

RESERVOIR STUDY

NORTH VIRDEN SCALLION FIELD, MANITOBA

The California Standard Company  
Engineering Division  
May, 1958

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RESERVOIR STUDY  
NORTH VIRDEN SCALLION FIELD, MANITOBA

May, 1958

SUMMARY

I. Statement of Problem

To analyze the primary performance, and to investigate the possibility of secondary recovery of oil from the Mississippian limestone in the North Virden Scallion Field, Manitoba.

II. Findings

- See P. 7*
- A. The discovery of oil saturation and commercial production in the Lodgepole formation of the Mississippian at California Standard Scallion 3-11 during December, 1953, led to the development of the North Virden Scallion Field (formerly North Virden field) in Manitoba.
  - B. The original oil was an undersaturated 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 oil in place from volumetric calculations is 163,000,000 barrels for the entire field.
  - D. Primary performance from decline curve analysis indicates a recovery of 20,000,000 barrels. This indicated recovery is 12% of the oil in place. Cumulative production to February 28, 1958 is 5,974,038 barrels, or 3.7% of the estimated oil in place. 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 15 psi. per month decline at Sun 4-23. This pressure drop is reflected in the average well production decline of 11 BOPD per year.
  - F. Water Flood calculations indicate a total ultimate primary and secondary recovery of 35,900,000 barrels for the field, or 22% of the oil in place.
  - G. A field-wide water flood would necessitate building a pipeline to the Assiniboine River. This would cover a distance of approximately 4 1/2 miles and would cost an estimated \$124,000. Pilot flooding could be served by produced salt water.
  - H. Unitization or cross-line flooding agreements would require negotiations involving twelve operators.
- Table I*

- See fig 19 for cutoff*
- I. The estimated capital costs of a field-wide flood are 1.5 million dollars. This assumes development on an 80-acre 5-spot pattern.
  - J. A double five-spot pilot water flood located as shown in Figure 19 would recover an additional 1,340,000 barrels over primary performance.

### III. Conclusions

- 1. Ultimate recovery in the North Virden Scallion field can be substantially increased by water flooding.
- 2. A double 80-acre 5-spot pilot flood should be initiated as soon as possible in order to:
  - a) Acquire accurate injectivity data.
  - ?* b) Arrest pressure decline and increase production in the vicinity of the pilot flood.
- 3. Negotiations for unitization and/or co-operative flooding agreements should be initiated as soon as possible.

RESERVOIR STUDY  
NORTH VIRDEN SCALLION FIELD - MANITOBA

HISTORY

The discovery well, California Standard Scallion Prov. 3-11, located 3 miles north of the town of Virden, in LSD 3, Section 11, Township 11, Range 26, W.P.M. was spudded 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 five Oolitic zones. Casing was set at the top of the First Oolite. The open hole was acidized with 500 gallons. Flowing and swabbing yielded 143 bbls. at a final rate of 6 bbls/hr. The hole was re-acidized with 500 gallons and swabbing yielded 170 bbls. in 26 1/2 hours, cutting 0-6% water. A third acid job with 4,500 gallons gave 357 bbls. in 41 hours at a final rate of 5 bbls/hr. cutting 8-16% water. 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, cutting 7% by April, 1956, when a Crinoidal rework was attempted. This was thought to be unsuccessful. Production had decreased to 13 BOPD, cutting 37% by November, 1957.

Subsequent offset and stepout drilling by California Standard and other companies continued rapidly through 1955 when at year end 113 wells were producing. By September, 1957, there were 216 wells producing, including 100 California Standard wells. Peak field production was reached in July, 1957, at 6,846 BOPD of which 3,590 BOPD was produced from California Standard wells. Drilling is continuing presently at a much slower rate and is concerned with the extension of west and east flanks.

GEOLOGY

Note: 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. 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.

The North Virden Field lies on the northeast flank of the Williston Basin, directly north of the town of Virden. The field is basically a stratigraphic trap in the Mississippian, the limits partially controlled by a structural nosing.

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 glacial drift. The reservoir rocks are mainly clastic limestones, subdivided by thin interbeds of argillaceous limestone. The Lodgepole Formation has been subdivided into three members - the Scallion Member, the Virden Member and the Whitewater Lake Member in ascending order (see Figure 1). 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.

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 14) 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.

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 cyclo 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.

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

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

As mentioned before the field is partially controlled by structure. This is in the form of a true structural nose, reflected somewhat by the Lodgepole erosion surface (see Figure 2). 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 being somewhere near the oil/water contact in the Cherty Zone. An acid wash with mud acid and a squeeze with regular acid was used to stimulate the wells, which were then swabbed for a short evaluation. Bottom hole pump and rods were run in 2" tubing and the well placed on production. Some wells flowed initially.



Further stimulation was employed, particularly in the southern portion of the field. A section opposite the Grinoidal was perforated with jets and bullets and a small size (10,000# and less) sandfrac was used to stimulate this zone. The open hole below was temporarily plugged off. The sand carrying agent is viscous crude (local crude with additives) in this sand-oil process.

Recently, the trend has been toward casing through the entire pay section, setting the float collar 5' below the base of staining in the Cherty Zone. All wells are cored through most of the pay section and down to the base of oil staining. The zones which appear favorable on cores and logs are selectively perforated through the casing and are stimulated. Also a change of ideas on stimulation technique has taken place. It is thought that a sand-oil or sand-acid fracture treatment will more completely stimulate this type of reservoir and this then, is the method commonly used now. Where any evidence of open fracturing (mainly in the Oolites or Cherty Zone) is shown, the treatment is generally restricted to an acid job. The unfavorable feature of the fracturing treatment is that induced fractures tend to extend downward, and where sets of perforations are relatively close together, the primary cement job gives way establishing circulation between the perforations outside the casing. For this reason experimenting with pozmix, gel and latex cement, and with cementing procedure has been carried out.

#### 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.

One profile, that of California Standard 12-16 (LSD 12, Section 16, Township 11, Range 26, W.P.M.) which was cored through the entire basal carbonate to the top of the Bakken Formation, revealed a number of interesting items (see Figure 4). The Scallion Member here, as in other wells in the field which penetrated its total extent, attains a total of approximately 200 feet of vertical thickness. 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.

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

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.

The main portion of the reservoir, the Cherty Zone, seems to have enough permeability and vertical connection from lens to lens to be reasonably efficiently swept by any secondary recovery program. *fracturing*

### ISOPACHS

The largest single variable factor seems to be the "effective pay" thickness, and thence oil in place, so this feature was examined in as much detail as possible. It was decided to treat the reservoir as three separate zones for oil in place calculations. The best guide is the core analysis and approximately one well out of four has had the core analyzed.

A permeability out-off of 1.0 md. was selected for all zones. Isolated permeable stringers of low vertical extent were ignored. Other techniques of picking effective pay were considered, including log interpretation and core description. The finished isopachs, however, were based mainly on the core analysis results.

The Cherty Zone proved to have the most complete information except in the southernmost area. A questionable factor was the establishment of an oil-water contact. This contact is transitional in nature, and can be seen on some electrical logs (see Figure 5). Attempts at making up oil-water contact structure maps from D.S.T. results and from logs did not improve on the existing map. This map is based mainly on visual examination of cores and is shown in Figure 3 (California Standard Producing Department Map No. F-7985-B6). The top of the Cherty Zone is readily determinable from core and log picks. Where the core analysis did not extend to the oil-water interface a percentage of net pay to gross pay from the cores analyzed throughout the field was used to extrapolate. From these values, and with the aid of logs and core descriptions, an isopach was drawn (see Figure 6).

Using average porosity figures from the analyses available combined with pay thickness indicated on the isopach, a porosity-thickness map was produced. This gives the pore volume and is used later to calculate the oil in place (see Figure 7).

Much the same technique was used for the other zones. The Oolitic Zone had more complete information and the total section was analyzed in most cases. Thus it was not necessary to depend on extrapolation to such a large degree to permit drawing of isopachs and contours of porosity footage (see Figures 8, 9). The procedure for the Crinoidal was similar, although the complete section was not always analyzed (see Figures 10, 11).

*Handwritten notes:*  
1. Handwritten notes in left margin, possibly related to the Crinoidal zone or permeability.

*Handwritten notes:*  
Discussion of Figure 5, mentioning electrical logs and oil-water contact.

*Handwritten notes:*  
Also used logs 10 & 11 OR see p 8 & discuss well.

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 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; Grinoidal Zone, two samples, 3.2 to 16.1 md., average 9.6 md. The pertinent results of the tests are shown below:

	<u>Cherty Zone</u>	<u>Oolitic Zone</u>	<u>Grinoidal Zone</u>
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 12 (see Appendix II B). Also included in the report was a water permeability at flood end versus air permeability curve (shown in Figure 26).

B. Subsurface Fluid Analysis

Reservoir fluid studies have been carried out by Core Laboratories Inc. on three North Virden Scallion field wells, California Standard Scallion wells 3-21, 4-11 and 10-16. 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 other two tests were used and the results are as follows:

1. The average saturation pressure of the fluid at reservoir temperature was 145 psig. This indicates that the reservoir fluid exists in a highly undersaturated 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 fluid viscosities were 3.52 centipoises at saturation pressure, and 5.74 centipoises at atmospheric pressure.

*Has this information been submitted to Wines? Possible? California Cor. Reference in 10-16*

*See section on 10-16*

Well no. 10-21  
4-25 p.m. 11/57

BOTTOM HOLE PRESSURES

The bottom hole pressure on California Standard Soallion 9-16 was 906 psig. in April, 1955. This was the first accurate survey taken in the field. A survey in September, 1955, shows 859 psig. No further pressures have been obtained. The well which has been surveyed the most often, Sun E. Hutchinson 4-23, shows an average drop of 15 psi/month since it was drilled. This well has never produced any oil and is on the east flank of the field. At this rate, Soallion 9-16 would have decreased to 425 psig. by December, 1957. The long shut-in time required to obtain a complete build-up with its resulting loss in production is the biggest drawback to running bottom hole pressure surveys in this field. The poor control and questionable results make it impossible to state any definite trends. The pressures are higher on the western flank but are dropping moderately fast throughout the field. The results of all available surveys are shown in Table I.

Transfer of 11/1/57  
to other wells?

RESERVES AND PRIMARY PERFORMANCE

Original Oil in Place

An estimate of the original oil in place was made by the volumetric method and was calculated to be 163,000,000 barrels for the total field. Of this, 131,000,000 barrels are in the Cherty Zone, 18,000,000 barrels in the Oolites, and 14,000,000 barrels in the Grinoidal. The following field average values were used:

	<u>Cherty Zone</u>	<u>Oolitic Zone</u>	<u>Grinoidal Zone</u>
1. Footage weighted average porosity	12.9%	11.2%	10.7%
2. Effective pay thickness	22.1'	5.5'	9.5'
3. Initial oil saturation	59%	51%	48%
4. Formation volume factor	1.045 bbl/bbl.		

Total 1.224  
See 2.7. 48

In calculating this total oil in place, the Grinoidal only in the southern part of the field was considered. See details in Appendix I A. A map showing the completion zone for each well is shown in Figure 20.

Primary Performance and Decline Curve Analysis

A well-by-well analysis of decline curves and extrapolation of rate-cumulative curves gave primary recoveries ranging from 3% - 28% but averaging around 10%. The difficulty in predicting performance on an individual well basis is that many of the wells have not yet shown a definite trend in their rate-cumulative curve. Also it is difficult on an individual well basis to predict which of the zones are contributing to production. The wells near the flanks (especially on the western edge)

2029  
11/5/55  
11/5/57

Assum.

Assume would be calculated for shooting purposes see page 19  
Extrapolation of initial oil saturation used in calculation of formation volume factor  
1.045 bbl/bbl

may be showing higher percent recovery due to the edge-water expansion. Periodic production water out maps seem to substantiate this, (see Figure 13). The fracture system has been studied and is shown in Figure 14. Productivity is higher in this area as is evidenced by individual well decline curves.

The difficulties which become troublesome in individual well decline curve analysis seem to become less obvious and somewhat masked in a total field decline curve analysis. Here the ~~average rate per well~~ cumulative curve shows a trend as does the water out (see Figure 15). The latter is thought to be influenced by the edge wells which are producing large amounts of water and does not represent a typical well in the central portion of the field. Individually, these wells are starting to decline and are not showing high water cuts. A rate per well versus time curve has been shown in Figure 16. Using all these other curves as a guide the rate-time curve has been extrapolated to give the primary reserves. The primary reserves for the field have been estimated at 20,000,000 barrels. This is 12% of the original oil in place. *field*  
*central*  
*recoverable*

The cumulative field production to February 28, 1958 is 5,974,038 barrels, or 3.7% 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 I B). *11,541,137 3/12/60.*  
*7.7%*

#### METHODS OF SECONDARY RECOVERY AVAILABLE

In order to increase the recovery from 12%, it becomes necessary to analyze the methods of secondary recovery available.

There are a number of these methods -- water flooding, air or gas injection, and underground combustion. Water flooding has been selected as the most applicable in this field.

A pilot flood based on an 80-acre 5-spot pattern would conform with the 40-acre well spacing and could be expanded to include all the floodable area. Pattern flooding can be instituted in a field with or without unitization.

#### PREDICTION OF RECOVERY BY WATER FLOODING

The secondary recovery under water flooding was predicted using a combination of Welge's<sup>(1)</sup> displacement efficiency concept, Dykstra and Parsons<sup>(2)</sup> vertical sweep efficiency or permeability variation efficiency, and the concept of areal sweep efficiency in pattern floods as explained

by Caudle, Erickson and Slobod(3). The Stiles Method, an alternative solution to the Dykstra-Parsons Method, is not used here because it is applicable only where the mobility ratio is unity, a situation which is not the case here. A brief discussion of the ideas and limitations behind each method is presented here and detailed calculations are shown in Appendix II.

#### Welge Method

The Welge Method is basically a simplified 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(4) and by Buckley and Leverett(5). 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 method brings forth 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 too serious. The reservoir is considered to be a linear section in Welge's Method. The section is considered to have a length 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, funicular distribution (continuous) of both phases, effective permeabilities are functions of saturations only, and two fluids flowing.

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

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.

#### Dykstra and Parsons Method

This method of calculation of water flood recovery attempts to predict the vertical sweep efficiency considering permeability variations in the reservoir rock. It assumes statistical distribution of permeability throughout the section. That is, the logarithm of the permeabilities will show a linear relationship with the percentage on a probability scale.

It is assumed that there is no crossflow 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

Due to the configuration of flood patterns there will be portions of oil 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<sup>(3)</sup> 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

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

$$R = (\text{Displacement efficiency}) \times (\text{Coverage}) \times (\text{Areal sweep efficiency})$$

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 is done here, and detailed calculations are shown in Appendix II E, the end product being an oil out versus recovery curve for an 80-acre 5-spot pattern as hypothesized for the North Virden Scallion water flood.

The results of the flood calculations are shown on Figure 33. At water breakthrough 10% of the oil in place at beginning of flood has been recovered. Assuming water flooding commences October 1, 1959, the total ultimate oil recovery is estimated at 35,900,000 barrels. This is made up of 9,890,000 barrels estimated cumulative production to October 1, 1959 plus 26,010,000 barrels under flooding. A performance curve of a field wide flood is shown in Figure 17.

### POSSIBLE SOURCES OF INJECTION WATER

The most probable source of injection water for a field-wide flood would seem to be the Assiniboine River, approximately  $4\frac{1}{2}$  miles east of the North Virden Scallion field. This river is a geologically mature stream with a wide meander belt and moderate flood plain. A preliminary investigation of the river installation has been made in order to obtain cost estimates.

A 6" O.D. asbestos cement line could handle the transportation of water from the river banks to an injection plant. However, the 250' drop from river banks to the river would necessitate cement-lined steel. For greater detail see estimated costs on page 14.

Underground sources for injection water could include the produced water from the field itself. This would probably be suitable for a pilot flood but the amount (1,522 barrels per day in September, 1957) is not sufficient to handle the requirements of a field-wide flood estimated to be in the order of 10,000 barrels per day. A 6" line would handle up to 17,000 BPD.

A second underground source of water is the Ashville (or Viking) Sand which is known to be water bearing in many parts of the area and has flowed water to surface in the East Virden area of the Assiniboine River Valley in Sections 28 and 29, Township 10, Range 25, W.P.M.

A third underground source is in the glacial drift along the River in this same East Virden area. This gravel zone encountered at a depth of approximately 100' has flowed water in moderate amounts, but its extent and capacity is unknown. Compatibility with formation water would have to be considered with all these sources.

In all, the surface fresh water source in the Assiniboine River seems to be the most attractive; and it is the source assumed in the section on field-wide flooding.

### UNIT AND CROSS-LINE FLOODING AGREEMENTS

Expansion of the pilot flood could not be made without the co-operation of other operators. Field-wide flooding would require unitization or cross-line flooding agreements. The pilot flood would not prejudice future unitization or co-operative flooding.

### PILOT WATER FLOOD

A pilot water flood is proposed to test the feasibility of water flooding in North Virden Scallion. This proposed pilot water flood would be in the form of a double 80-acre five spot (see Figure 18). It would involve conversion of six producing wells to water injection and would



directly offset eleven producing wells. The location of the pilot flood has been chosen for several reasons, which are listed below:

- 150 9-15 ??
- a) The pay zone in this area represents reasonably average conditions, with a moderate section of Cherty Zone pay which is the main zone under consideration.
  - b) Wells with good initial production respond most rapidly to flooding. *Why?* Thus pilot flood results can be assessed in the shortest time.
  - c) The location is close to the present salt water disposal plant located in LSD 9, Section 16, Township 11, Range 26, W.P.M., and existing facilities could be utilized conveniently. The water requirements could be supplied by salt water from this plant. *What happens to scheme if other operators use their water disposal facilities?*
  - d) A double five-spot was chosen to give more conclusive results in the same period of time, and would cost very little more than a single five-spot flood.
  - e) All the proposed injection wells are open to the Cherty Zone, and only one is cased through; therefore a minimum of rework time and expense would be involved for conversion to injection.
  - f) The injectivity information obtained from the pilot flood may indicate the feasibility of a more efficient pattern for flooding the north part of the field (e.g. an axial line drive).

Flood predictions on the double five-spot pilot flood show the following:

- 1) Total recovery under flooding is 2,440,000 barrels.
- 2) Recovery factor is raised from 9.5% primary to 21% of the oil in place with water flooding.
- 3) The increase in reserves is 1,340,000 barrels. *? recoverable reserves?*

This assumes water flooding commences October 1, 1958.

The capital costs involved in such a pilot flood are estimated to be:

Additions to salt water disposal plant	\$32,000
Conversion of wells to injection	28,000
Injection lines	25,000
Indirect expense	7,000
Total	<u>\$92,000</u>

This considers using salt water disposal plant facilities wherever possible, including settling pits and pump. See Figure 19 for performance curve of the pilot flood.

### FULL SCALE WATER FLOODING

The pilot flood could be expanded to include most of the field, if desired. The nature of co-operative agreements between the various operators would determine the form of expansion.

As mentioned previously under "Sources of Injection Water", field-wide flooding would in all probability require building a pipeline from a central injection plant to the Assiniboine River, a distance of some 4 1/2 miles. Cement-lined steel would be required to negotiate the 250' drop from river banks to the river bed and a pump installed at the base. Water clarification facilities would probably be needed here if raw river water was used. 6" O.D. asbestos-cement line seems suitable for the majority of the line from river banks to injection plant. At the plant storage facilities, filters, backwash pumps, electrical controls and settling pits would be needed, as well as an injection pump. The injection system has been considered as a diagonal grid of 2" and 3" O.D. cement-lined steel pipe.

The flood calculations, as outlined previously, show the following results when applied to the total field under flooding:

- 1) Total ultimate recovery, primary and secondary is 35,900,000 barrels.
- 2) The recovery factor is raised from 12% primary to 22% with flooding.
- 3) The increase in reserves is 15,900,000 barrels.
- 4) The secondary recovery life is estimated at 18 years.

These predictions assume that unitization and/or cross-line flooding agreements have progressed to the stage wherein all wells designated for water injection under a five-spot pattern will be injecting by October 1, 1959. Also, the number of wells is assumed to remain constant at 230 (as of February 28, 1958). The decline is based on the present downward trend in the BOPD/well curve in Figure 16.

The estimated capital costs involved in this project are as follows:

Injection plants	\$170,000
Conversion of wells	480,000
Injection lines	450,000
Water supply	124,000
Field expense and contingencies	276,000
Total	<u>\$1,500,000</u>

These estimated costs assume a common water supply system, the costs of which would be prorated among the operators; regardless of the type of co-operative agreement reached.

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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:

$$N = 7,758 \phi A h S_{o_1} \frac{1}{\beta}$$

where

- N = stock tank oil in place, barrels
- $\phi$  = average footage weighted porosity, fractional
- A = surface area, acres
- h = effective pay thickness, feet
- $S_{o_1}$  = initial oil saturation, fractional
- $\beta$  = formation volume factor, bbl/bbl.

1) Porosity, Area and Thickness

The isopach maps previously mentioned were planimetered to give average pay thickness; and the porosity-feet maps planimetered to give average porosity feet. From these an average porosity can be found by dividing the average porosity-feet by the average pay thickness. The footage weighted porosity was also calculated averaging all the core analysis footage available in the different pay zones. The results are as follows:

<u>Zone</u>	<u>Average Pay Thickness</u>	<u>Average <math>\phi</math> from Map</u>	<u>Average <math>\phi</math> from Core Analysis</u>
Crinoidal *	9.47	10.67%	10.48%
Oolites	5.45	11.23%	11.39%
Cherty	22.10	12.92%	14.33%

\* Note: As mentioned previously the Crinoidal Zone is thought to be effective only in the southern portion of the field where it is open and this portion only is considered in these calculations (see Figures 10 and 11).

Comparing the average porosities found by the two different methods, it was decided that the figure derived from the porosity thickness map represented a better statistical average. It incorporates the total field rather than merely the wells which had the core analyzed and this figure was used in calculation in each case.

The term " $\phi A h$ " can thus be obtained from planimetering the porosity-thickness map for each zone. Following are the results along with the average individual factors found in this operation:

<u>Zone</u>	<u>Average Porosity fractional</u>	<u>Surface Area acres</u>	<u>Average Thickness feet</u>	<u><math>\phi A h</math> Porosity· Acre·feet</u>
Crinoidal	0.1067	3,490.5	9.47	3,525
Oolites	0.1123	7,723.6	5.45	4,710
Cherty	0.1292	10,448.0	22.10	29,833
Total			<u>37.02</u>	<u>38,068</u>

## 2) Oil Saturation

The average initial oil saturations ( $S_{o1}$ ) for each zone were calculated as follows:

### a) Cherty Zone

*only connate water used for whole area*

The basis of connate water determination (and thus oil saturation) was the analysis of the core from California Standard Scallion 9-23 (LSD 9, Section 23, Township 11, Range 26, W.P.M.). 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 logarithm 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 21).

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

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 logarithm 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.

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 22.

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 22 is 10.5 md and this corresponds to a water saturation of 0.41 or an initial oil saturation of 0.59 or 59%.

b) Oolitic Zone

The distribution plot of Oolite samples, constructed as described above is shown in Figure 23. The Oolite samples in the oil base core from 9-23 show little relationship between air permeability and water saturation. Most of the values fall between 40% and 60% water saturation and show no trend in the relationship (see Figure 24). It was assumed that saturation was not a function of permeability in the lenticular, permeable Oolite bands and an arithmetical averaging of the values gave a water saturation of 0.49 or 49%. Assuming this to be the best answer available the oil saturation is taken as 0.51 or 51% in the oil in place calculations. This was checked with South Virden results as for the Crinoidal.

c) Crinoidal

The Crinoidal zone was not well developed in California Standard Scallion 9-23 and therefore not cored and analyzed for water saturations. The Crinoidal has been cored in oil in the South Virden field, however, and it is thought to be

lithologically similar here a distance of some 8-9 miles away. Samples taken from oil base cores on California Standard South Virden 15-11 (LSD 15, Section 11, Township 10, Range 26, W.P.M.) and California Standard South Virden 12-1 (LSD 12, Section 1, Township 10, Range 26, W.P.M.) 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 21). The median air permeability of the Crinoidal is 3.0 md. as shown on the distribution plot, Figure 25. Using this median value and the Cherty Zone saturation plot the water saturation is 0.52, an oil saturation of 0.48 or 48%. This is thought to be a reasonable answer and is used in the calculations as shown later.

### 3) Formation Volume Factor

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

<u>Scallion Well No.</u>	<u>3 bbl/bbl.</u>
4-11	1.047
3-21	1.044
Average	1.045 bbl/bbl.

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

#### Cherty Zone

$$N = (7,758) (29,833) (0.59) \frac{1}{(1.045)}$$

$$N = 131,000,000 \text{ barrels/entire field}$$

or, using average figures

$$N = (7,758) (0.1292) (40) (0.59) \frac{1}{1.045}$$

$$= 22,600 \text{ bbl/ft/40 acre lease}$$

$$\text{or } N = (7,758) (0.1292) (0.59) \frac{1}{1.045}$$

$$= 566 \text{ bbl/acre.ft.}$$

Oolitic Zone

$$\begin{aligned}
 N &= (7,758) (4,710) (0.51) \frac{1}{(1.045)} \\
 &= 18,000,000 \text{ barrels/entire field} \\
 \text{or } N &= (7,758) (0.1123) (40) (0.51) \frac{1}{1.045} \\
 &= 17,000 \text{ bbl/ft/40 acre lease} \\
 \text{or } N &= 425 \text{ bbl/acre.ft.}
 \end{aligned}$$

Grinoidal Zone

$$\begin{aligned}
 N &= (7,758) (3,525) (0.48) \frac{1}{(1.045)} \\
 &= 12,800,000 \text{ bbl/entire field} \\
 \text{or } N &= (7,758) (0.1067) (40) (0.48) \frac{1}{1.045} \\
 &= 15,200 \text{ bbl/ft/40 acre lease} \\
 \text{or } N &= 380 \text{ bbl/acre.ft.}
 \end{aligned}$$

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

	<u>Oil in Place</u>	<u>Percent of Total</u>
Cherty Zone	131,000,000	<del>86%</del>
Oolites	18,000,000	<del>11%</del>
Grinoidal	12,800,000 14,000,000	<del>9%</del>
Total	163,000,000 161,500,000	<del>100%</del>

B. Primary Performance

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

$$\text{RF} = \frac{20,000,000}{163,000,000} = 12.3\%$$



or, on an average well basis (completed in all zones)

$$\begin{aligned}\Delta N &= 0.123 \left[ (22,600) (22.10) + (17,000) (5.45) + (15,200) (9.47) \right] \\ &= (0.123) (736,000) = 91,000 \text{ barrels.}\end{aligned}$$

These figures are from the above oil in place calculations and refer to a well draining all zones, and with average thicknesses. The Cherty Zone on an average would contribute 61,000 barrels of this or 67%.

The recovery due to oil expansion during a pressure drop from 900 psi (considered original) to 145 psi (saturation pressure) is:

$$\frac{\Delta N}{N} = \frac{\beta_s - \beta_i}{\beta_i}$$

where  $\beta_s$  = formation volume factor at saturation pressure.  
 $\beta_i$  = original formation volume factor.

$$\text{or } \frac{\Delta N}{N} = \frac{1.051 - 1.045}{1.045} = 0.6\%$$

APPENDIX II

INJECTIVITY AND FLOOD PREDICTION

A. Injectivity Calculations

The water injectivity rates were calculated from the formula:

$$Q = \frac{1.54 (k_w) (h) (\Delta P)}{\mu_w (\log_{10} \frac{d}{r_w} - 0.269)}$$

where Q = injection rate, bbl/day.

$k_w$  = reservoir permeability to water, darcies *spells*

h = vertical section, feet

$\Delta P$  = pressure differential ( $P_{\text{surface}} + P_{\text{wellbore}} - P_{\text{reservoir}}$ )

$\mu_w$  = viscosity of injection water at reservoir conditions, centipoises

d = distance from injection well to producing well in pattern flood, feet

$r_w$  = effective well bore radius, feet

This is derived from Darcy's flow formula, applied to a five-spot flood. The formula is applied to an average North Virden Scallion well assuming the following:

$$P_{wb} = 0.433 \text{ psi/ft} \times 2,100 \text{ ft.} = 900 \text{ psi.}$$

$$P_{inj} = 1,100 \text{ psi. (not to exceed overburden pressure).}$$

$$P_{res} = 500 \text{ psi. (average over flood life).}$$

$$\Delta P = 1,100 + 900 - 500 = 1,500 \text{ psi.}$$

$$\mu_w = 0.864 \text{ cp. at reservoir temperature}$$

$$d = 1,320 \text{ feet for an 80-acre 5 spot.}$$

$$r_w = 25 \text{ feet (radius of fracturing assumed)}$$

Therefore,

$$Q = \frac{1.54 (k_w) (h) (1,500)}{(0.864) (\log_{10} \frac{1,320}{25} - 0.269)}$$

$$Q = \frac{1.54 \text{ BHPD/md.} \times \text{ft.}}{(0.864) (\log_{10} \frac{1,320}{25} - 0.269)}$$

$$Q = 1.84 \text{ BHPD/md.} \times \text{ft.}$$

Applying this to average permeabilities and pay sections:

Cherty Zone

$$Q = 1.84 k_w h$$

$$Q = (1.84) (2.55) (22.1)$$

$$= 105 \text{ BHPD}$$

(Average  $K_{air} = 23.4 \text{ md.}$ , see Figure 26)

Oolitic Zone

$$Q = (1.84) (27) (5.5)$$

$$= 275 \text{ BWPD}$$

Crinoidal Zone

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

$$= 5 \text{ BWPD} \quad (\text{Total} = 385 \text{ BWPD})$$

This figure merely represents the order of magnitude of the stabilized rate, since all three zones are variable both in thickness and in permeability. It may be noted that in the pilot flood area the Cherty Zone permeability is better than the field average and thus injectivity could be of the order of 200-300 BWPD. In addition the Oolites, where present, will not have the same effect since the permeability is lower than average. Thus the Oolitic Zone injectivity could be of the order of 50-75 BWPD in the pilot flood area.

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: -

$$f_o = \frac{h}{c+h} + \frac{K (\Delta D) g \sin \theta}{\mu_o V_o} \frac{k_o}{c+h} \quad (1)$$

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
- $k_o$  = relative permeability to oil
- $K$  = total permeability to oil with connate water in place

- $\Delta D$  = water density less oil density
- $g$  = gravitational constant
- $\theta$  = average angle of stratum dip
- $\mu_o$  = reservoir oil viscosity
- $V_o$  = velocity of oil and water stream after leaving outlet sand face.

This neglects capillary pressure gradient, the term usually being negligible.

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 12). Because some of the  $k_w/k_o$  curves do not extend to the lower value of  $k_w/k_o$  used a slight periodic displacement may be noticed in the average  $k_w/k_o$  curve. This has been compensated for as may be noticed. 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 in column (2).

2. The term  $\frac{K (\Delta D) g \sin \theta}{\mu_o V_o} \frac{k_o}{c + h}$  which brings in the effect of gravity is usually negligible and the relationship of equation (1) is simplified to:

$$f_o = \frac{h}{c + h}$$

or substituting

$$f_o = \frac{1}{1 + \frac{\mu_o k_w}{\mu_w k_o}} \quad (2)$$

The value of  $\frac{\mu_o}{\mu_w}$  is calculated to be

$$\frac{\mu_o}{\mu_w} = \frac{3.98}{0.864} = 4.61$$

*assumed pressure*

Where  $\mu_o$  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  $\frac{\mu_o k_w}{\mu_w k_o}$  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 as seen in Figure 27. The lower extent of the curve is taken to be where  $S_w = 0.41$  the initial water saturation of the Cherty Zone.
5. From the relationship

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

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

Since  $f_w = 1 - f_o$  the  $f_w$  scale can be substituted for  $f_o$  only in reverse order. (see Figure 27).

Then for each value of  $S_w$ ,  $\frac{1}{Q_i} = \frac{df_w}{dS_w}$ , 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 then 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

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

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 28.

### 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  $V$ .

From graphs prepared by Dykstra and Parsons<sup>(2)</sup> and shown in Figures 29a, 29b, 29c and 29d, the coverage  $C$  (or  $E_v$ ) can be found for the various water/oil ratios knowing the permeability variation  $V$  and the mobility ratio  $\gamma$ .

From Figure 22 the permeability variation in the Cherty Zone is shown to be:

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

The mobility ratio  $\gamma$  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  
 $\mu_w$  = viscosity of injected water, at reservoir conditions  
 $\mu_o$  = 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 30). 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 C.R.C. report, the water permeability is 0.75 md. at 10.5 md. air permeability (see Figure 26).

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

$$\begin{aligned}\mu_o &= 3.98 \text{ cp. at } 80^\circ \text{ F and } 600 \text{ psi.} \\ \mu_w &= 0.864 \text{ cp. at } 80^\circ \text{ F and } 600 \text{ psi.}\end{aligned}$$

Therefore, the mobility ratio,  $\gamma$ , is calculated as follows:

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

From the graphs the following results are obtained:

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

These results are shown in graph form in Figure 31.

#### 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 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  $\gamma$ , 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 5-spot pattern, with  $M = 1.30$ :

<u><math>\Psi_s</math> (water cut)</u>	<u>WOR (bbl/bbl.)</u>	<u><math>E_a</math> (areal sweep eff.)</u>
0	0	0.73
0.5	1.0	0.85
0.6	1.5	0.87
0.7	2.33	0.91
0.8	4.0	0.94
0.85	5.67	0.97
0.9	9.0	0.99

These figures are shown in graph form in Figure 32 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 are 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 27). However, in this case the curve has a changing slope at all saturations above the original  $S_w$  (0.41) 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  $\sqrt{2} \times \text{WOR}_{\text{Res.}}$  in column (2) of this Table. The recovery  $R$  is  $E_d \times E_v \times E_a$ , the product of the three fractional recoveries. The stock tank oil cut is found from the producing WOR and thus becomes

$$\text{S.T. Oil Cut} = \frac{1}{1 + \sqrt{2} \text{WOR}_{\text{Res.}}}$$

A graph of percent recovery  $R$  versus stock tank oil cut is shown in Figure 33. A recovery of 10% is indicated to breakthrough, at which point the oil cut drops to 36%.



This prediction is applied to the oil in place as follows:

- 1) A curve of production rate versus time is drawn for the primary performance.
- 2) At the point of commencement of water injection the rate is assumed to drop by an amount equivalent to the production rate of the wells converted to injection.
- 3) After this the rate steadily increases to an assumed maximum rate and continues at this rate until water breakthrough. This point is where the cumulative flood production reaches an amount equal to the predicted recovery to breakthrough as explained above. The fractional predicted recoveries are applied against the oil remaining in place at the start of flooding.
- 4) Production rates after water breakthrough are calculated from oil cuts at certain recovery factors, using an assumed maximum rate of fluid production. These rates are correlated with time as shown in Table V.

Assuming water flooding October 1, 1959, the remaining oil in place is estimated at 153,110,000 barrels. The recovery to breakthrough is 15,310,000 barrels or 10% of this oil in place. In Table V the oil out (column (1)) is 100% up to breakthrough. At this point the oil out drops to 0.357 (Figure 33). The oil rate is equal to the oil out times the assumed maximum fluid rate (10,200 BPD). At various oil cuts after this the performance is calculated.

The recovery,  $R$ , comes from Figure 33 and is shown in column (2). The average oil rate, column (4), is the arithmetic average of oil production over the period. The cumulative production, column (5), is the recovery, column (2), times the oil in place at the start of flooding,  $N^1$ . Column (6) is the increment of production over this period. The increment of time in days, column (7), is column (6) divided by the average production rate over the period. The cumulative time is shown in column (8) in days, and in column (9) in years.

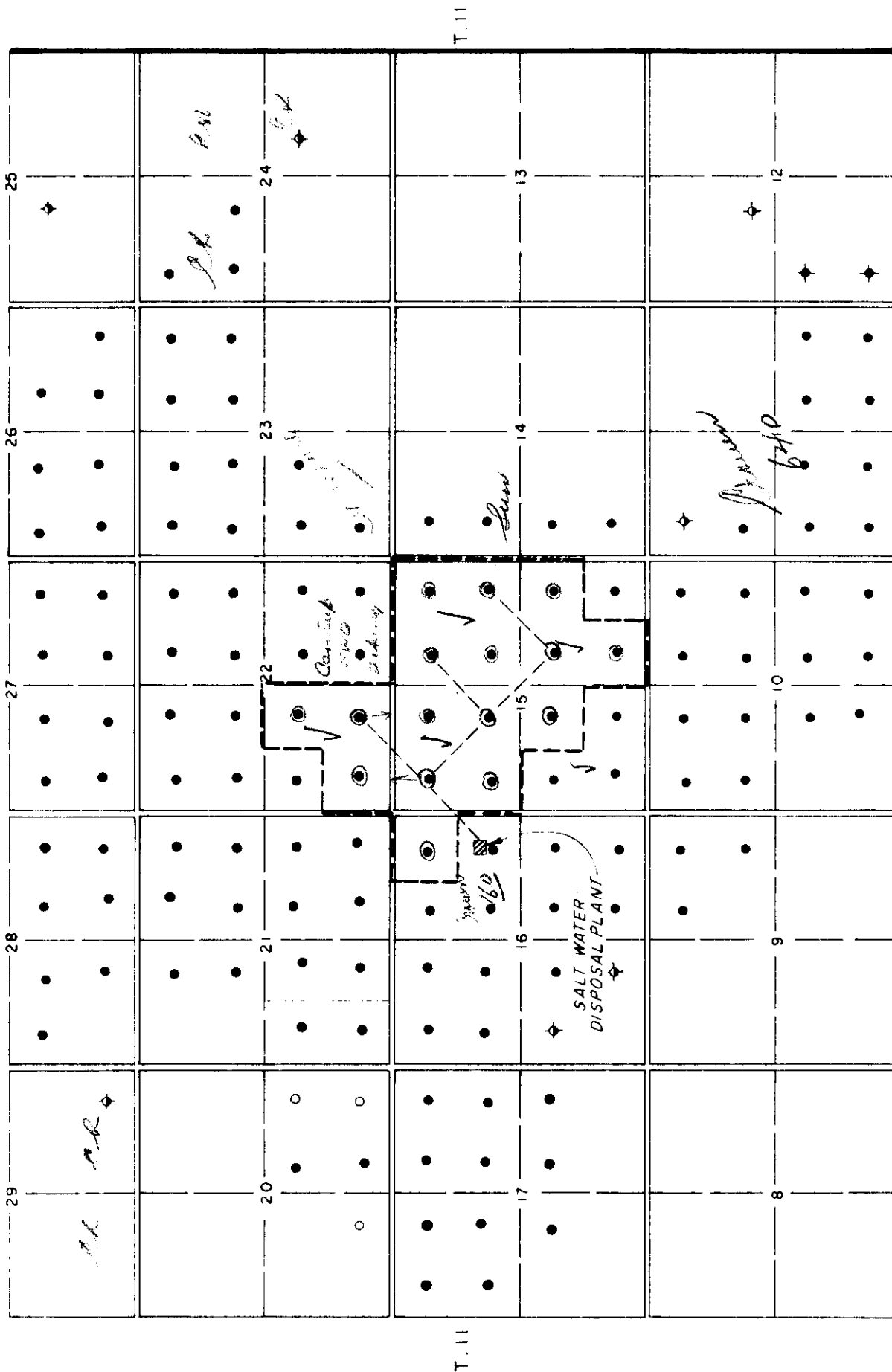
At breakthrough the curve is rounded off to conform with what happens in actual practice. Areas are balanced to give the same numerical result as if the curve dropped sharply off at breakthrough. See Figure 17.

FIGURE 1

**NORTH VIRDEN SCALLION**  
**STRATIGRAPHIC SECTION OF PRODUCING ZONES**

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

R. 26 WPM



# NORTH VIRDEN FIELD

PILOT WATER FLOOD

1958 PROGRAM

FIGURE 18

## LEGEND

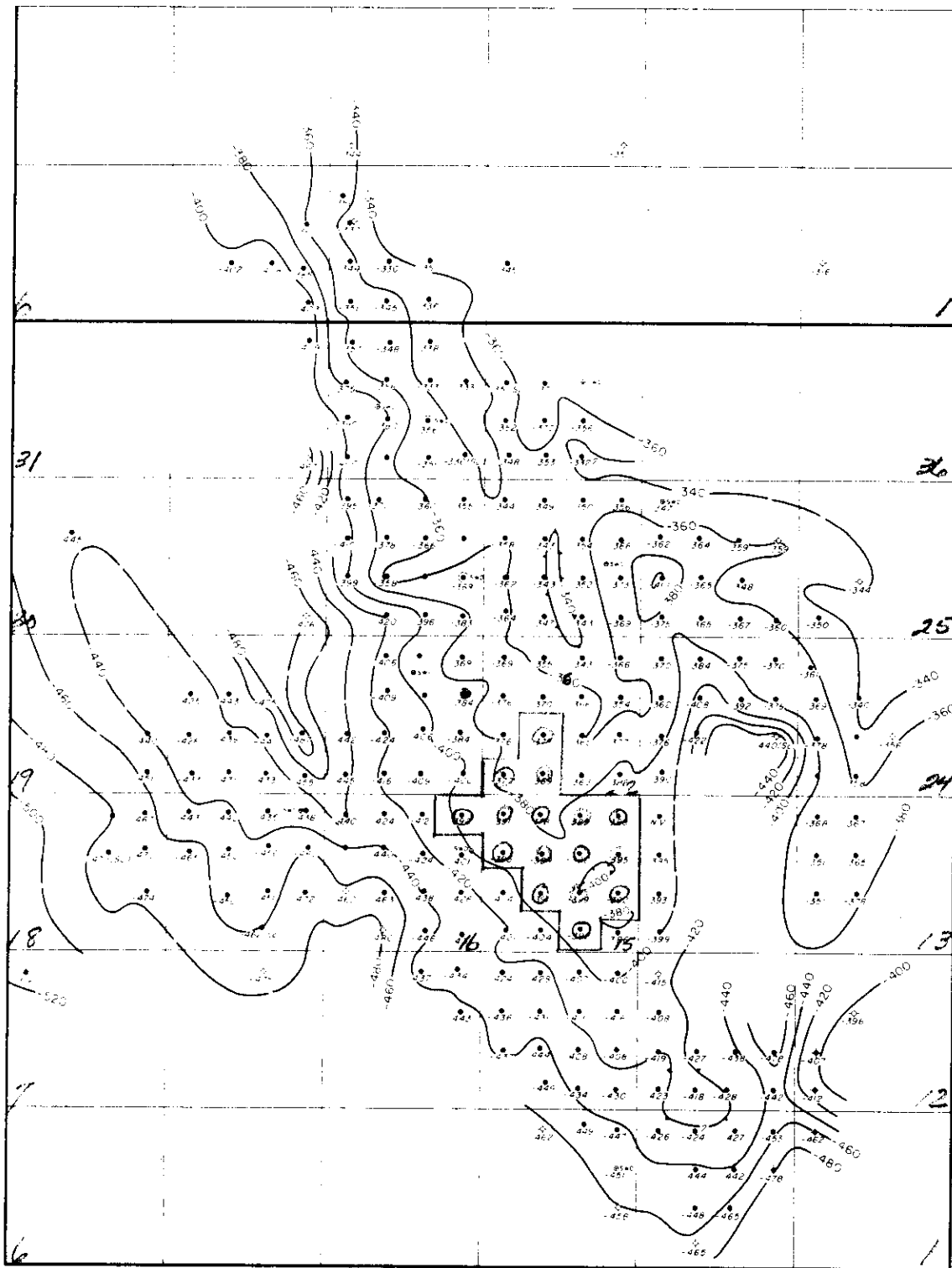
--- PROPOSED INJECTION LINES

• PROPOSED INJECTION WELL

--- WATER FLOOD EFFECTIVE AREA

R.26 W.P.M.

T.12



T.11

FIGURE 2  
NORTH VIRDEN SCALLION FIELD  
STRUCTURE CONTOURS  
ON TOP OF  
MISSISSIPPIAN

R.26 W.P.M.

T.12

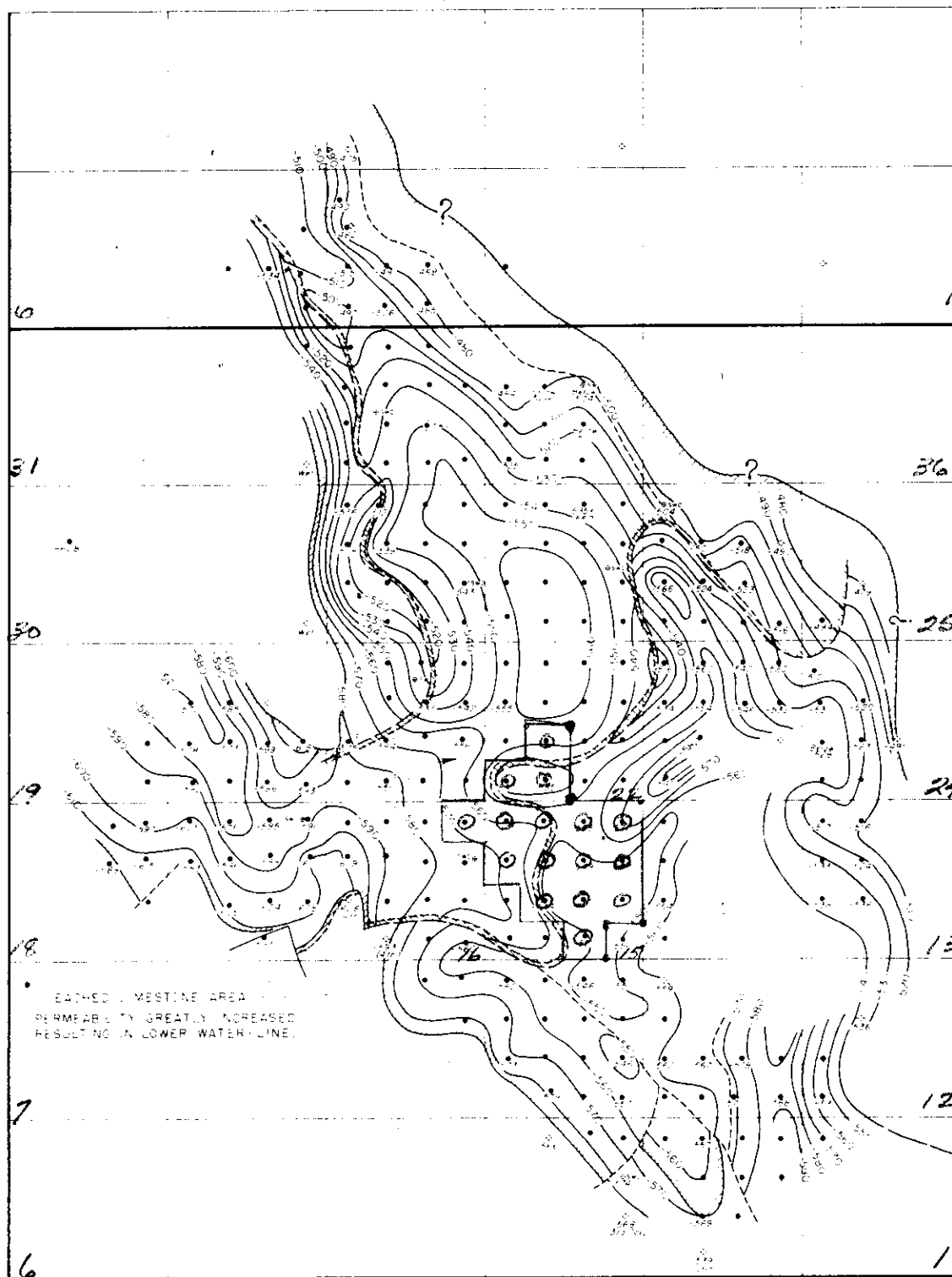


FIGURE 3

# NORTH VIRDEN SCALLION FIELD CHERTY ZONE CONTOURS ON OIL-WATER INTERFACE

0 10 FT

BY C. A. BERG

SCALE IN MILES

## -LEGEND-

- WATER-LINE DOES NOT FOLLOW STRUCTURE WITH HACHURES
- - - STRATIGRAPHIC JUMP IN WATER-LINE DUE TO PERMEABILITY CHANGES
- EDGE-WATER LINE

AUG 25, 1956

B-7590-10

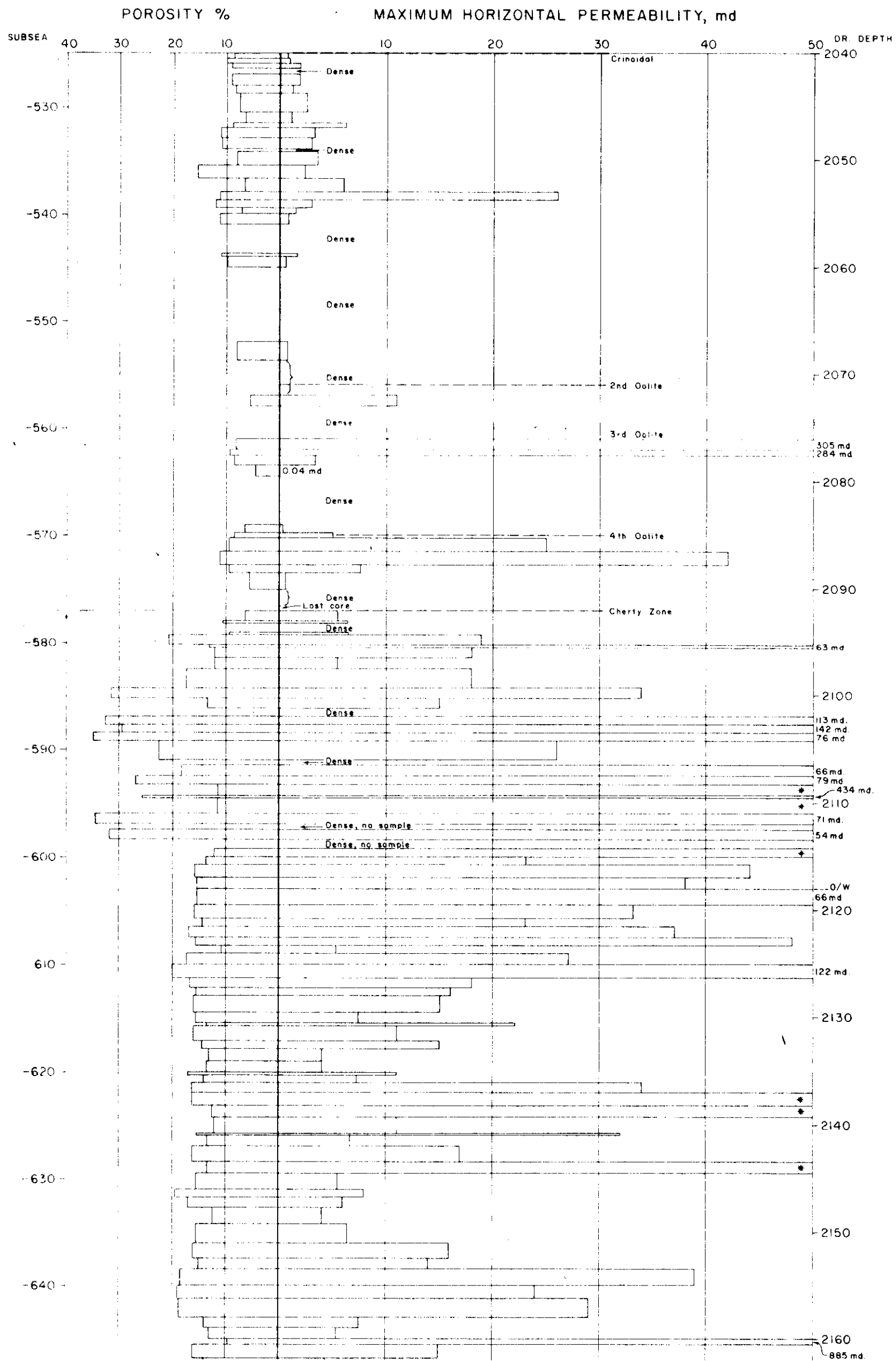
FIGURE 4

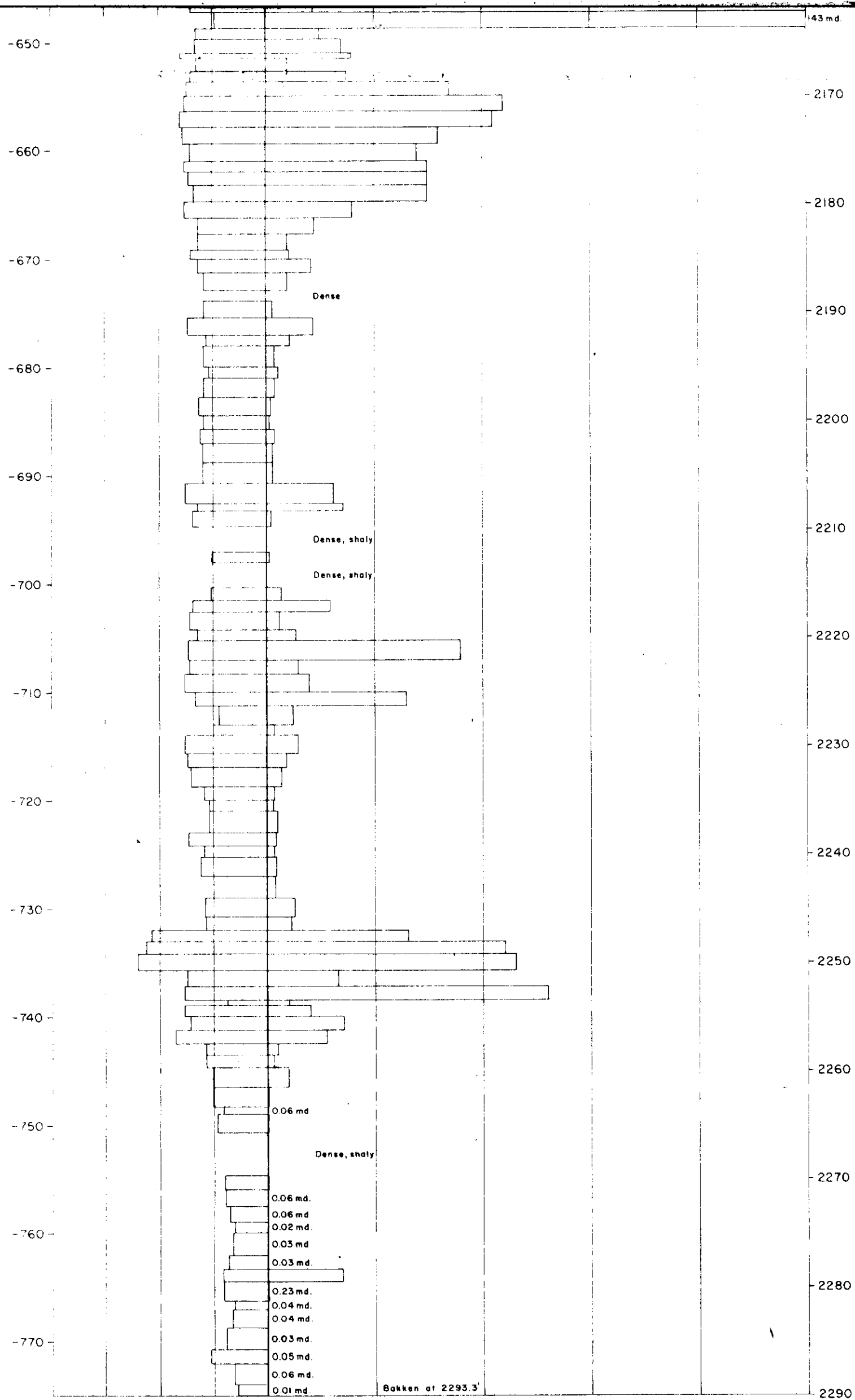
POROSITY AND PERMEABILITY PROFILE

CALIFORNIA STANDARD SCALLION 12-16

LSD. 12, SEC. 16, TWP. 11, RGE. 26 WPM

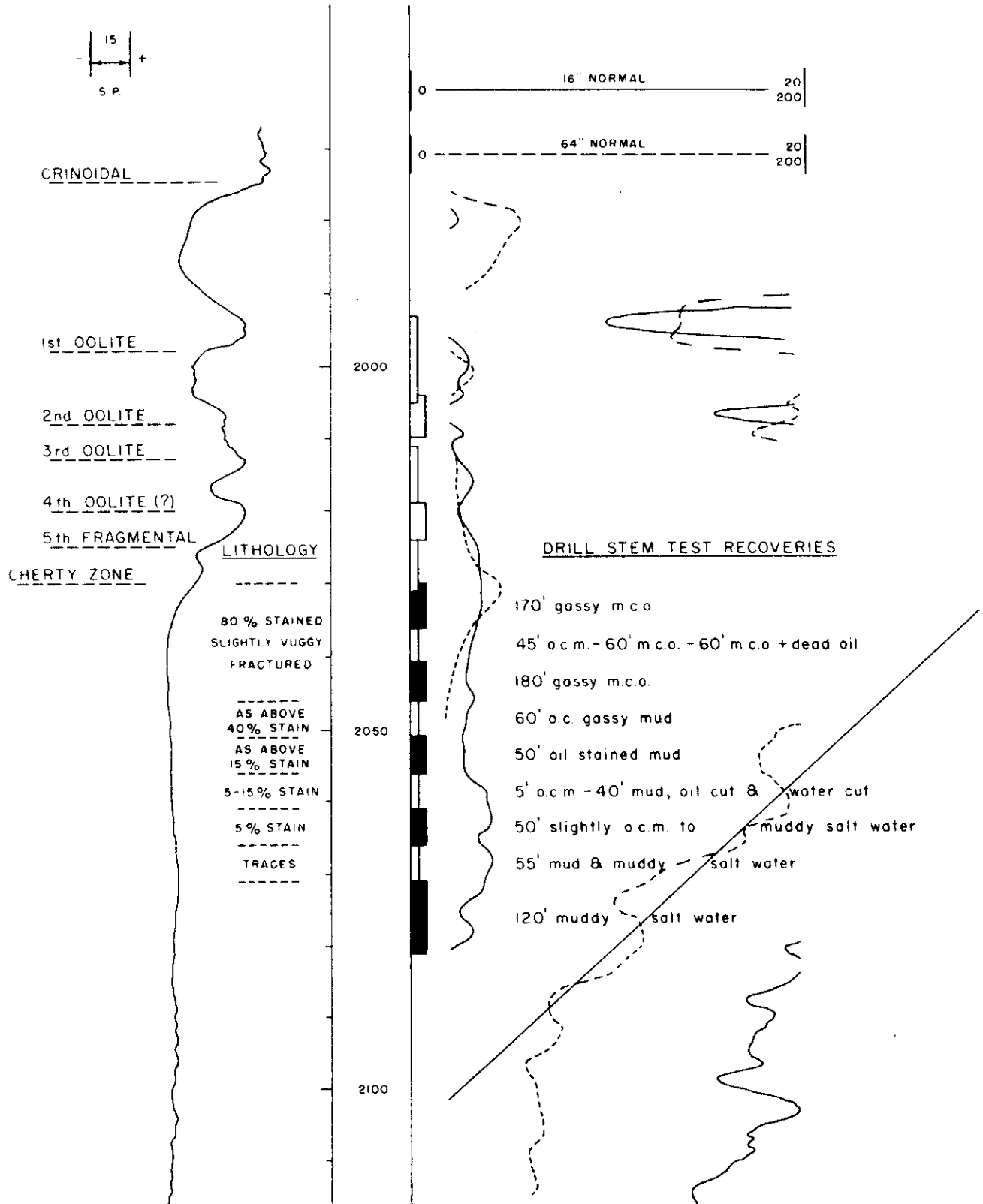
K.B., 1515'





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

FIGURE 5  
ELECTRIC LOG  
CALIFORNIA STANDARD SCALLION 5-II (5-II-II-26 W.P.M.)  
SHOWING  
TRANSITIONAL OIL/WATER INTERFACE





R.26 W.P.M.

T.12

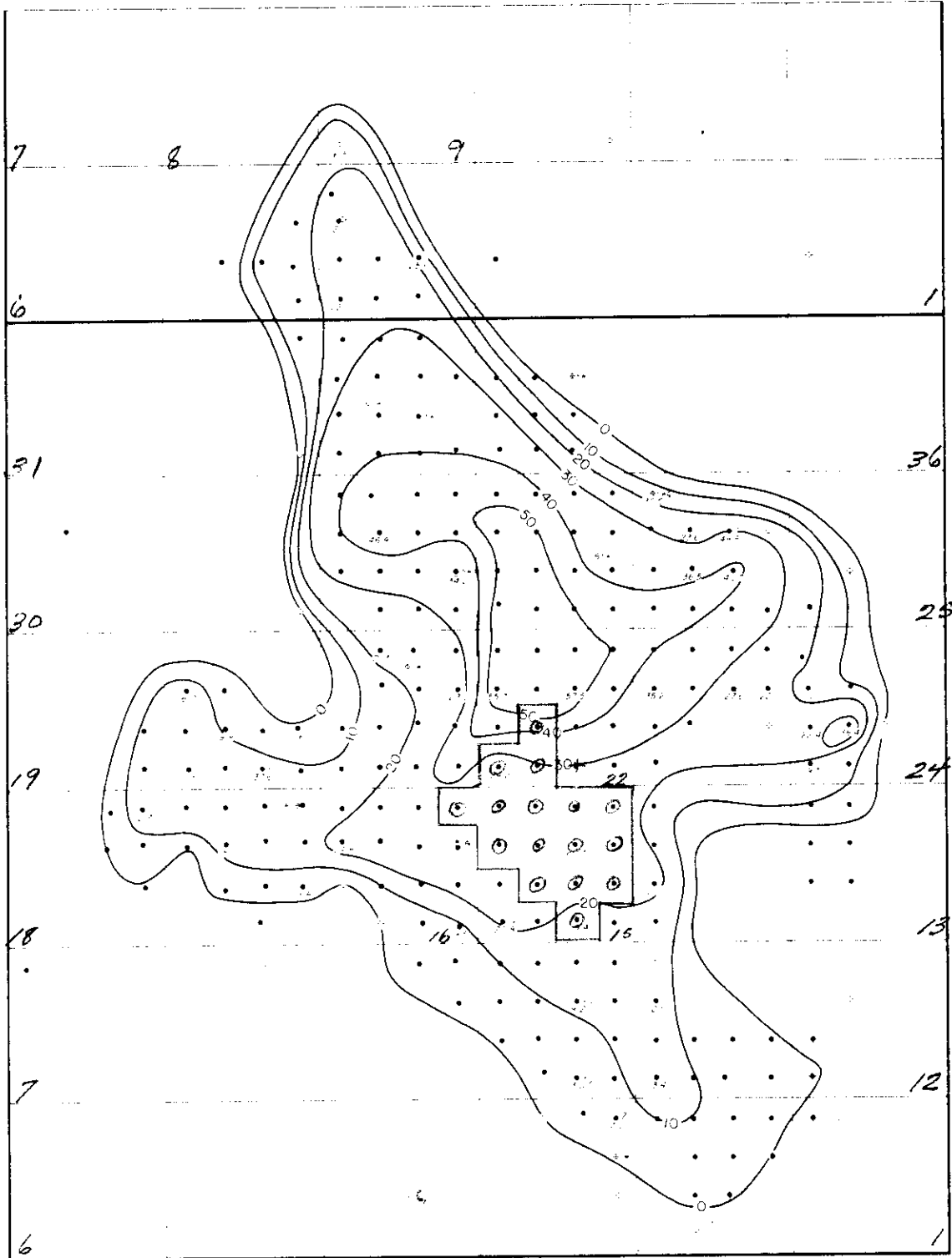


FIGURE 6

# NORTH VIRDEN SCALLION FIELD

CHERTY ZONE

ISOPACH OF NET EFFECTIVE PAY  
(FROM CORE ANALYSIS)

OF OF

BY M. E. McELROY

W. E. M. J. E.

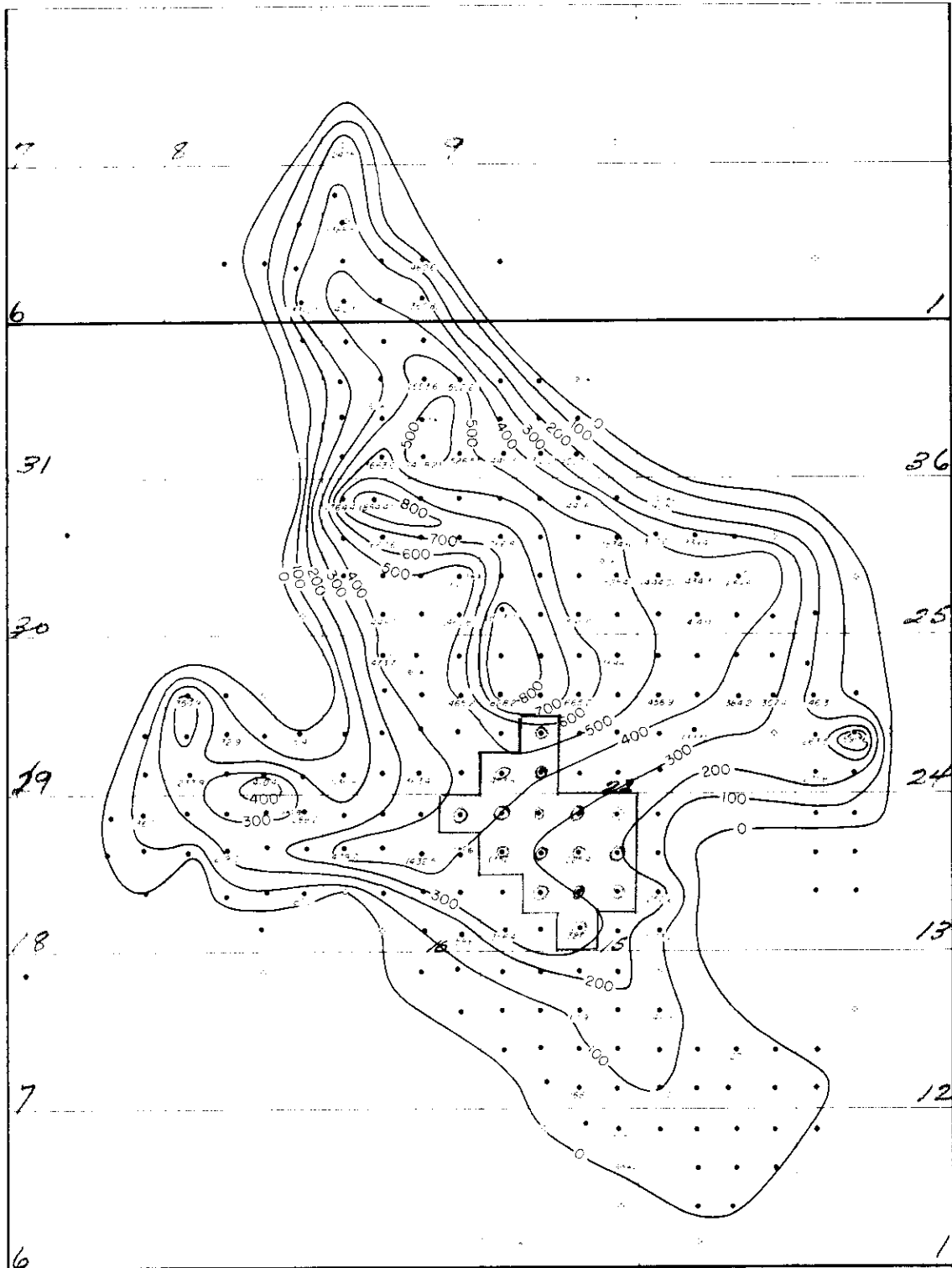
DATE: 1957



B-7590-1

R.26 W.P.M.

T.12



T.11

FIGURE 7

**NORTH VIRDEN SCALLION FIELD**  
**CHERTY ZONE**  
**ISOPACH OF POROSITY THICKNESS**  
**WITHIN EFFECTIVE PAY**

CL 100% F

BY M E McELROY

SCALE IN FEET

**-LEGEND-**

- VALUE FROM CORE ANALYSIS (COMPLETE SECTION)
- EXTRAPOLATED FROM PAY THICKNESS AND AVERAGE POROSITY WITHIN PAY ANALYZED (INCOMPLETE SECTION)

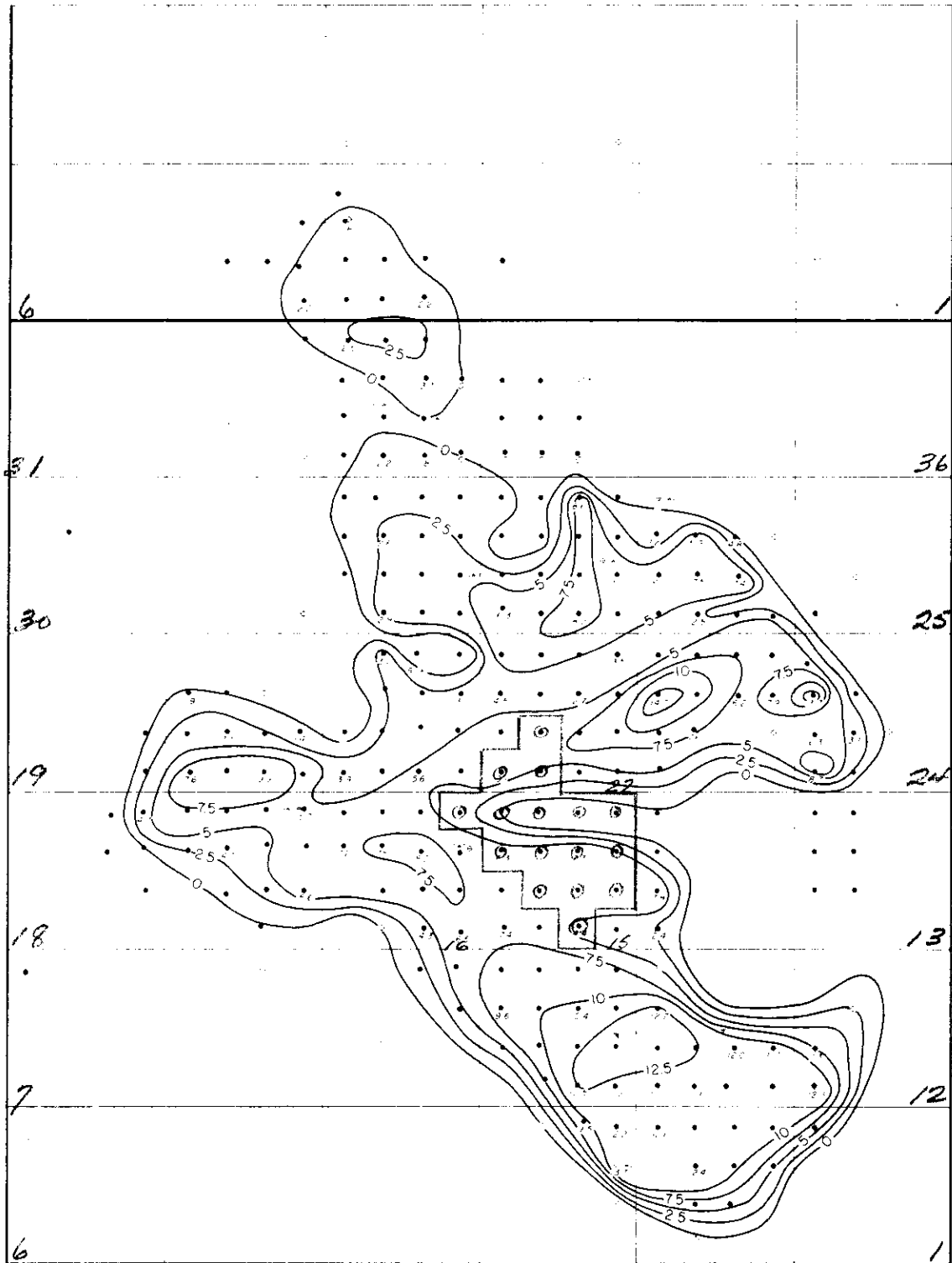


FIGURE 8  
 NORTH VIRDEN SCALLION FIELD  
 OOLITIC ZONE  
 ISOPACH OF NET EFFECTIVE PAY  
 (FROM CORE ANALYSIS)

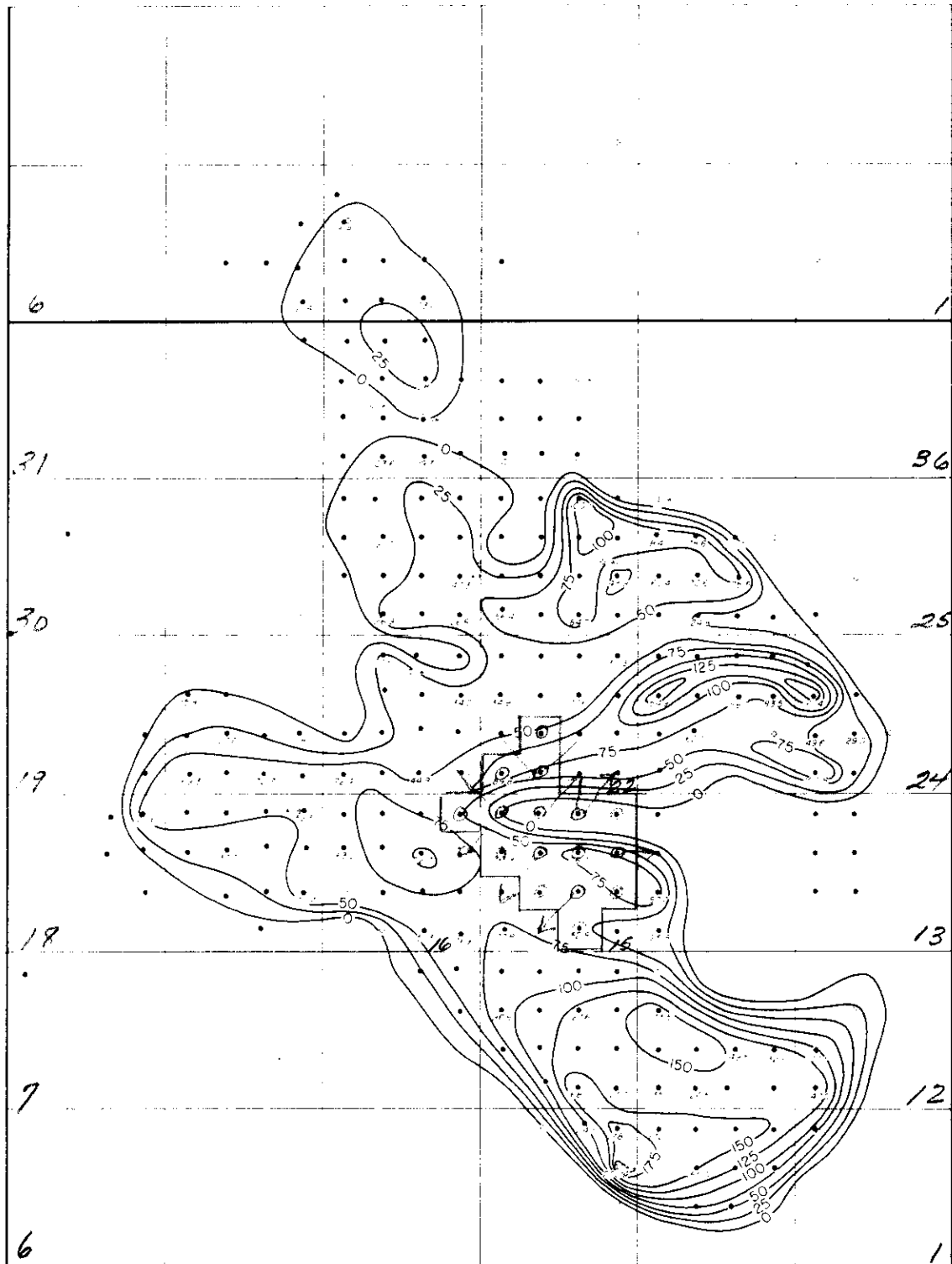
C1 25 FT

BY M E McELROY

SCALE IN FEET

R.26 W.P.M.

T.12



T.11

FIGURE 9

# NORTH VIRDEN SCALLION FIELD

OOLITIC ZONE

ISOPACH OF POROSITY THICKNESS  
WITHIN EFFECTIVE PAY

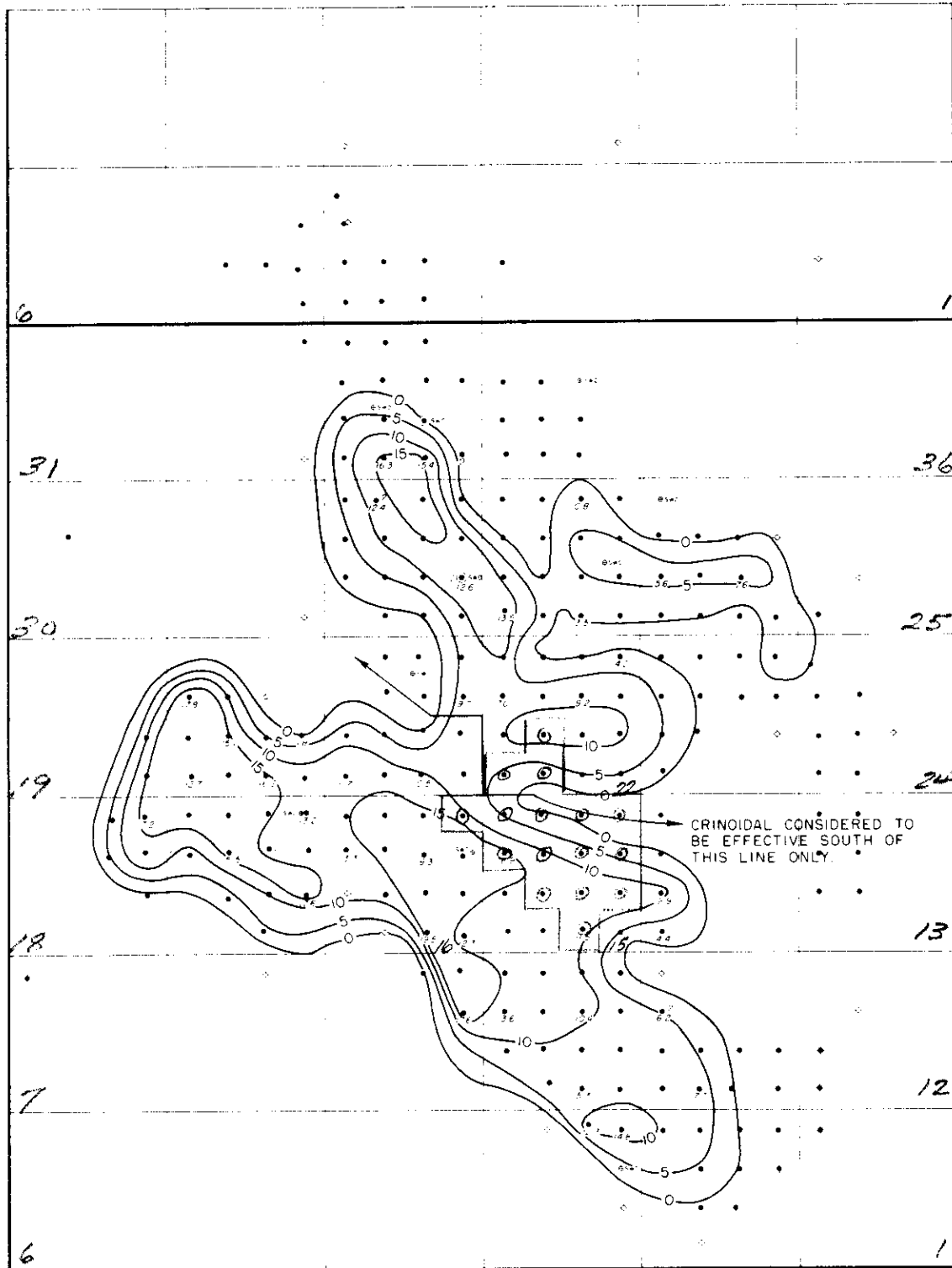
0.1-25% FT

BY M E McELROY

1/4 IN. = 1/4 MI.

R.26 W.P.M.

T.12



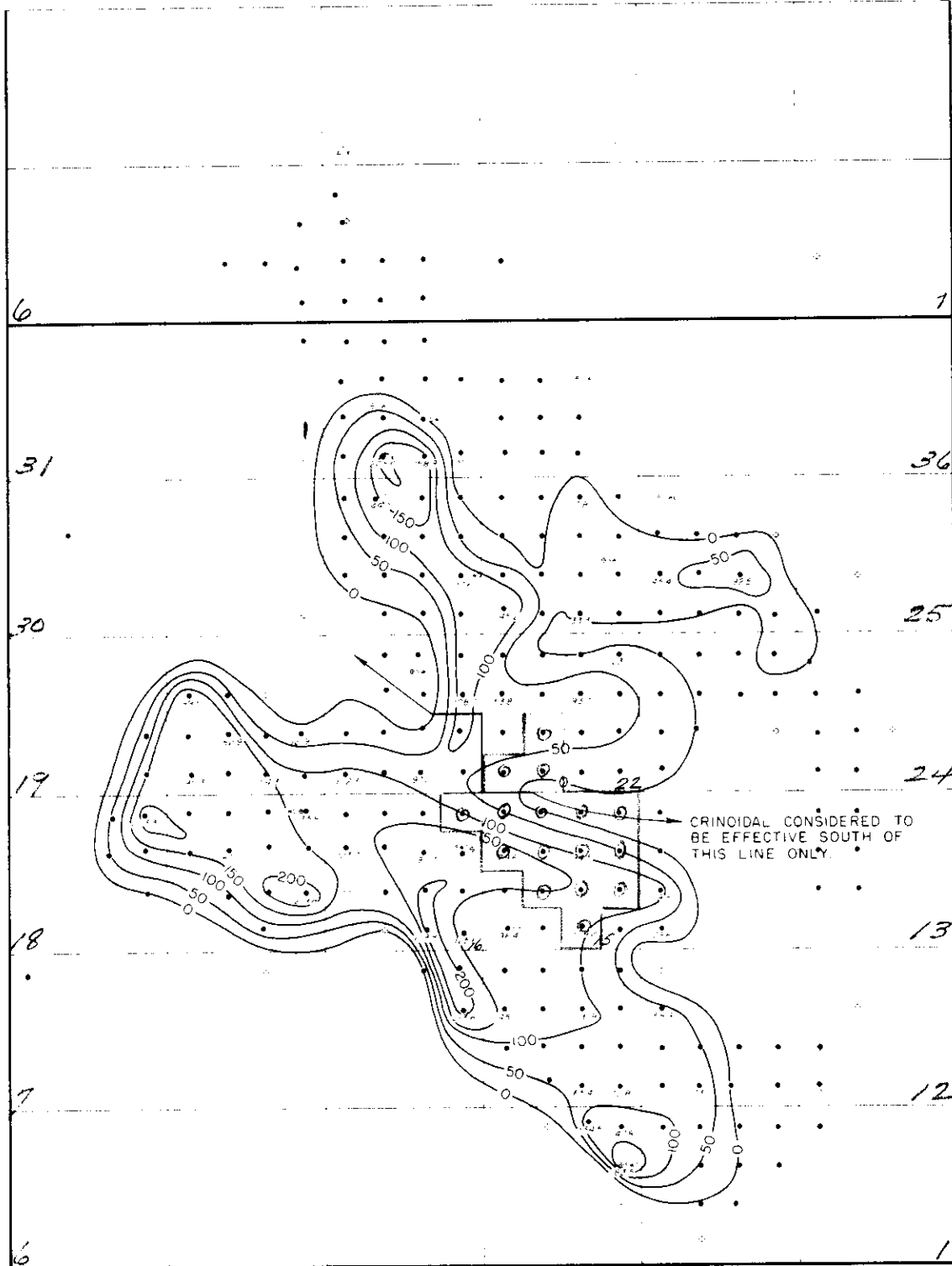
T.11

FIGURE 10  
 NORTH VIRDEN SCALLION FIELD  
 CRINOIDAL MEMBER  
 ISOPACH OF NET EFFECTIVE PAY  
 (FROM CORE ANALYSIS)

CI 5 FT

BY M E McELROY

SCALE IN MILES



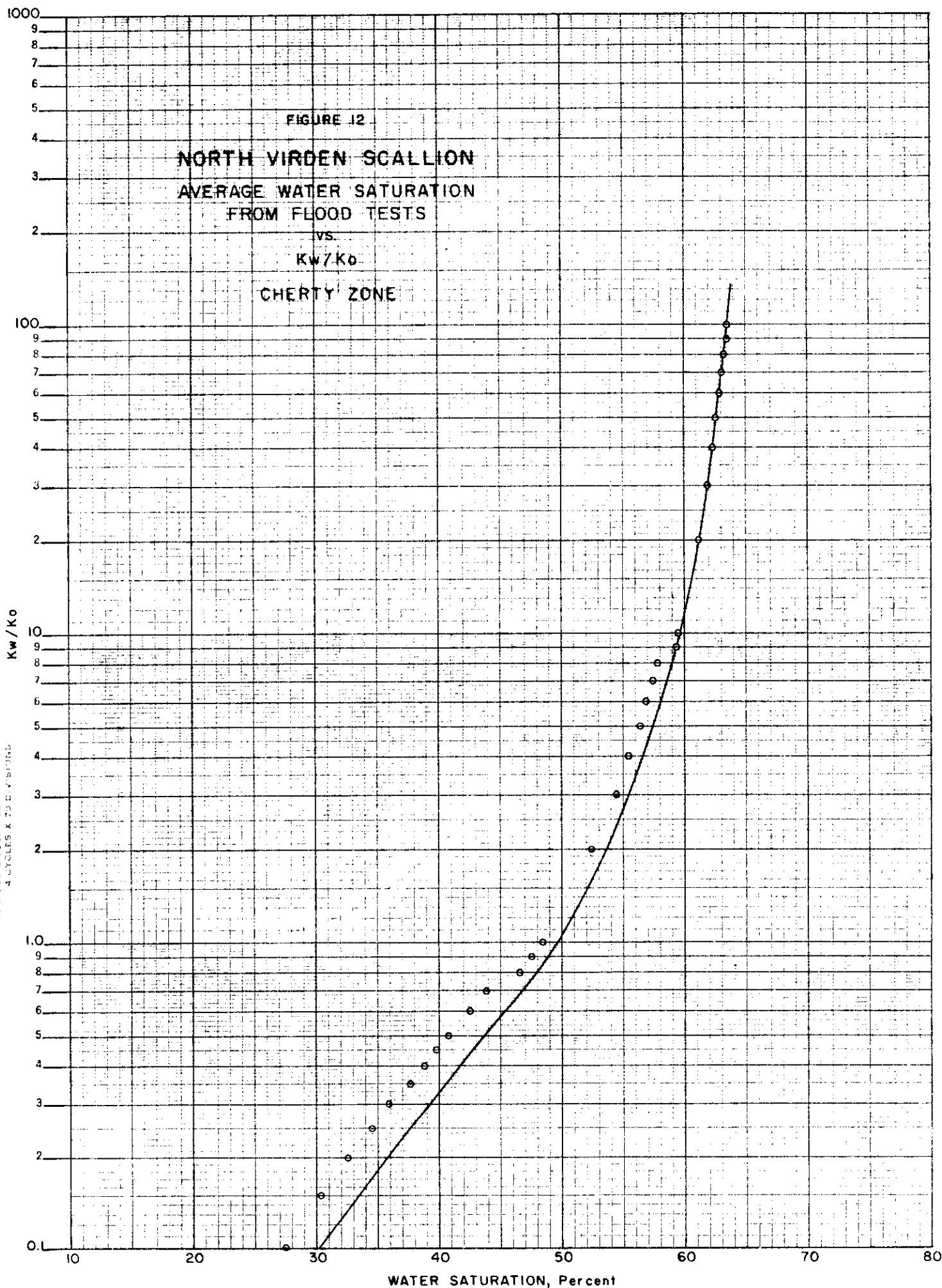
T.11

FIGURE II  
 NORTH VIRDEN SCALLION FIELD  
 CRINOIDAL MEMBER  
 ISOPACH OF POROSITY THICKNESS  
 WITHIN EFFECTIVE PAY

C.I. 50% F1

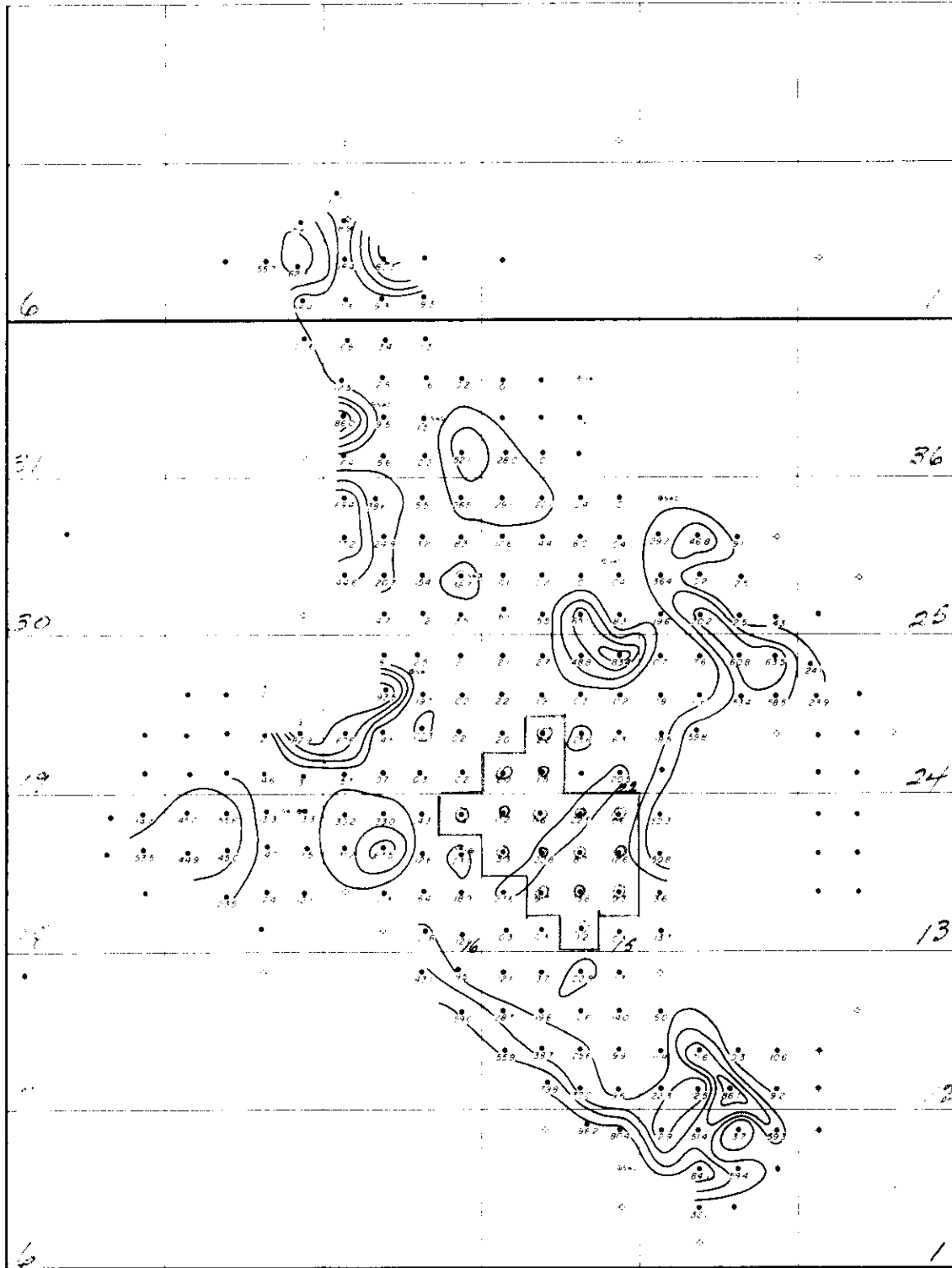
BY M. E. McELROY

SCALE IN FEET



R.26 W.P.M.

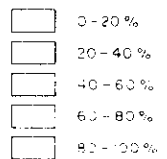
T.12



T.11

FIGURE 13  
NORTH VIRDEN SCALLION FIELD  
PRODUCTION WATER CUTS  
AT  
JUNE 1957

-LEGEND-



BY M. E. McELROY

SCALE IN MILES

C 1 20 %

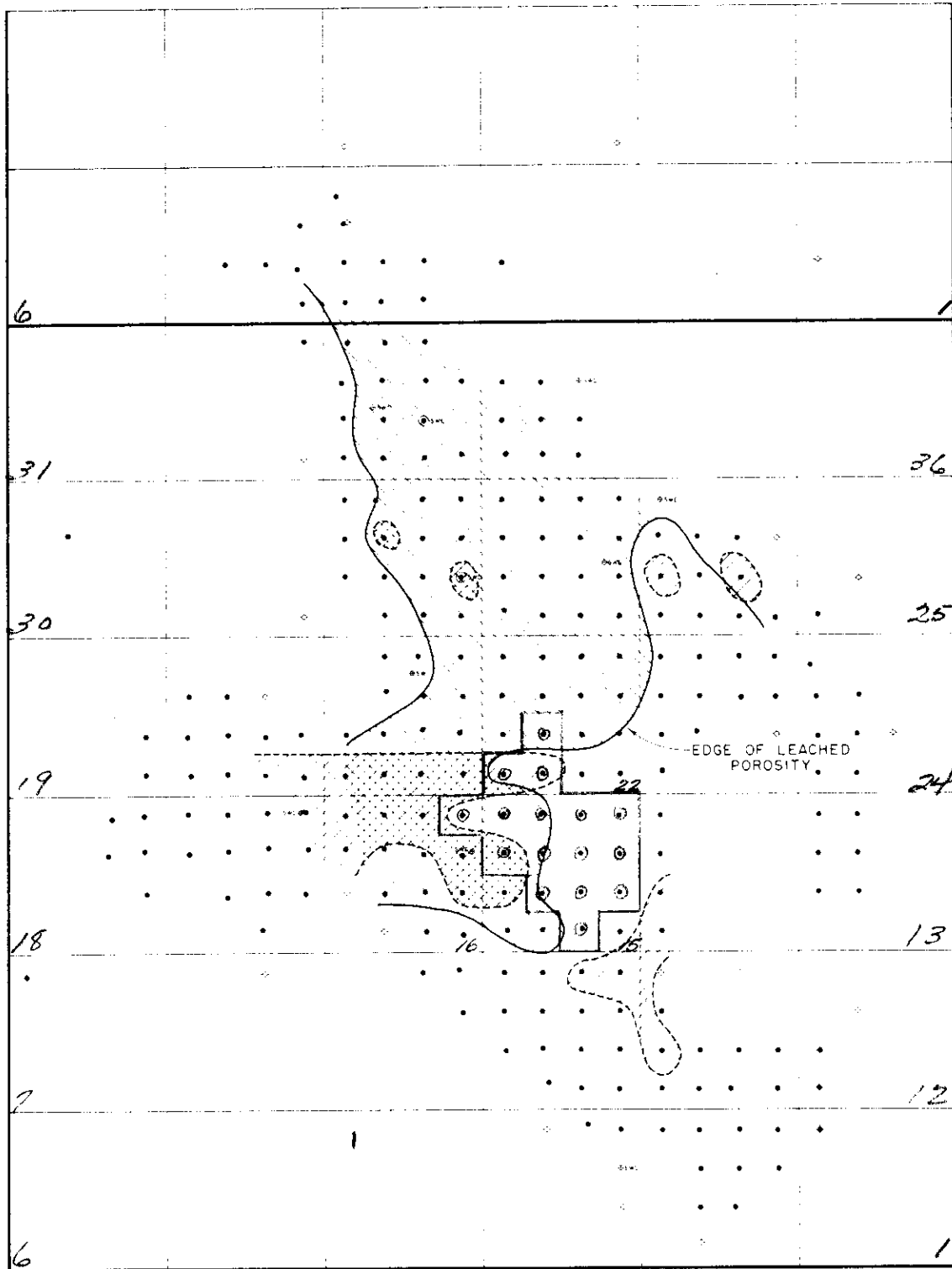
JUNE, 1957

B-7590-7



R.26 W.P.M.

T.12



T.11

FIGURE 14

# NORTH VIRDEN SCALLION FIELD

CHERTY ZONE

SHOWING AREAS OF OPEN FRACTURING  
AND LEACHED POROSITY

-LEGEND-

OPEN FRACTURES  
LEACHING

SCALE IN MILES

JUNE, 1957

B-7590-8

FIGURE 15

# NORTH VIRDEN SCALLION TOTAL PRODUCTION RATE vs. CUMULATIVE

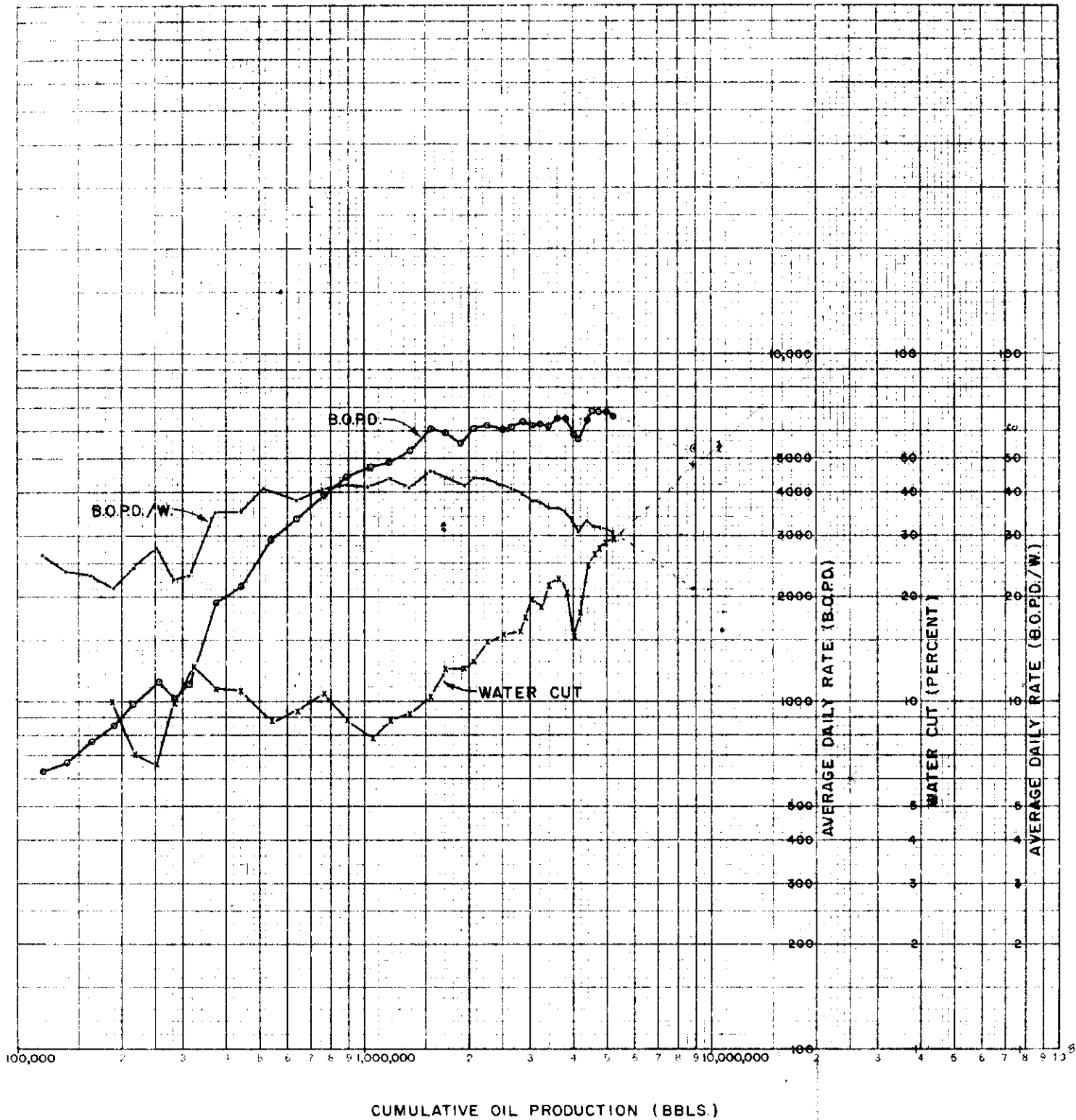
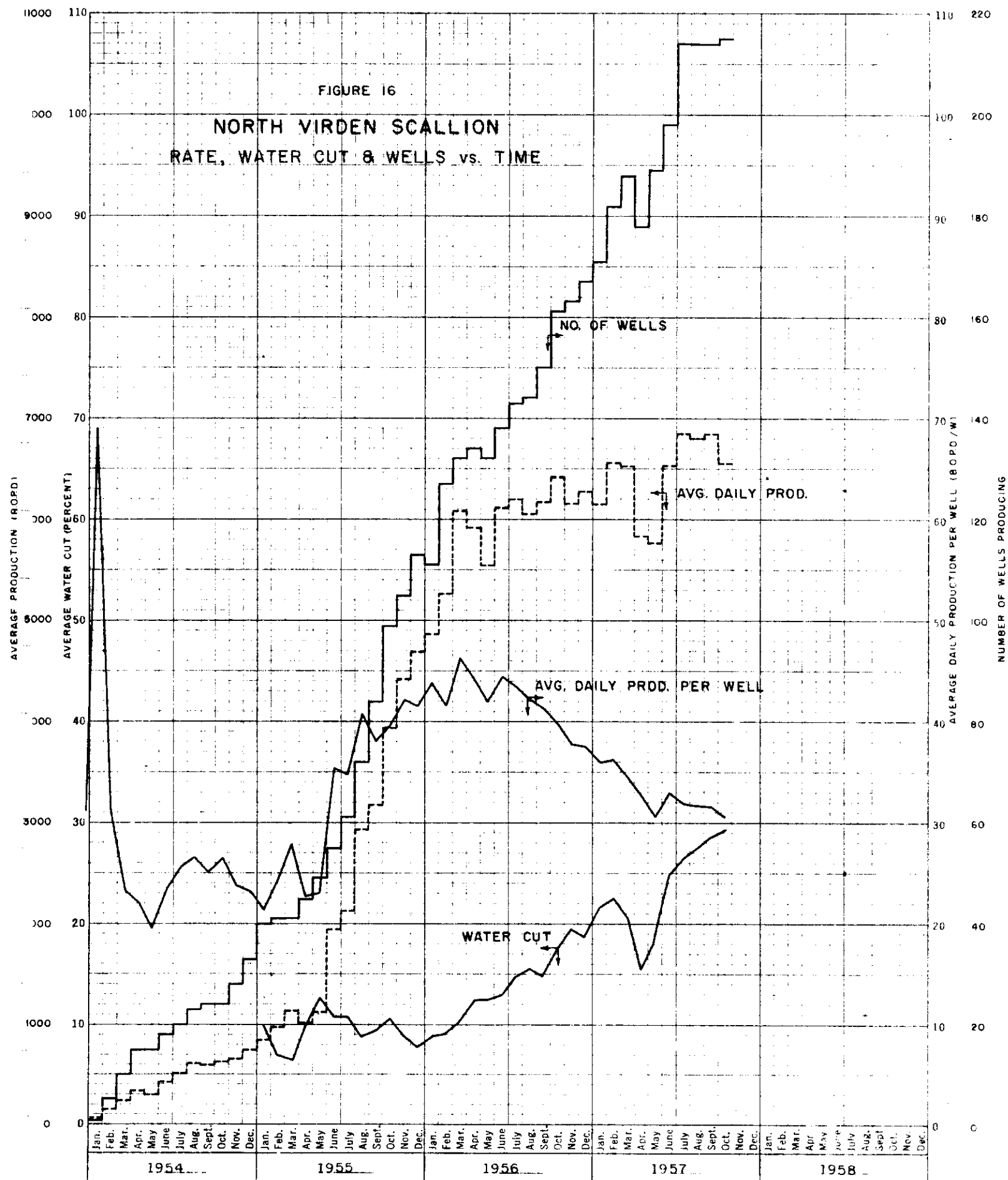


FIGURE 16

# NORTH VIRDEN SCALLION RATE, WATER CUT & WELLS vs. TIME



FIELD PRODUCTION RATE, B.O.P.D.

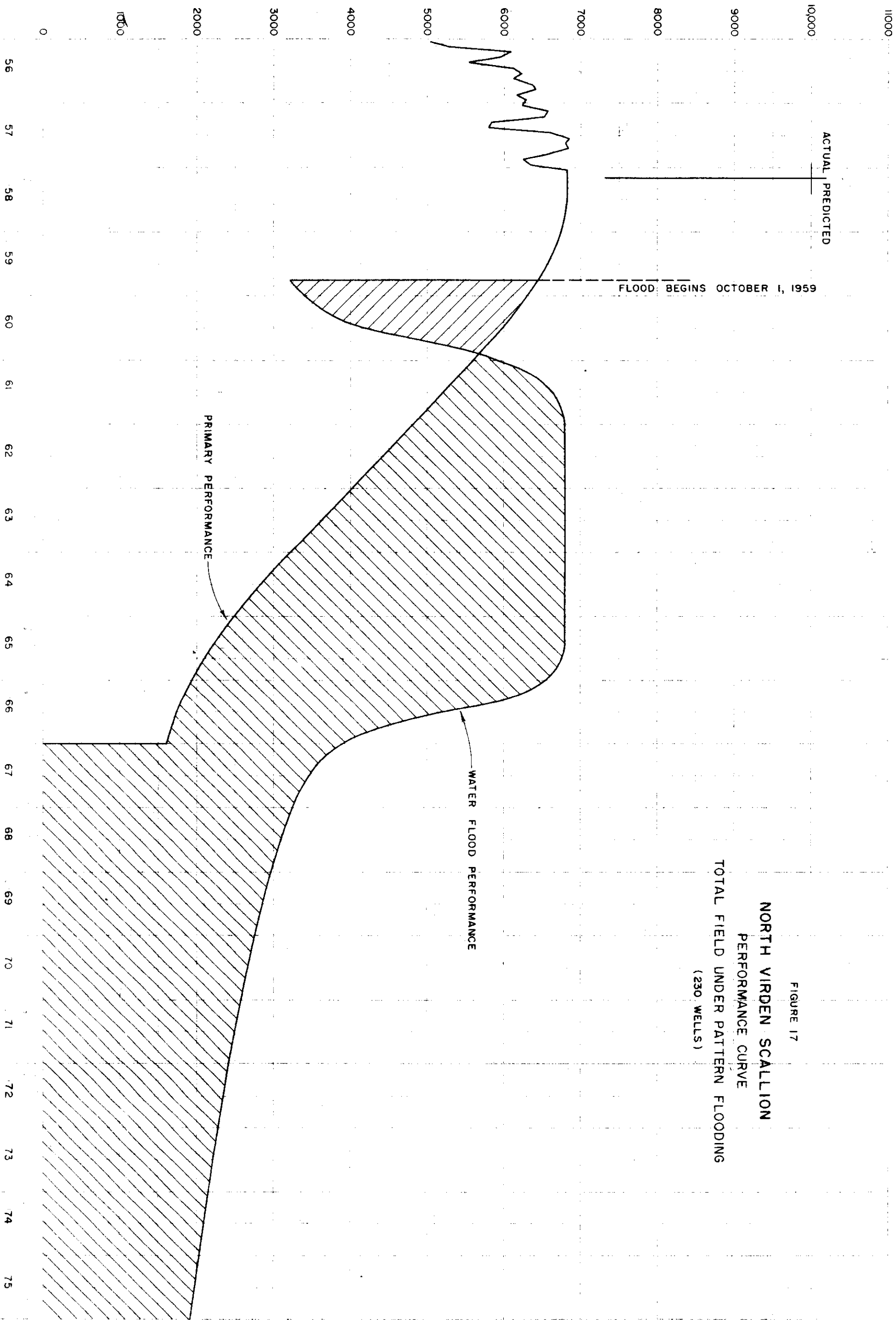
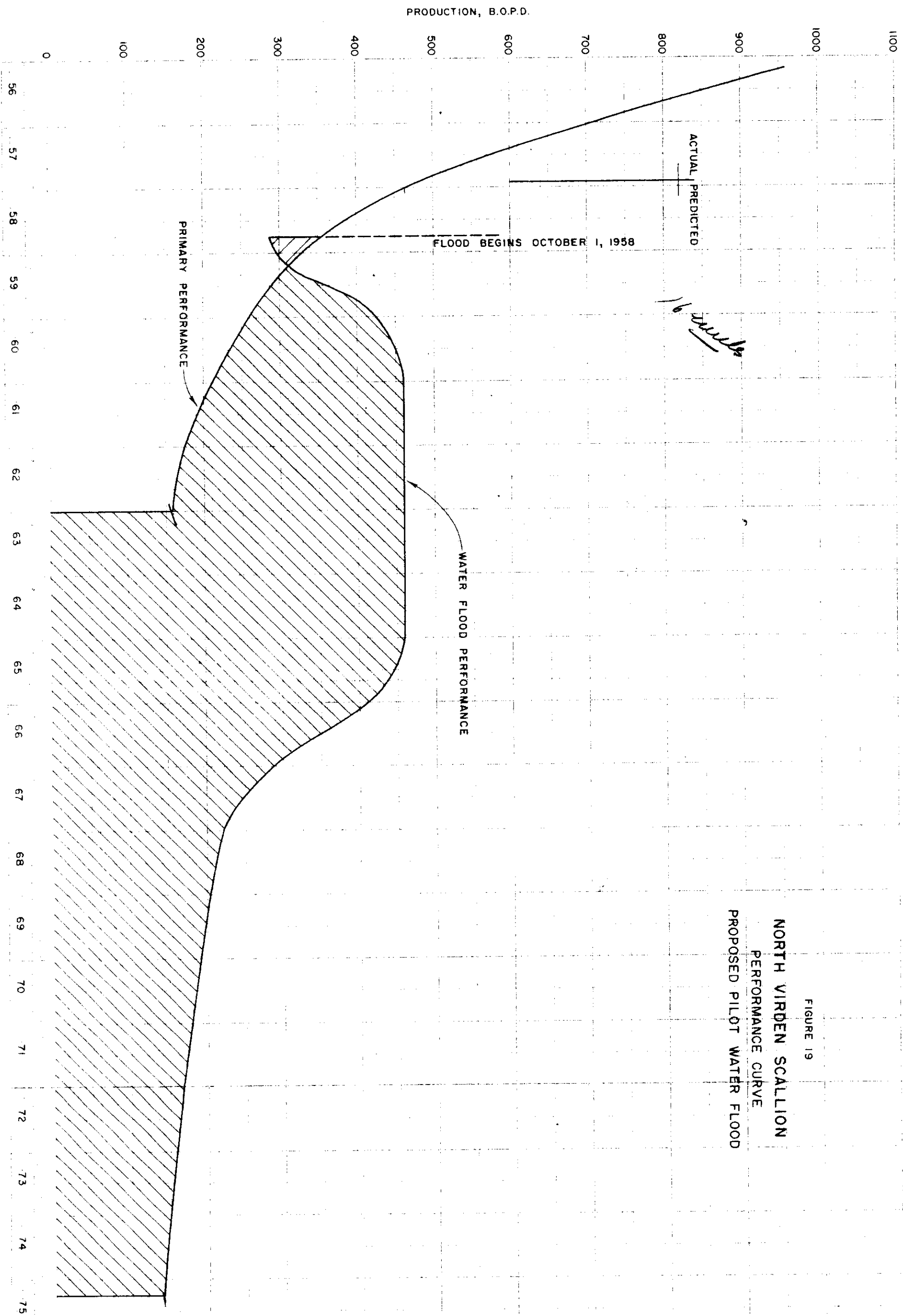
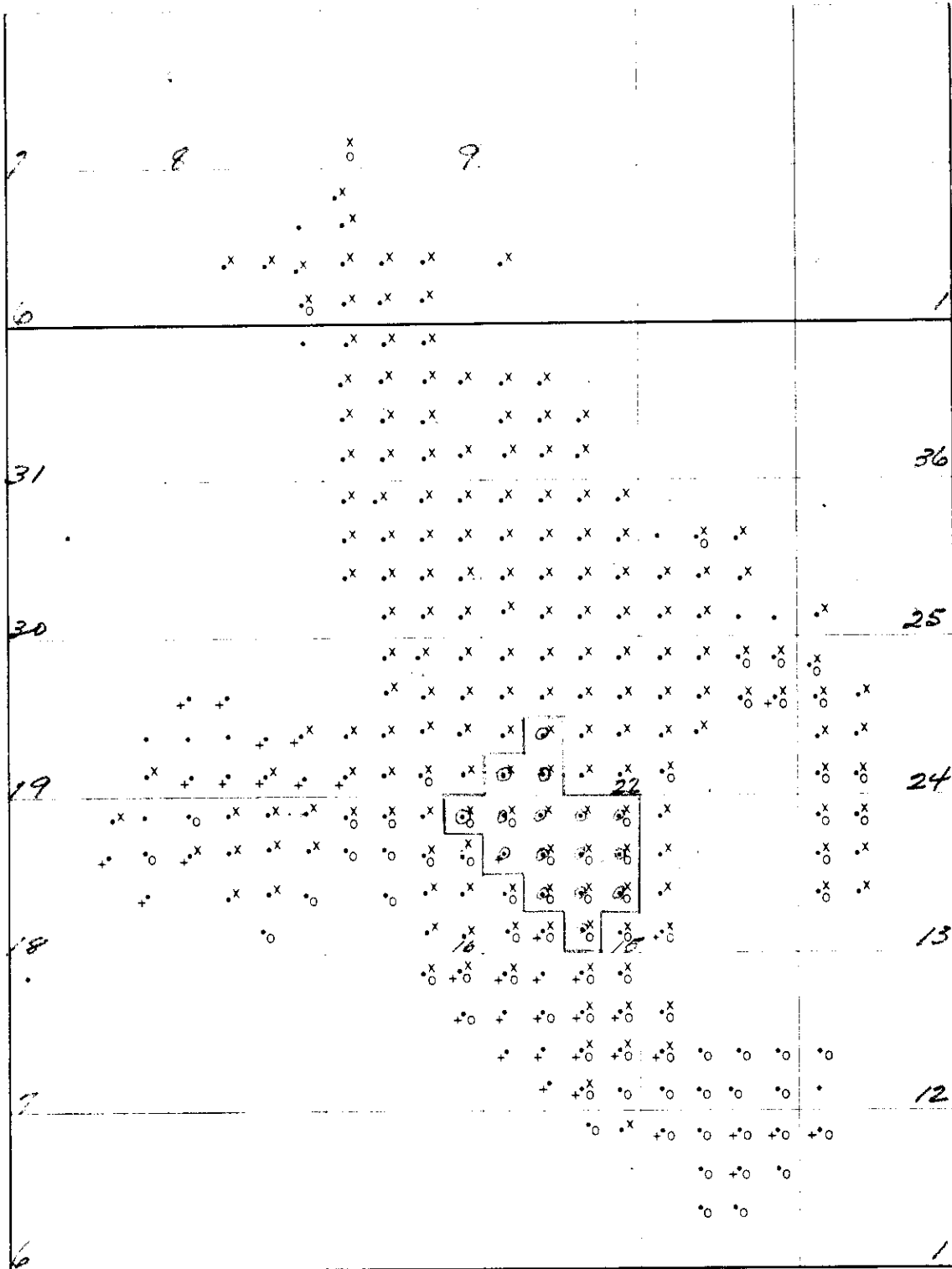


FIGURE 17  
NORTH VIRDEN SCALLION  
PERFORMANCE CURVE  
TOTAL FIELD UNDER PATTERN FLOODING  
(230 WELLS)



R.26 W.P.M.

T.12



T.11

FIGURE 20  
NORTH VIRDEN SCALLION FIELD

SHOWING  
ZONE OF COMPLETIONS

BY M. F. McELROY

-LEGEND-

- x COMPLETION
- o COMPLETION
- + COMPLETION

FIGURE 21

SCALLION 9-23

NORTH VIRDEN FIELD

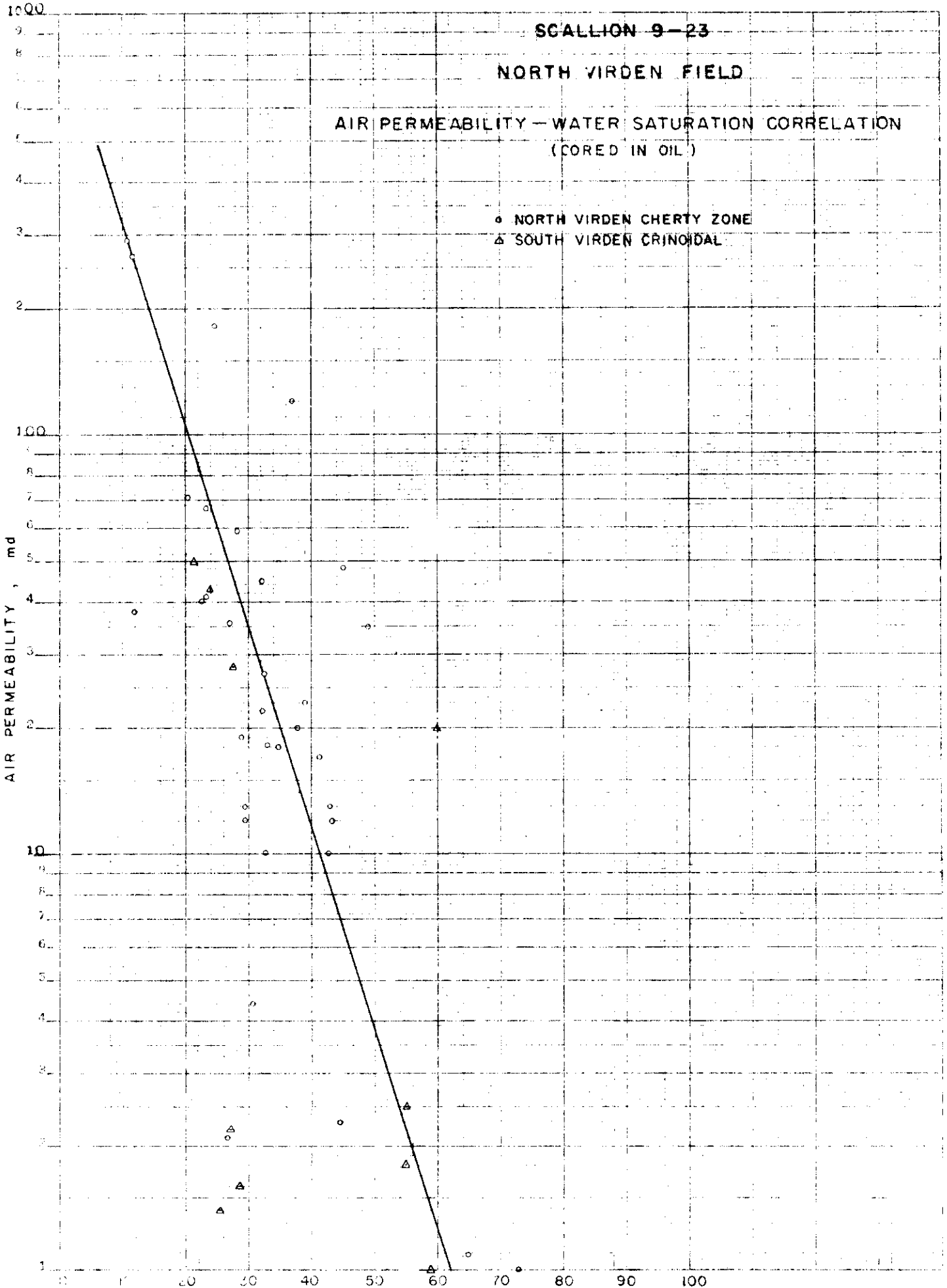
AIR PERMEABILITY - WATER SATURATION CORRELATION  
(CORED IN OIL)

○ NORTH VIRDEN CHERTY ZONE

△ SOUTH VIRDEN CRINOIDAL

AIR PERMEABILITY, md

WATER SATURATION, PERCENT



PERCENTAGE GREATER THAN

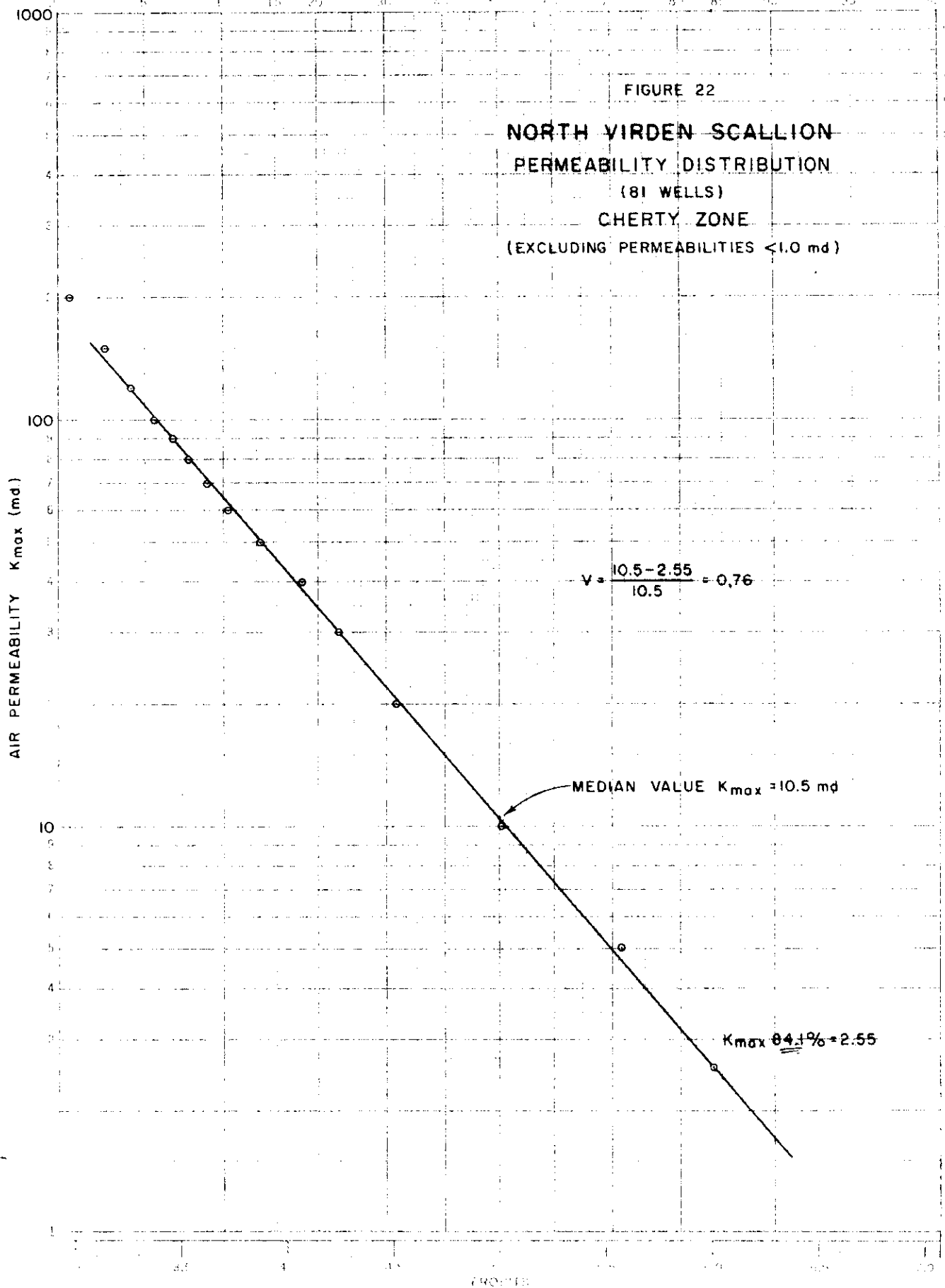
FIGURE 22

**NORTH VIRDEN SCALLION  
PERMEABILITY DISTRIBUTION**

(81 WELLS)

**CHERTY ZONE**

(EXCLUDING PERMEABILITIES <1.0 md)





PERCENTAGE GREATER THAN

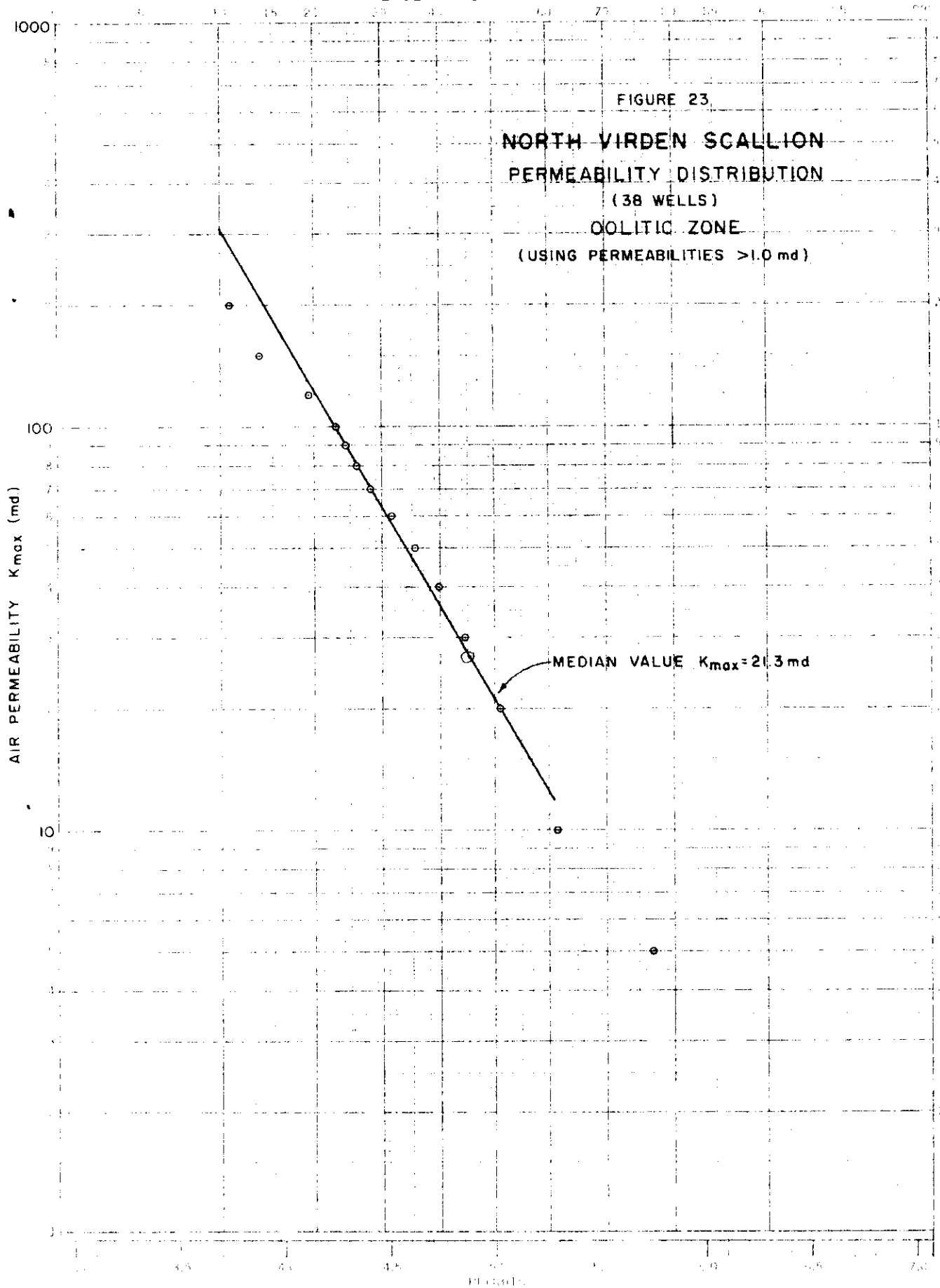


FIGURE 24

SCALLION 9-23

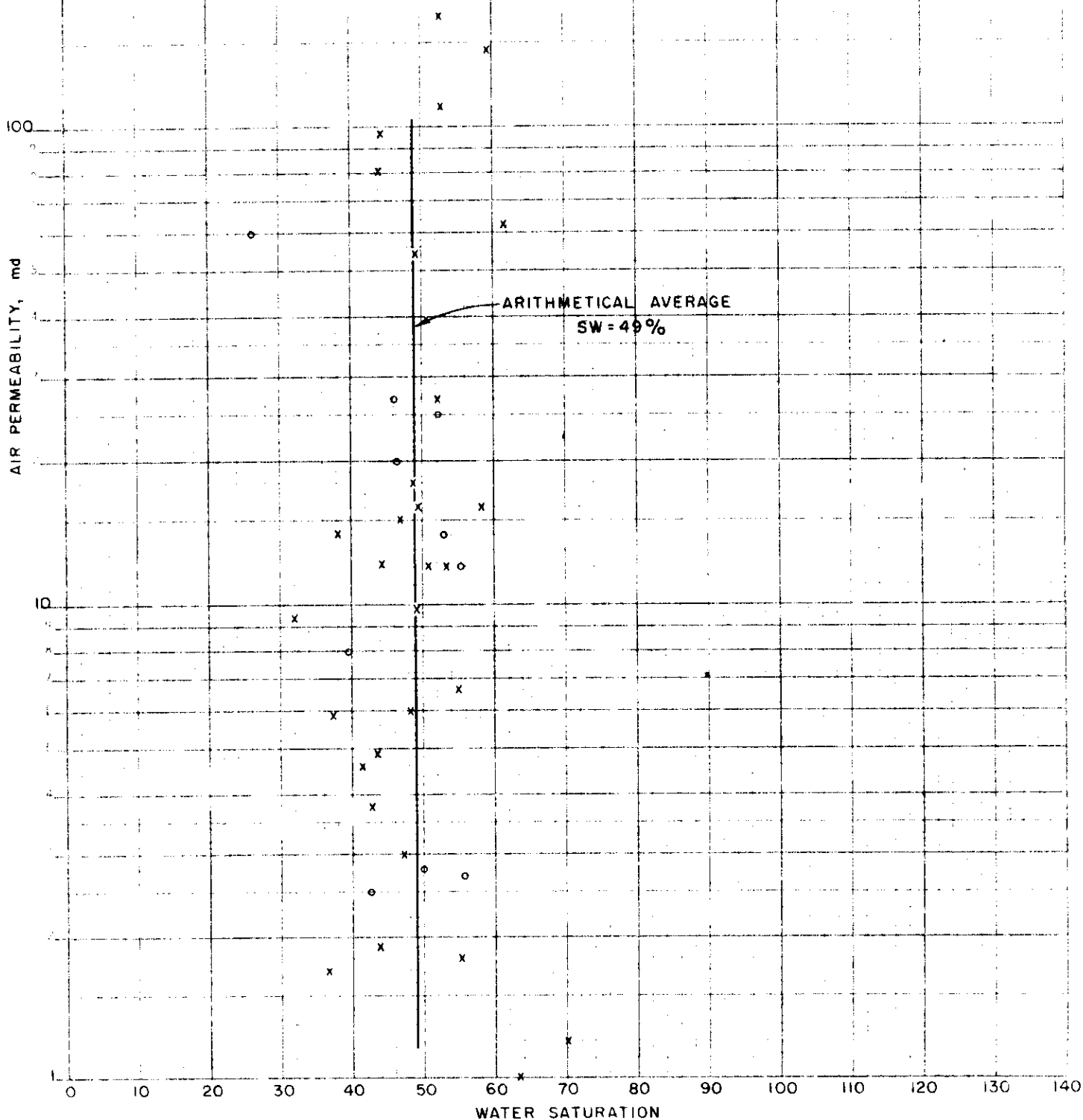
SOUTH VIRDEN 15-11 &amp; 12-1

AIR PERMEABILITY vs. WATER SATURATION

OOLITIC ZONE

o SCALLION 9-23

x SOUTH VIRDEN WELLS



PERCENTAGE GREATER THAN

FIGURE 25

**NORTH VIRDEN SCALLION  
PERMEABILITY DISTRIBUTION  
(38 WELLS)  
CRINOIDAL ZONE  
(USING PERMEABILITIES >1.0 md)**

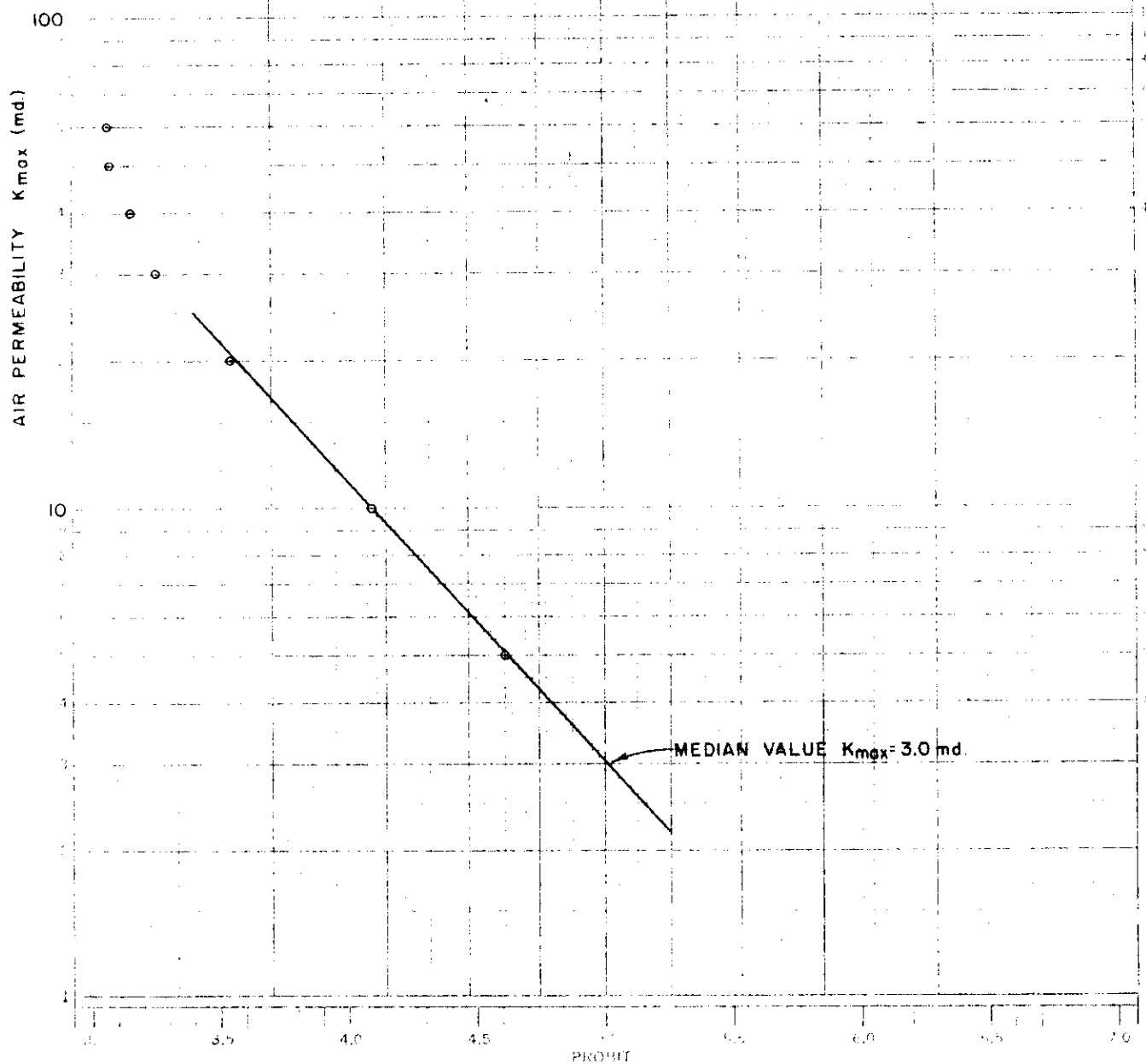


FIGURE 26

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

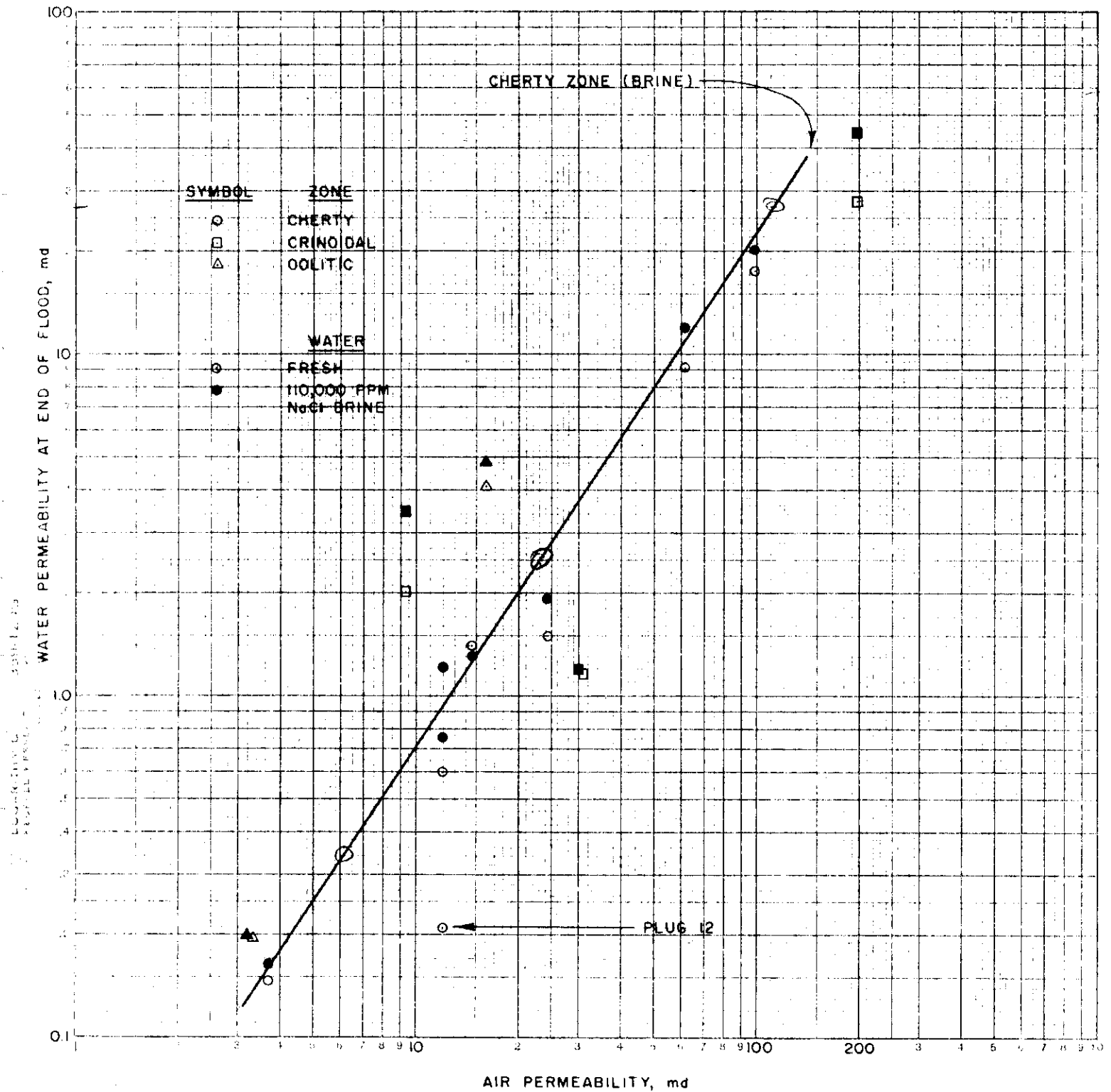
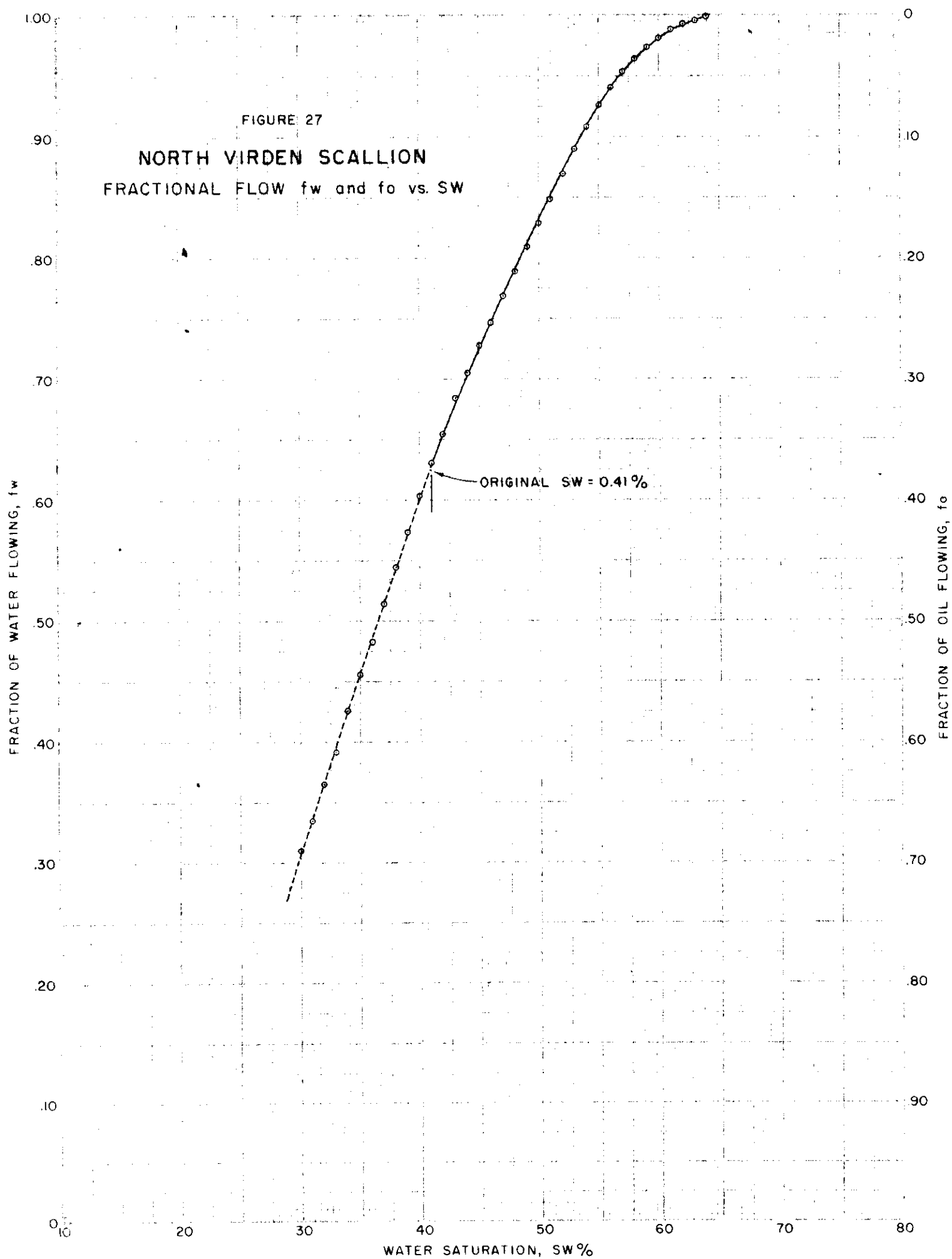


FIGURE 27

NORTH VIRDEN SCALLION  
FRACTIONAL FLOW  $f_w$  and  $f_o$  vs. SW



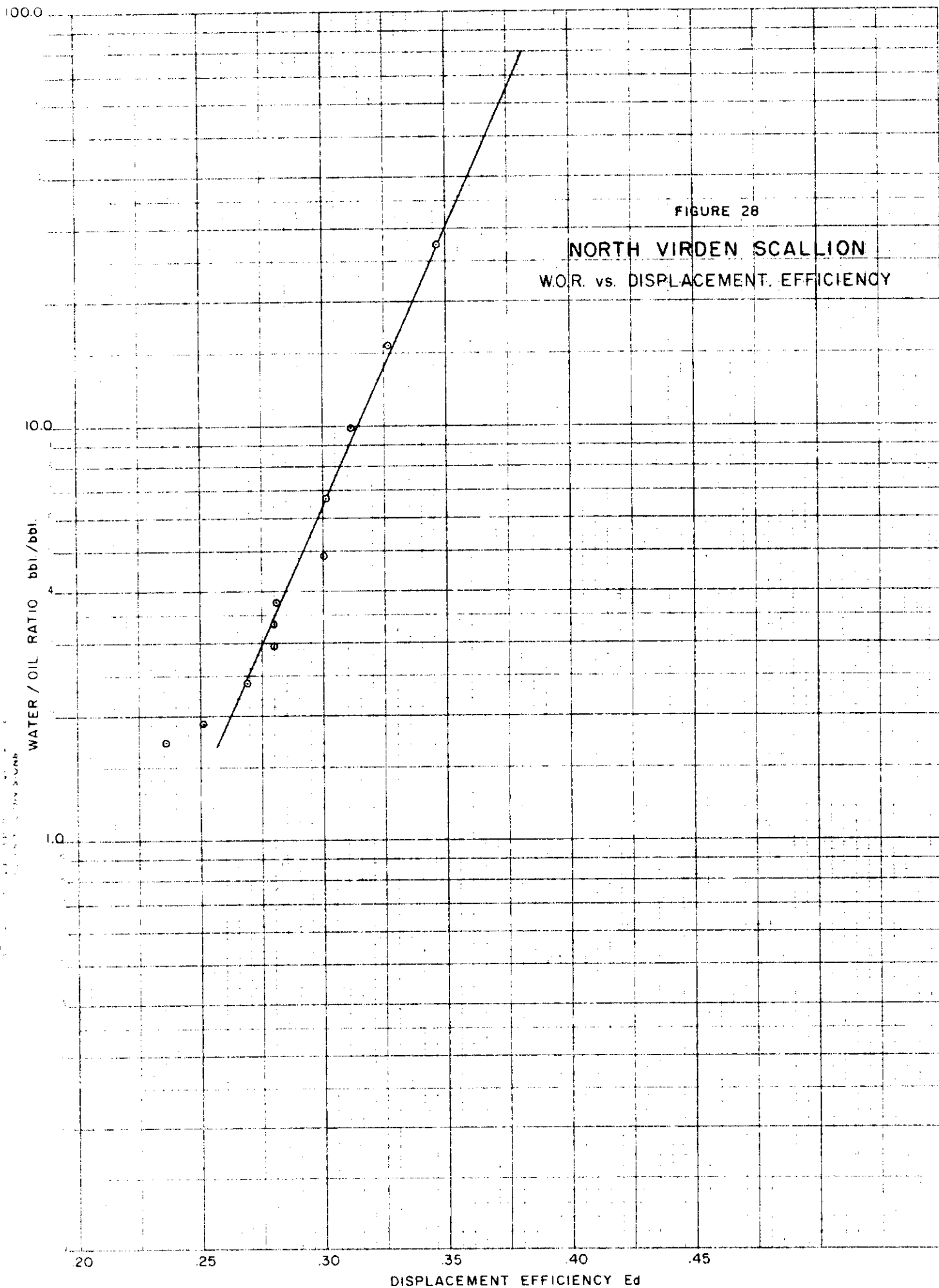
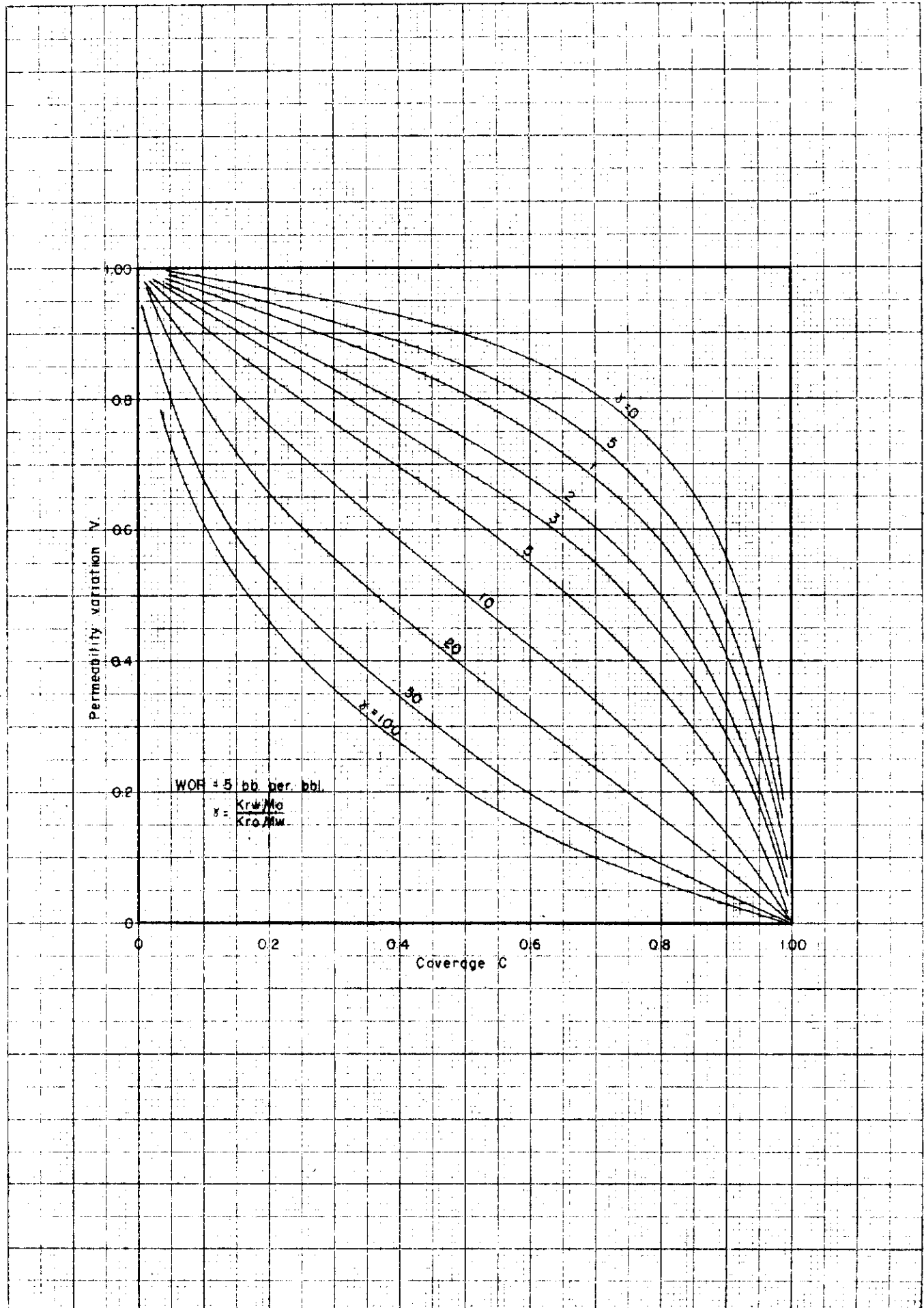


FIGURE 28  
NORTH VIRDEN SCALLION  
W.O.R. vs. DISPLACEMENT EFFICIENCY

$$\sigma = \frac{K_{rw} M_o}{K_o M_w}$$

[illegible]



### PERMEABILITY VARIATION VS. COVERAGE

Figure 1 is a graph showing the relationship between Permeability variation,  $V$ , and Coverage,  $C$ . The y-axis represents Permeability variation,  $V$ , ranging from 0 to 1.0. The x-axis represents Coverage,  $C$ , ranging from 0 to 1.0. The graph displays several curves corresponding to different values of the parameter  $r$ , which is defined as  $r = \frac{K_{rw}/M_o}{K_{ro}/M_w}$ . The curves are labeled with values of  $r$ : 0, 1, 2, 3, 5, 10, 20, 50, and 100. The curves show that permeability variation decreases as coverage increases, and the rate of decrease is more pronounced for higher values of  $r$ . A note indicates  $WOR = 25 \text{ bbl per bbl}$ .

## PERMEABILITY VARIATION VS. COVERAGE

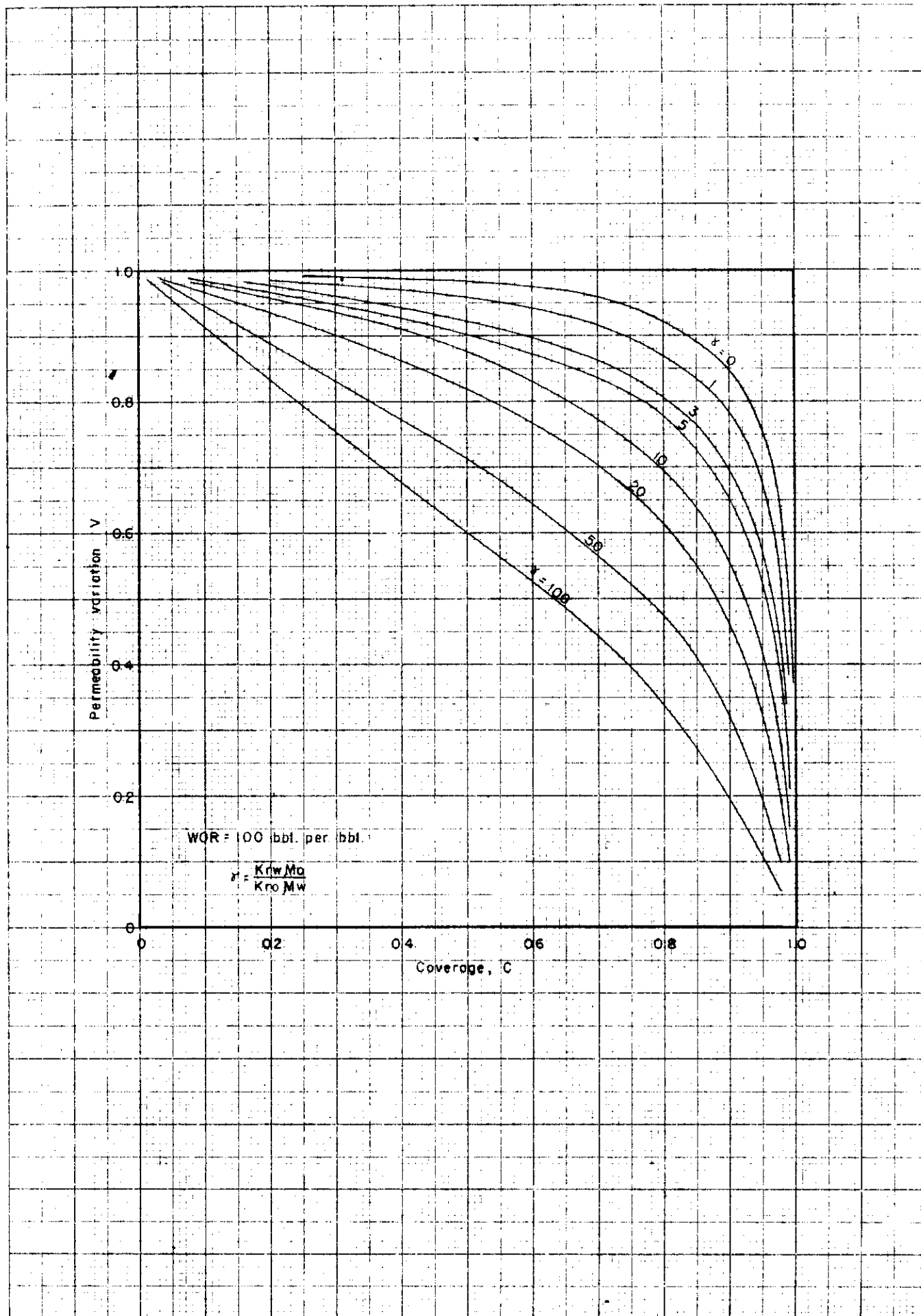
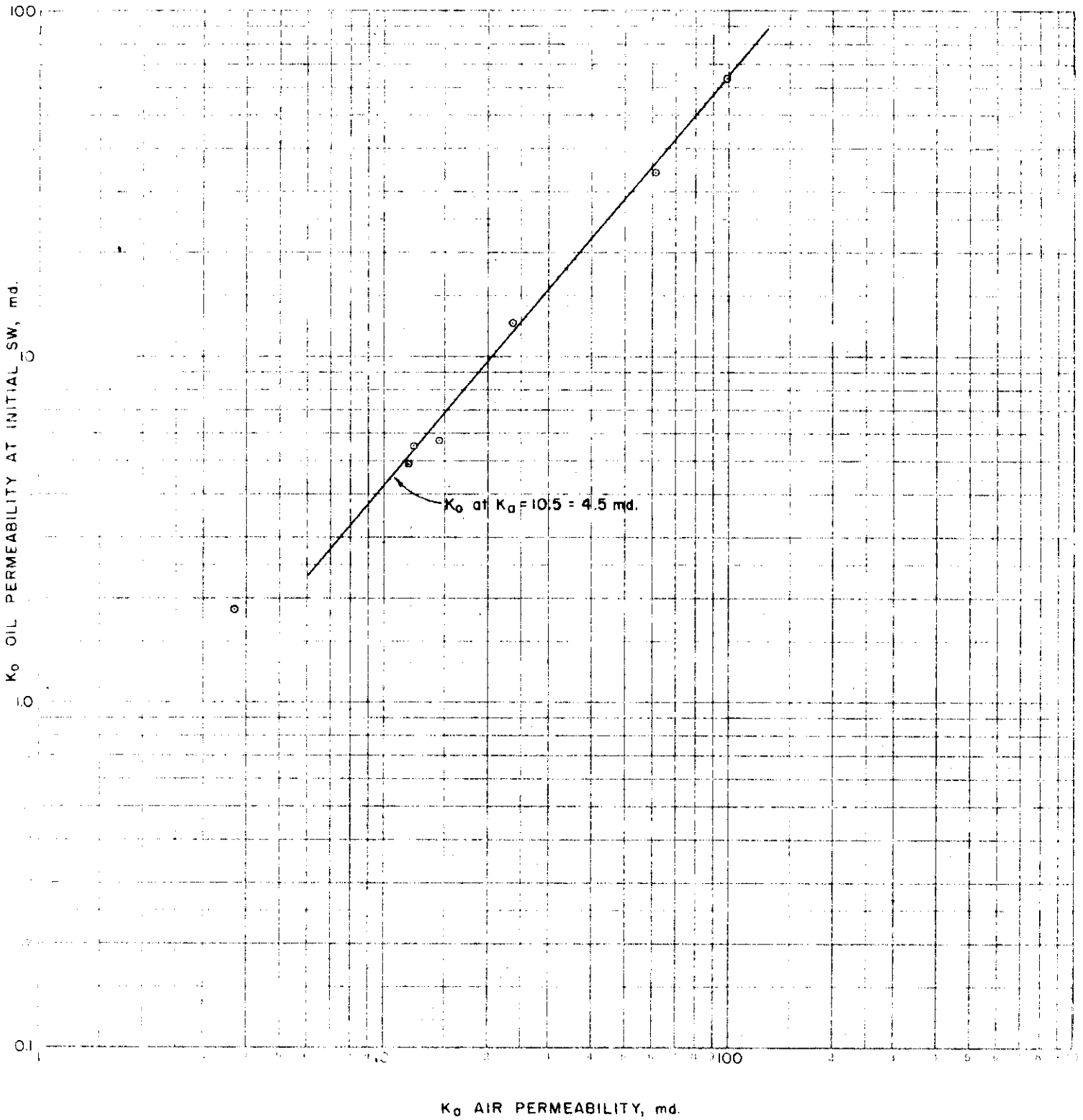


FIGURE 30

# NORTH VIRDEN SCALLION OIL PERMEABILITY vs. AIR PERMEABILITY



## W.O.R. vs. COVERAGE

 $\lambda = 0.77$ 

WATER / OIL RATIO bbl./bbl.

1.0

03

0.4

0.5

0.6

0.7

0.8

0.9

1.0

VERTICAL SWEEP EFFICIENCY (COVERAGE-C)  $E_v$

WATER / OIL RATIO bbl/bbl.

FIGURE 32

NORTH VIRDEN SCALLION  
W.O.R vs. AREAL SWEEP EFFICIENCY

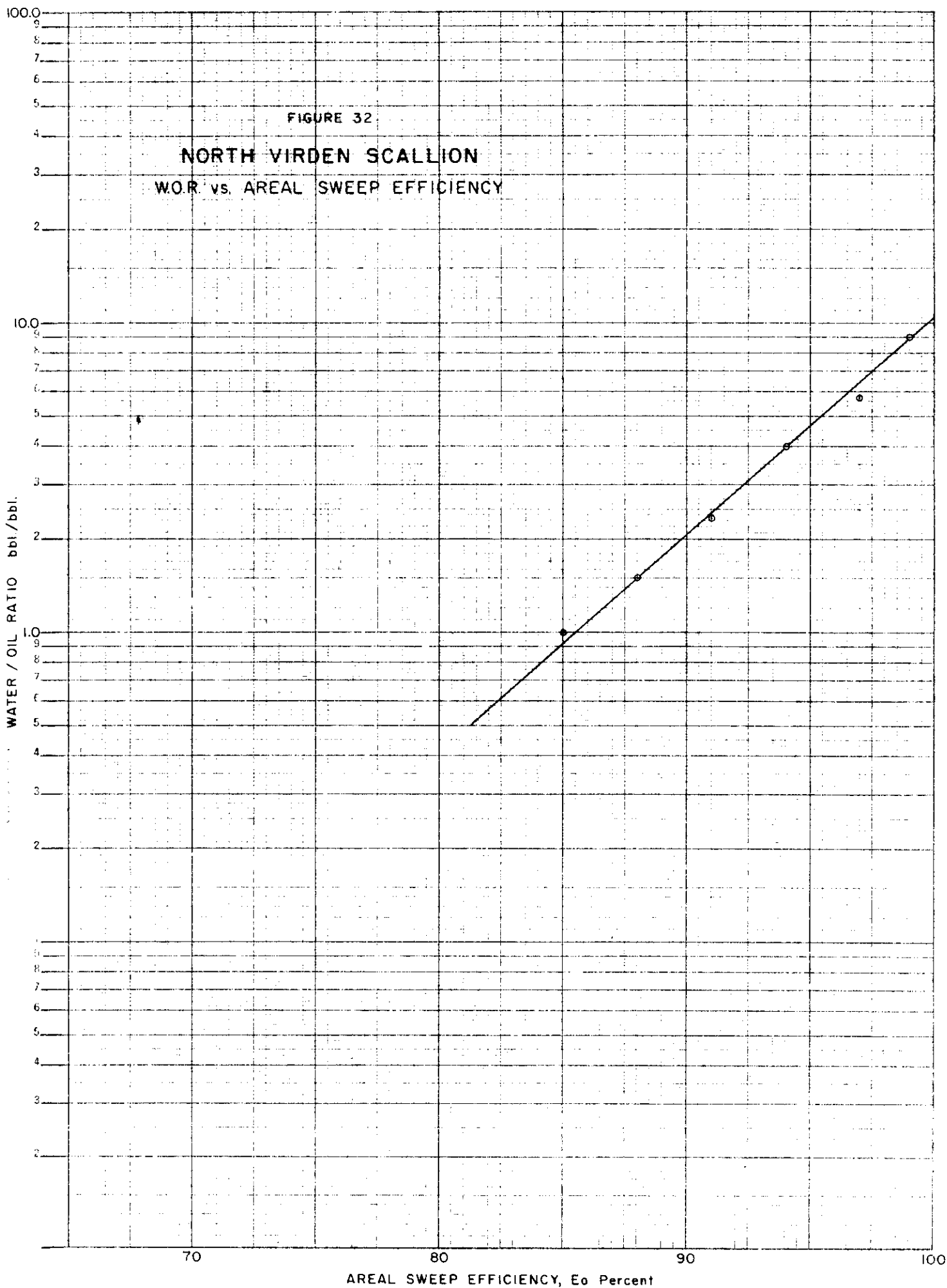


FIGURE 33

NORTH VIRDEN SCALLION  
WATER FLOOD RECOVERY

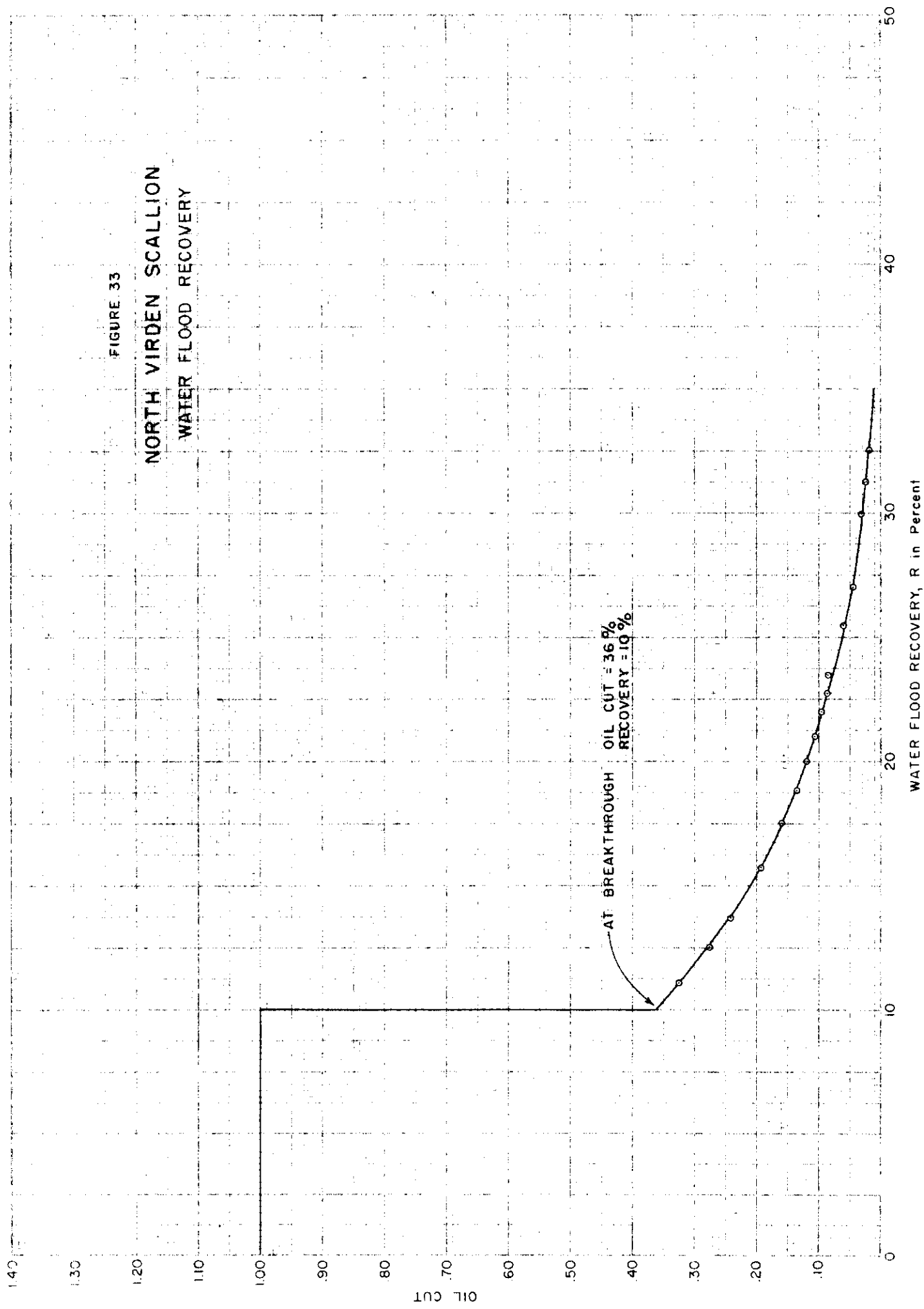


TABLE I

## NORTH VIRDEN SCALLION FIELD

## BOTTOM HOLE PRESSURE SURVEY RESULTS

Date of Survey	Bottom Hole Pressure, psig										
	Calstan 15-15	Calstan 9-16	Calstan 10-16	Sun 8-20	Calstan 3-21	Sun 10-22	Calstan 11-22	Sun 4-23	Calstan 12-27	Shell 3-33	Sun 4-9
April, 1955	-	906	-	-	-	-	-	-	-	-	-
September, 1955	-	860	-	-	838	-	-	-	-	-	-
December, 1955	-	-	833	-	-	-	703	-	-	-	-
February, 1956	-	-	-	-	789	-	-	895	671*	-	-
May, 1956	-	-	824	-	760	-	526	-	433*	-	-
September, 1956	715	-	-	-	764	461	422	747	553	727	-
December, 1956	-	-	-	-	-	-	-	677	-	-	-
July, 1957	-	-	-	-	-	-	-	590	-	-	853
September, 1957	-	-	-	-	-	-	-	572	-	-	844
January, 1958	-	-	-	682	-	-	-	525	-	-	834

\* Incomplete Build up

TABLE II

## NORTH VIRDEN SCALLION FIELD

AVERAGING  $K_w/K_o$  vs  $S_w$  CURVE

## CHERTY ZONE

$K_w/K_o$	Water Saturation, $S_w$							Total $S_w$	Average $S_w$
	#43	#47	#57	#28	#48	#12	#52		
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 BY WELGE'S METHOD

(1) $S_w$	(2) $K_w/K_o$	(3) $\frac{\mu_o K_w}{\mu_w K_o}$	(4) $f_o = \frac{1}{1 + \frac{\mu_o K_w}{\mu_w K_o}}$	(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) $\frac{Res. W.O.R.}{= 1 - f_o}$
0.41	0.37	1.71	0.369	2.65	0.139	0.549	0.451	0.236	1.71
0.42	0.415	1.91	0.344	2.50	0.138	0.558	0.442	0.251	1.91
0.43	0.47	2.17	0.315						
0.44	0.52	2.40	0.294	2.30	0.128	0.568	0.432	0.268	2.40
0.45	0.58	2.67	0.272						
0.46	0.64	2.95	0.253	2.20	0.115	0.575	0.425	0.280	2.95
0.47	0.72	3.32	0.231	2.20	0.105	0.575	0.425	0.280	3.33
0.48	0.81	3.73	0.211	2.20	0.096	0.576	0.424	0.281	3.74
0.49	0.92	4.24	0.191						
0.50	1.05	4.84	0.171	2.10	0.081	0.581	0.419	0.300	4.85
0.51	1.22	5.62	0.151						
0.52	1.45	6.68	0.130	1.90	0.068	0.588	0.412	0.302	6.69
0.53	1.75	8.07	0.110						
0.54	2.13	9.82	0.092	1.70	0.054	0.594	0.406	0.312	9.87
0.55	2.70	12.45	0.074						
0.56	3.40	15.67	0.060	1.40	0.043	0.603	0.397	0.327	15.67
0.57	4.50	20.74	0.046						
0.58	6.0	27.66	0.035	1.0	0.035	0.615	0.385	0.347	27.66
0.59	8.0	36.88	0.026						
0.60	11.3	52.09	0.019	0.6	0.032	0.632	0.368	0.376	51.63
0.61	18.0	82.98	0.012						
0.62	32.5	149.8	0.007	0.45	0.016	0.636	0.364	0.383	141.86
0.63	70.0	322.7	0.003						
0.64	150.0	691.5	0.001						

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 Oil Cut (1/1 + WOR)	Stock Tank WOR ( $\sqrt{2} \times$ WOR)
0.88	.235	.319	.848	.064	.521	0.92
0.90	.236	.322	.850	.065	.513	0.95
1.0	.239	.340	.855	.069	.488	1.05
1.5	.252	.418	.880	.093	.388	1.58
1.71	.256	.440	.889	.100	.357	1.80
2.0	.262	.470	.898	.111	.323	2.10
2.5	.269	.510	.912	.125	.275	2.63
3.0	.275	.540	.923	.137	.241	3.15
4.0	.285	.590	.940	.158	.192	4.20
5.0	.292	.628	.955	.175	.160	5.25
6.0	.298	.654	.965	.188	.137	6.30
7.0	.303	.676	.975	.200	.120	7.35
8.0	.307	.695	.983	.210	.106	8.40
9.0	.311	.710	.990	.219	.096	9.45
10.0	.314	.724	.997	.227	.087	10.50
10.3	.320	.730	1.000	.234	.085	10.82
15.0	.327	.778	1.000	.254	.060	15.75
20.0	.337	.805	1.000	.271	.045	21.00
30.0	.350	.850	1.000	.298	.031	31.50
40.0	.359	.872	1.000	.313	.023	42.00
50.0	.366	.890	1.000	.326	.019	52.50

TABLE V

NORTH VIRDEN SCALLION FIELD

PREDICTION OF FLOOD BEHAVIOR AFTER BREAKTHROUGH

$N^1 = 153,110,000$  bbl.

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
<u>Oil</u> <u>Cut</u>	<u>W.F.</u> <u>Rec.</u> <u>R</u>	<u>Oil</u> <u>Rate</u> <u>BOPD</u>	<u>Avg.</u> <u>BOPD</u>	<u>Cum. Oil</u> <u>Prod.</u> <u>(bbl.)</u>	<u>Incr. of</u> <u>Oil Prod.</u> <u>(bbl.)</u>	<u>Incr. of</u> <u>Time</u> <u>(day)</u>	<u>Cum.</u> <u>Time</u> <u>(day)</u>	<u>Cum.</u> <u>Time</u> <u>(yr.)</u>
0.357 BT	0.10	3,640		15,310,000			0	0
0.300	0.118	3,060	3,350	18,070,000	2,760,000	824	824	2.25
0.250	0.135	2,550	2,805	20,670,000	2,600,000	927	1,751	4.79
0.200	0.154	2,040	2,295	23,580,000	2,910,000	1,268	3,019	8.27
0.170	0.170	1,735	1,890	26,010,000	2,430,000	1,286	4,305	11.79