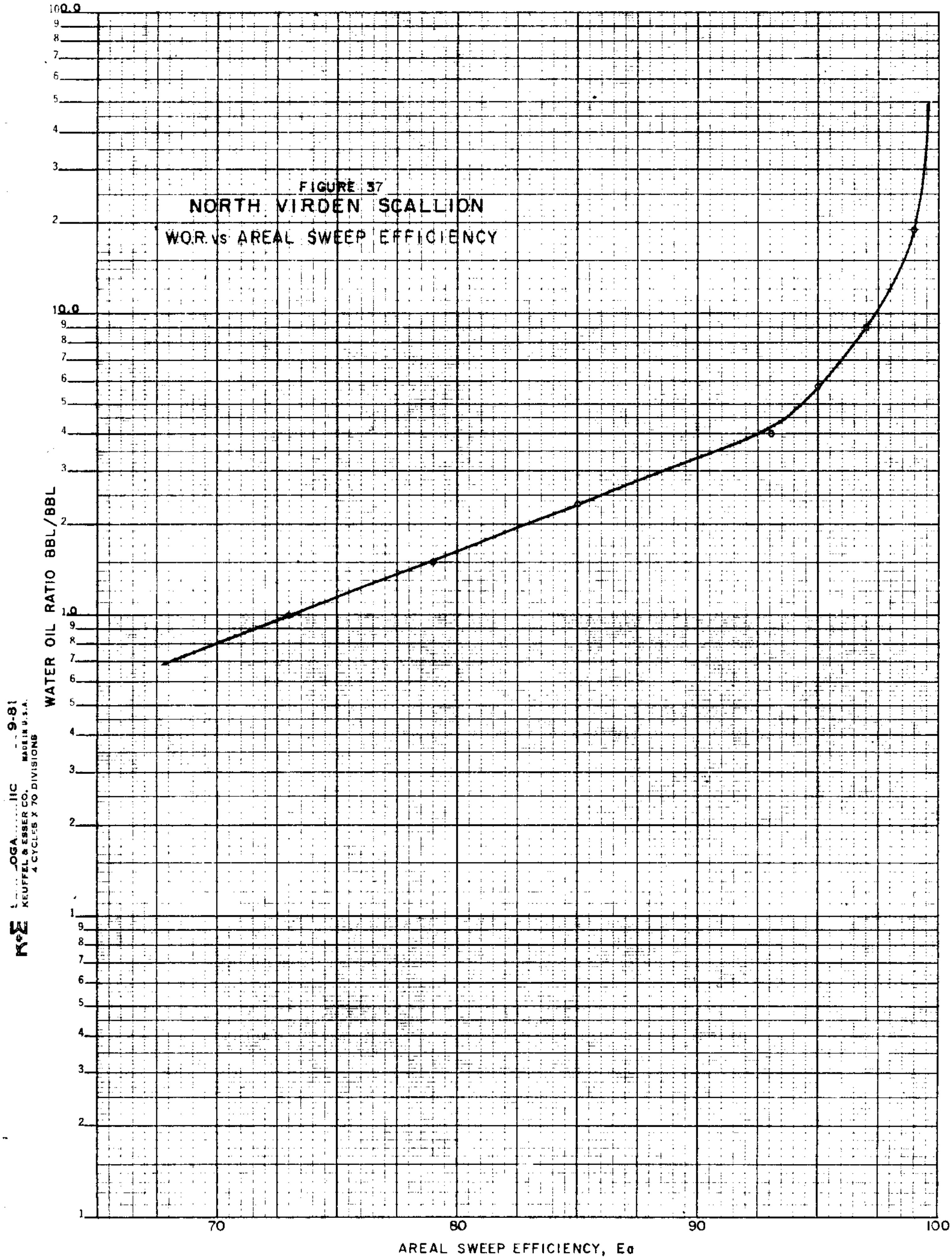


FIGURE 37
NORTH VIRDEN SCALLION
W.O.R. vs AREAL SWEEP EFFICIENCY
WATER OIL RATIO BBL/BBL
AREAL SWEEP EFFICIENCY, Ea
70
80
90
100
100.0
10.0
1.0
KEUFFEL & ESSER CO.
4 CYCLES X 70 DIVISIONS
MADE IN U.S.A.

[redacted]

TABLE I

NORTH VIRDEN SCALLION FIELD

Date of Bottom Hole Pressure Survey Results

Well Locations	April 1955	Sept. 1955	Dec. 1955	Feb. 1956	May 1956	Sept. 1956	Dec. 1956	July 1957	Sept. 1957	Jan. 1958	May 1961
LSD. 15-15-11-26	-	-	-	-	-	715	-	-	-	-	-
LSD. 9-16-11-26	906	860	-	-	-	-	-	-	-	-	-
LSD. 10-16-11-26	-	-	833	-	824	-	-	-	-	-	-
LSD. 8-20-11-26	-	-	-	-	-	-	-	-	-	682	-
LSD. 3-21-11-26	-	838	-	789	760	764	-	-	-	-	-
LSD. 10-22-11-26	-	-	-	-	-	461	-	-	-	-	-
LSD. 11-22-11-26	-	-	703	-	526	422	-	-	-	-	-
LSD. 4-23-11-26	-	-	-	895	-	747	677	590	572	525	203
LSD. 12-27-11-26	-	-	-	671*	433*	553	-	-	-	-	-
LSD. 3-33-11-26	-	-	-	-	-	727	-	-	-	-	-
LSD. 4-9-12-26	-	-	-	-	-	-	-	853	844	834	-
LSD. 6-2-11-26	-	-	-	-	-	-	-	-	-	-	702
LSD. 3-10-11-26	-	-	-	-	-	-	-	-	-	-	111
LSD. 11-14-11-26	-	-	-	-	-	-	-	-	-	-	201
LSD. 3-17-11-26	-	-	-	-	-	-	-	-	-	-	815
LSD. 2-21-11-26	-	-	-	-	-	-	-	-	-	-	695
LSD. 2-34-11-26	-	-	-	-	-	-	-	-	-	-	256
LSD. 7-5-12-26	-	-	-	-	-	-	-	-	-	-	596

All values in table expressed as psig

* Incomplete build up

TABLE II

NORTH VIRDEN SCALLION FIELD

AVERAGING K_W/K_O vs S_W CURVE

CHERTY ZONE

	Water Saturation, S_W								
K_W/K_O	#43	#47	#57	#28	#48	#12	#52	Total S_W	Average S_W
100	57.0	60.3	62.0	64.0	65.4	66.5	68.6	443.8	63.4
90	56.8	60.2	61.9	63.8	65.3	66.3	68.5	442.8	63.3
80	56.7	60.1	61.8	63.5	65.2	66.2	68.4	441.9	63.1
70	56.5	60.0	61.5	63.2	65.1	66.1	68.3	440.7	63.0
60	56.2	59.9	61.2	63.0	65.0	66.0	68.2	439.5	62.8
50	56.0	59.7	61.0	62.7	64.9	65.8	68.1	438.2	62.6
40	55.8	59.3	60.8	62.1	64.8	65.5	68.0	436.3	62.3
30	55.2	59.0	60.2	61.7	64.3	65.0	67.9	433.3	61.9
20	54.5	58.0	59.3	60.5	63.9	64.3	67.5	428.0	61.1
10	53.1	56.2	57.3	58.2	62.7	62.8	66.8	417.1	59.6
9	53.0	56.0	57.0	58.0	62.5	62.5	66.7	415.7	59.4
8	52.8	55.7	56.7	57.4	62.2	62.2	-	347.0	57.8
7	52.3	55.1	56.1	57.0	62.0	61.9	-	344.4	57.4
6	52.0	54.7	55.5	56.2	61.7	61.5	-	341.6	56.9
5	51.7	53.9	54.8	55.3	61.2	60.9	-	337.8	56.3
4	51.0	52.9	53.8	54.2	60.5	60.0	-	332.4	55.4
3	50.2	51.4	52.2	52.8	59.8	58.9	-	326.2	54.4
2	49.1	49.2	50.0	50.5	58.2	56.9	-	313.9	52.3
1	46.9	44.8	45.2	45.5	55.0	52.2	-	289.6	48.3
0.9	46.4	43.9	44.3	44.5	54.5	51.5	-	285.1	47.5
0.8	46.0	42.9	43.5	43.5	54.0	50.4	-	280.3	46.7
0.7	-	41.8	42.2	42.2	-	49.2	-	175.4	43.9
0.6	-	40.6	41.0	41.0	-	48.0	-	170.6	42.7
0.5	-	38.9	39.1	39.1	-	46.1	-	163.2	40.8
0.45	-	38.0	38.0	38.0	-	45.1	-	159.1	39.8
0.40	-	36.9	36.9	36.9	-	44.1	-	154.8	38.7
0.35	-	35.7	35.7	35.3	-	43.0	-	149.7	37.4
0.30	-	34.1	34.1	33.8	-	41.7	-	143.7	35.9
0.25	-	32.8	32.8	32.0	-	40.0	-	137.6	34.4
0.20	-	31.0	31.0	30.0	-	38.1	-	130.1	32.5
0.15	-	28.8	28.8	27.5	-	36.0	-	121.1	30.3
0.10	-	26.0	26.0	24.8	-	33.0	-	109.8	27.5

TABLE III

NORTH VIRDEN SCALLION FIELD

PREDICTION OF WATER FLOOD RECOVERY IN WELGE'S METHOD

(1) S_w	(2) K_w/K_o	(3) $\frac{\mu_o}{\mu_w}\frac{K_w}{K_o}$	(4) $f_o = \frac{1}{1+\frac{\mu_o}{\mu_w}\frac{K_w}{K_o}}$	(5) $1/Q_i = \frac{df_w}{dS_w}$	(6) $S_{av} - S_w = Q_i f_o$	(7) S_{av}	(8) $S_{or} = 1 - S_{av}$	(9) $E_d = \frac{S_{oi}-S_{or}}{S_{oi}}$	(10) Res. WOR $= \frac{1 - f_o}{f_o}$
0.29	0.079	0.364	0.733	3.60	0.204	0.494	0.506	0.287	0.36
0.30	0.094	0.433	0.698	3.50	0.200	0.500	0.500	0.296	0.43
0.32	0.126	0.581	0.633	3.35	0.189	0.509	0.491	0.308	0.58
0.34	0.165	0.761	0.568	3.10	0.183	0.523	0.477	0.328	0.76
0.36	0.213	0.982	0.505	2.90	0.174	0.534	0.466	0.344	0.98
0.38	0.272	1.254	0.444	2.70	0.164	0.544	0.456	0.358	1.25
0.40	0.340	1.567	0.390	2.50	0.156	0.556	0.444	0.375	1.56
0.42	0.415	1.913	0.343	2.50	0.137	0.557	0.443	0.376	1.92
0.44	0.501	2.310	0.302	2.30	0.131	0.571	0.429	0.396	2.31
0.46	0.630	2.904	0.256	2.25	0.114	0.574	0.426	0.400	2.91
0.48	0.815	3.757	0.210	2.10	0.100	0.580	0.420	0.408	3.76
0.50	1.08	4.979	0.167	2.00	0.084	0.584	0.416	0.414	4.99
0.52	1.51	6.961	0.126	1.90	0.066	0.586	0.414	0.417	6.94
0.54	2.18	10.050	9.090	1.70	0.053	0.593	0.407	0.427	10.11
0.56	3.30	15.213	0.062	1.40	0.044	0.604	0.396	0.442	15.13
0.58	5.75	26.508	0.036	1.05	0.034	0.614	0.386	0.456	26.78
0.60	11.4	52.554	0.019	0.70	0.027	0.627	0.373	0.475	51.63
0.62	34.0	156.740	0.006	0.30	0.020	0.640	0.360	0.493	165.67

TABLE IV

NORTH VIRDEN SCALLION FIELD

COMBINING E_d, E_v AND E_a TO PREDICT FLOOD BEHAVIOR

Reservoir WOR	E_d	E_v	E_a	Recovery R	Stock Tank WOR (β x WOR)	Stock Tank Oil Cut (1/1 + WOR)
0.88	0.352	0.319	0.713	0.080	0.92	0.521
0.90	0.352	0.322	0.716	0.081	0.95	0.513
1.0	0.356	0.340	0.730	0.088	1.05	0.488
1.5	0.369	0.418	0.788	0.122	1.58	0.388
1.7	0.373	0.440	0.807	0.132	1.79	0.358
1.85	0.377	0.455	0.818	0.140	1.94	0.340
2.0	0.378	0.470	0.829	0.147	2.10	0.323
2.5	0.386	0.510	0.861	0.169	2.63	0.275
3.0	0.392	0.540	0.886	0.188	3.15	0.241
4.0	0.402	0.590	0.925	0.219	4.20	0.192
5.0	0.409	0.628	0.943	0.242	5.25	0.160
5.1	0.410	0.630	0.944	0.244	5.40	0.150
6.0	0.415	0.654	0.952	0.258	6.30	0.137
7.0	0.421	0.676	0.960	0.273	7.35	0.120
8.0	0.425	0.695	0.966	0.285	8.40	0.106
9.0	0.429	0.710	0.970	0.295	9.45	0.096
10.0	0.432	0.724	0.974	0.305	10.50	0.087
15.0	0.446	0.778	0.986	0.342	15.75	0.060
20.0	0.456	0.805	0.991	0.364	21.00	0.045