## ABSTRACT

Often in petroleum reservoir analysis it is necessary to
measure the electrical resistivity of the water present in a
formation.  Formation water salinity and fluid saturations can
both be calculated from the water resistivity and well log data.

Since the first production from the Bryan Woodbine Field,
only dry oil has been produced.  However, it may be possible to
determine the water resistivity by saturating core samples with
water of various salinities and recording the formation resistivity
of the sample.  Plotting the formation resistivity data versus
the depth of each sample should yield a curve which can be cor-
related with the actual resistivity log to determine the correct
water resistivity.

In addition to determining the water resistivity, information
on the effect of solution gas on oil resistivity should be obtained.

## DISCUSSION

Knowing the formation water resistivity is extremely useful for calculating fluid saturations using only well logs. The formation water resistivity could possibly be determined using an iterative laboratory procedure. Cores from selected wells will be saturated with water of known salinity (resistivity). Using standard core laboratory techniques, the porosity and water saturation can be determined. Then, using a transducer, the resistivity of the saturated core plug will be measured. This process will be repeated for other reasonable fluid saturations. (It is logical to assume that the water saturation is near minimum interstitial). Then the core resistivities will be measured for a different water salinity. Data will be collected for salinities between 10,000 and 12,000 PPM. The entire process is repeated for another core sample at a different depth interval so that a curve of formation resistivity vs. depth can be developed. This curve will be compared to the log to determine the true water resistivities. This exhaustive amount of laboratory work will require more than one person so I will be working with a partner. However, the Theses will be written independently and on slightly different aspects or conclusions of the research. We hope to answer the following questions?

1) Can water resistivity of a volumetric reservoir be determined without a water sample?

2) What effect does solution gas have on formation resistivity?

DISCUSSION
cont.


3)  What type of averaging method is best to correlate

logs with core analysis?


If RW can be determined for reservoirs which are not

producing water, then there could be numerous applications

of this technique to newly drilled fields.

# AN ITERATIVE LABORATORY
## METHOD FOR THE DETERMINATION OF WATER RESISTIVITY

By

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Petroleum Engineering

Submitted in partial fulfillment of the requirements
of the University Undergraduate Fellows Program.

Approved by:

R. Heins

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# AN ITERATIVE LABORATORY METHOD
## FOR THE DETERMINATION OF WATER RESISTIVITY
## IN SHALY FORMATIONS

Jon Thomas Givens, SPE Student Member

## ABSTRACT

This paper presents the results of an extensive laboratory investigation of the saturation relationships of shaly formations. A new laboratory method for determining formations water resistivity and thus water saturation is presented. The effects of shale on the parameters of the traditional water saturation-resistivity equation are discussed. Finally, an argument against using the traditional water saturation-resistivity equation in shaly formations is presented, and an alternate equation is suggested.

## INTRODUCTION

The core samples were obtained from the Bryan Field, which consists of an Upper Cretaceous Stratigraphic Woodbine sandstone. This field is located in Brazos County, Texas. Fifty-two core plugs were cut parallel to bedding from whole cores from the Trant No. 1, Phillips No. 1, and Harper No. 1 wells. The locations and depths of these wells are indicated on the contour map (Figure 1).

This research was begun to find another method for determining water resistivity in shaly formations which do not produce water. The easiest method for determining water resistivity is to directly measure produced water; however this cannot be done for volumetric reservoirs. Water resistivity can be determined from the SP log; however, the SP log is

greatly effected by the presence of shale. Morris Method is designed for shaly formations, but it requires both neutron and density logs. This method did not work well in the Bryan Field. Another method is to assume a water resistivity from a nearby formation. The Bryan Field was evaluated using the water resistivity of the Kurten Field of .064$\Omega$-m at 250°F. Clearly, there is a need for a scientific method to determine the water resistivity in shaly volumetric reservoirs.

An accurate value of water resistivity is necessary to determine water saturation from well logs. Figure 2 shows the effect of water saturation on values of original oil in place calculated using the material balance equation for an undersaturated volumetric reservoir.

## GEOLOGIC SETTING

The Bryan Field Woodbine sand is believed to have been deposited in a deep marine turbidite. The Kurten Field is believed by Bell to be a deltaic deposit. This is consistent with its position to the north of the Bryan Field since both formations are Cretaceous deposits. The geologic environment of the Bryan Field suggests it should have a higher salinity and lower water resistivity than the Kurten Field. This conclusion is consistent with the results of this paper.

## LABORATORY METHOD

The objective of this method is to reproduce the water saturation and salinity of the formation in the laboratory. Core samples will be saturated

with different salinities of water until the well log response is matched. The corresponding salinity should be the formation salinity. The unknown values are water saturation, water resistivity, and saturation exponent. By fixing the water satuation as the minimum irreducible water saturation, then the salinity may be used to iterate until the water resistivity and saturation exponent produce the well log response.

The laboratory procedure is:

1.  Cut core plugs and extract cores using toluene in the USBM Distillation Apparatus.
2.  Oven dry cores and record dry weight.
3.  Measure core diameter and length with caliper to .001 inch.
4.  Saturate core 100% with saline water.
5.  Weigh core and measure $R_o$.
6.  Centrifuge cores at 2300 RPM for 10, 30, 60, 90, 120 minutes at each time weigh core and measure resistivity.
7.  Plot log $\frac{Rt}{Ro}$ Vs Sw and determine the slope n.
8.  Convert the resistivity values to reservoir temperature using:

$$R_{t_{res}} = \frac{R_o)}{R_{w\ lab}} \quad \frac{R_{wres}}{S_w^{\ n}}$$

9.  Correlate log and core depths.
10. Plot RILD Vs Depth and $R_{t_{res}}$ Vs Depth on the same plot.

11. If $R_{t_{res}}$ is greater than RILD then increase salinity. If $R_{t_{res}}$ is less than RILD then decrease salinity.

12. Displace the old solution with the newly chosen solution and repeat the procedure from Step 4 to 12.

The deep induction is the best log response to match. If the mud fitrate is known a more complex procedure could be used to match the shallow or medium induction log. The weight of the core is used to determine the water saturation. An air-water system is used in this procedure to model an oil-water system. The core could be reduced to minimum irreducible water saturation with oil, and use an oil-water system but this takes more time. It also requires additional extractions of the core. For the purpose of resistivity measurements air simulates oil very well.

## RESULTS

The first salinity chosen was 28000 ppm. The salinity should start at the lowest value and be increased in this procedure to minimize the affect of residual salts. The resulting values of resistivity for each depth are presented in Figure 3 and Table 1. The values of resistivity at this water salinity are much larger than the well log values. The water saturation would have to be larger than 100% in some parts of the interval to match the well log response. While this salinity is lower than the 32,000 ppm of the Kurten Field it is obvious that the Kurten Field salinity is lower than that of the Bryan Field.

The salinity was then increased to 57,000 ppm.  The resulting values of resistivity for each depth are contained in Table 1 and Figure 3.  These values produce an accurate RILD response.  Figure 3 suggests the actual salinity may be slightly higher than 57,000 ppm.

The next step is to test the 57,000 ppm salinity in another well.  This is a recommended procedure to verify the salinity.  Figure 4 and Table 2 show the results of saturating the Phillips No. 1 well with 57,000 ppm water.  The good match indicates that residual salts are not a problem.  Figures 3 and 4 indicate that this procedure is a success.

## PROCEDURAL DRAWBACKS

Even though the laboratory method produced excellent results, there are several drawbacks and potential sources of error.  The two main drawbacks are high cost and time.  This procedure requires lengthy and costly special core analysis, and should only be used if there is a significant doubt about the water saturation.

Aged cores were used in this analysis, so care was taken to assure that the wettability was not altered.  The samples on the edge of a formation may not be matched by the log response. This is due to transitional and thin bed affects.  In the Bryan Field samples it was difficult to establish the minimum irreducible water saturation.  Due to evaporation and high permeability it was possible to reduce the cores below the irreducible water saturation at a centrifuge speed of only 2300 RPM.  A time of 10 to 30

minutes was usually considered the time necessary to achieve the desired saturation. This problem will probably not be encountered in other fields, however, due to lower permeability other samples will require a longer time to reach minimum water saturation.

## AFFECT OF SHALE ON PARAMETERS

The values of shale fraction were determined from the well logs for each sample depth. The neutron-density cross plot for the three wells is shown in Figure 5. Figures 6 and 7 indicate that as shale content increases the saturation exponent decreases. Comparing these figures shows that the saturation exponent also varies with salinity. This is the reason the procedure must be iterative, because both water resistivity and saturation exponent vary with salinity.

The most interesting relationship studied was that of the resistivity of the core 100% saturated with saline water ($R_o$) and shale fraction. The results for $R_o$ are identical to those for formation factor by definition. Figures 8, 9, and 10 demonstrate that as shale fraction is increased resistivity is increased. This is exactly opposite of the expected result. The "resistivity paradox" is explained by the affect of shale fraction on porosity as seen in Figure 11. The higher the shale fraction the lower the porosity.

The presence of shale creates a parallel circuit configuration. A clean sandstone sample is analogous to a series circuit. The higher the shale fraction the more parallel elements are created and the lower the resistivity. This is true for a constant porosity sample.

When a core has a high porosity it contains many electrical flow paths and thus a low resistivity. The lower the porosity, the fewer the electrical flow paths and the higher the resistivity.

Thus, even though as shale fraction increases which causes clay resistivity to decrease; the porosity decreases which cause the resistivity to increase. The affect of porosity can be greater on resistivity in shaly sands than the affect of the shale itself.

If shale fraction and resistivity are high and the porosity is low the shale is occupying pore space. If the shale fraction is high and the resistivity is low and the porosity is high then the shale is dispersed in the matrix. Thus, plots of $R_o$, porosity, and shale fraction can be used to determine the presence and type of shale. This is important in well log analysis, geologic modelling, and computer simulation. An approximate equation relating the factors, which is accurate in low shale fraction ranges for 57,000 ppm water is:

$$R_o = 1/2 \left[ .1117088(V_{sh}) - 1.27596 (\phi) + 26.884434 \right]$$

where $V_{sh}$ and $\phi$ are per cents.

Figure 12 shows the relationship between porosity and $R_o$. This relation demonstrated an equally good fit for linear, exponential, or hyperbolic equations. The "resistivity paradox" is clearly caused by porosity.

## GOVERNING THEORETICAL EQUATIONS

The traditional water saturation-resistivity equation was derived for nonshaly formations. When shale is present there is a bend in the plot. In the majority of the cases in this study the bend was actually better characterized by an exponential fit. The traditional equation and the new equation are presented below.

**TRADITIONAL EQUATION**

$$S_w^n = \frac{R_o}{R_t}$$



**SHALY EQUATION**

$$S_w^{n'} = \frac{aR_o}{R_t}$$
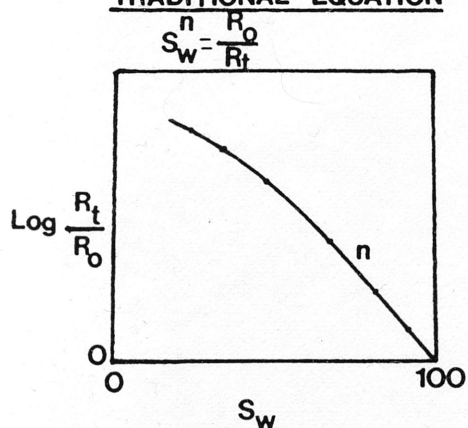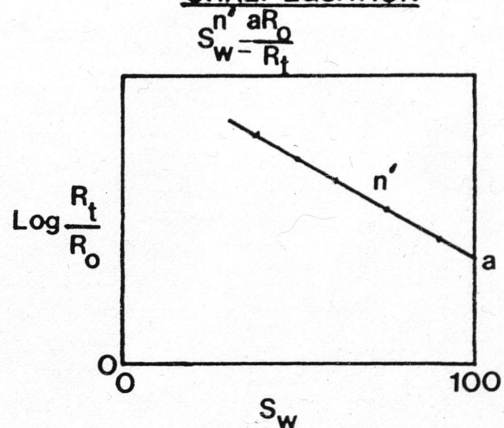


The new equation is more accurate than the traditional equation for shaly sands. This equation is restricted to water saturations from 0 to 35 percent. At 100 percent water satuation the equation is obviously invalid since log $R_t/R_o$ does not equal zero. However, in the practical water saturation range the new equation is a better physical model for shaly sands. The new equation with average constants is:

$$S_w^{1.6489} = \frac{2.06678 \, R_o}{R_t}$$

## CONCLUSIONS

1.  At high water saturations an exponential relationship exists because the electron flow path is continuous. As water saturation decreased in a shaly sample the electron flow path becomes a parallel configuration of discontinuous water elements and clay particles.

2.  In the laboratory procedure an air-water system can be used to model an oil-water system.

3.  Resistivity in shaly formations is a function of porosity, water saturation, water salinity, wettability, tortuosity, and shale fraction.

4.  Porosity can have a larger influence on resistivity than the shale fraction in shaly formations.

5.  The type and position of shale can be determined from graphs of porosity, core resistivity 100 per cent saturated with formation water, and shale fraction.

6.  Laboratory resistivity values matched the deep induction log readings and not the focused or medium induction log readings.

7.  Although the new method is time consuming and costly, it produces good reproducible results.

8.  Saturation exponent is a function of shale fraction and salinity.

FIGURE 1
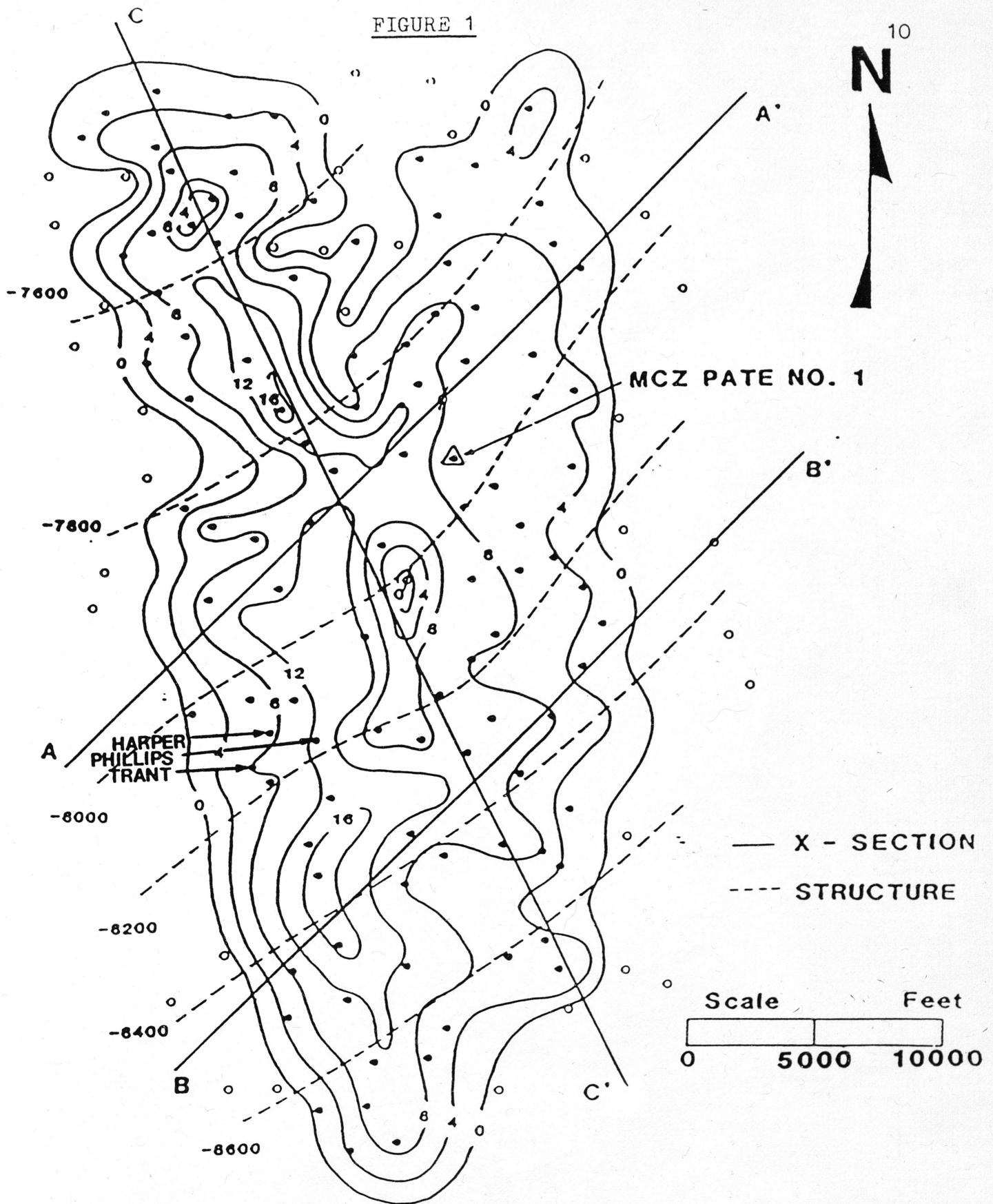
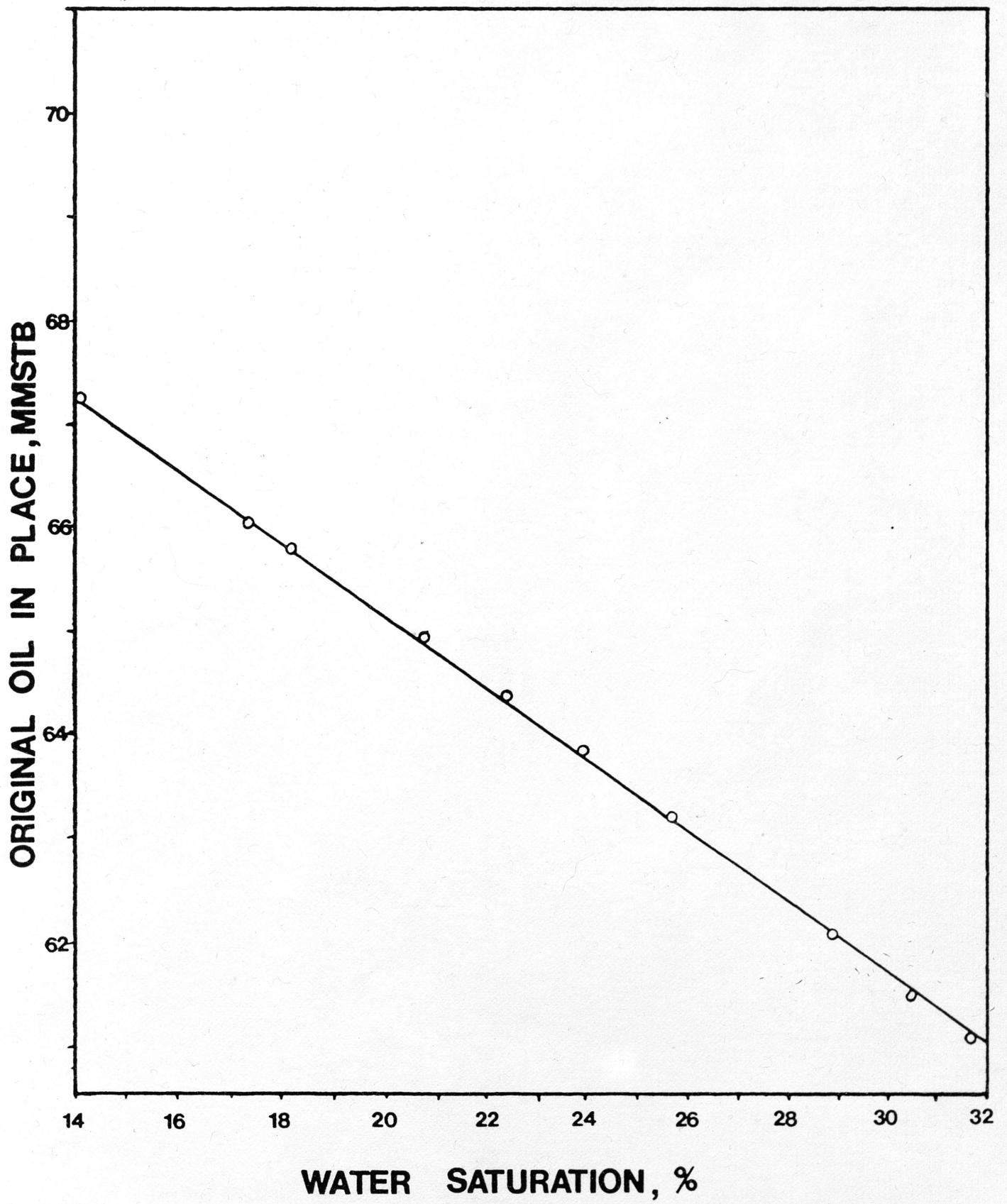NET SAND ISOPACHOUS

AND STRUCTURE MAP
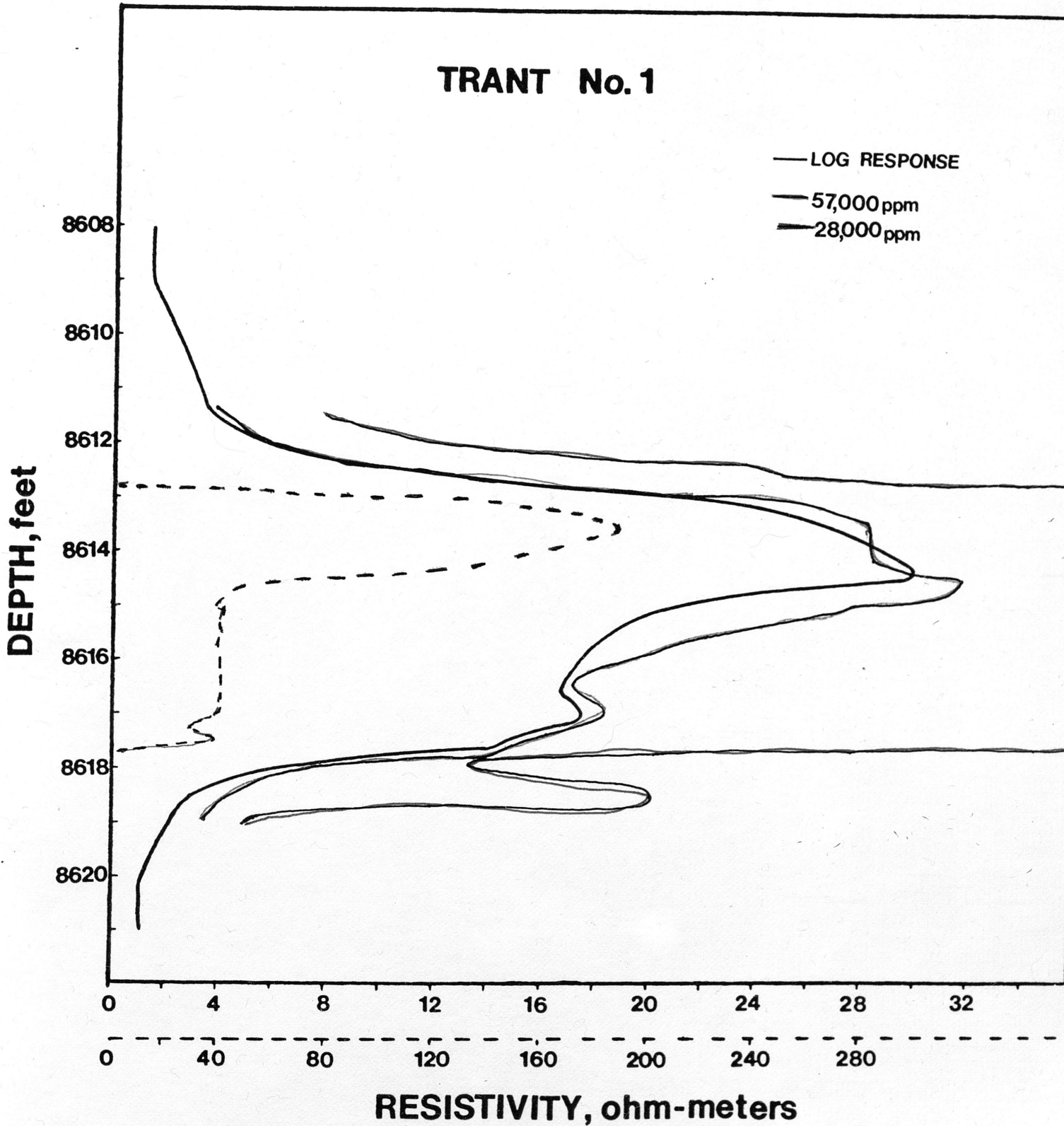
FIGURE 2

FIGURE 3



TRANT No. 1

## TABLE 1

## Resistivity Comparison For Trant No. 1

| Depth, ft. | $S_w$, % | $R_t$ log, $\Omega$-m | $R_t$ 28000 ppm, $\Omega$-m | $R_t$ 57000 ppm, $\Omega$-m |
|---|---|---|---|---|
| 8611.5 | 64 | 3.75 | 6.53 | 4.06 |
| 8611.5 | 75 | 3.75 | 8.04 | 5.05 |
| 8612 | 40 | 5.3 | 12.51 | 5.76 |
| 8612.5 | 25.5 | 11.9 | 23.53 | 11.85 |
| 8613 | 19 | 22.5 | 64.43 | 22.5 |
| 8613.5 | 16 | 27 | 188.89 | 28.49 |
| 8614.3 | 16 | 30 | 117.41 | 28.65 |
| 8614.5 | 22.8 | 28.8 | 63.46 | 32.1 |
| 8615 | 25.5 | 20.7 | 44.42 | 27.7 |
| 8615.5 | 27 | 18.4 | 42.39 | 23.5 |
| 8616.5 | 22 | 16.7 | 40.98 | 17.25 |
| 8617 | 33 | 17.5 | 41.41 | 18.42 |
| 8617.3 | 40 | 15.5 | 31.07 | 16.2 |
| 8617.5 | 40 | 14.5 | 39.89 | 15.54 |
| 8618 | 50 | 5.68 | 13.36 | 6.86 |
| 8618.5 | 75 | 2.81 | 20.39 | 10.19 |
| 8619 | 73 | 2.1 | 5.44 | 3.5 |

FIGURE 4

14



PHILLIPS No. 1

LOG RESPONSE
57,000 ppm

DEPTH, feet

RESISTIVITY, ohm-meters
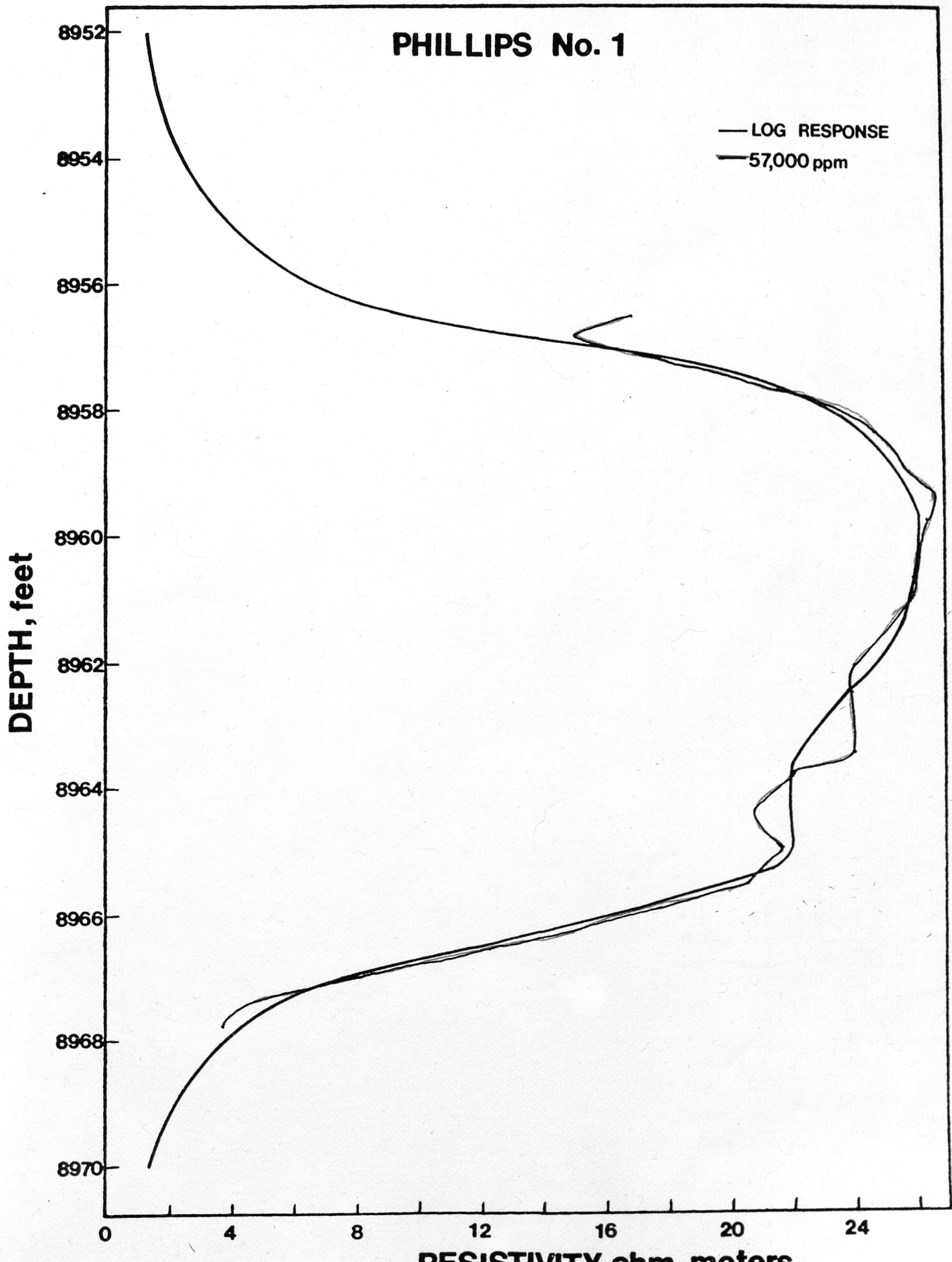
## TABLE 2

## Resistivity Comparison For Phillips No. 1

| Depth, ft | $S_w$, % | $R_t$ log, $\Omega$-m | $R_t$ 57000 ppm, $\Omega$-m |
|---|---|---|---|
| 8956.4 | 60 | 9 | 16.91 |
| 8956.9 | 40 | 14 | 14.77 |
| 8957.5 | 46 | 20.6 | 20.22 |
| 8958.5 | 25 | 24.7 | 25.2 |
| 8958.7 | 17.5 | 25 | 25.3 |
| 8959.3 | 25.5 | 26. | 26.6 |
| 8959.7 | 18.5 | 26.2 | 26.34 |
| 8960.4 | 17 | 26.1 | 26.1 |
| 8961 | 16 | 25.9 | 25.99 |
| 8961.5 | 14.5 | 25.7 | 24.97 |
| 8962.1 | 23 | 24.8 | 23.93 |
| 8962.5 | 23 | 24 | 24.02 |
| 8963.4 | 24 | 22.4 | 24.09 |
| 8963.7 | 25 | 22.1 | 21.92 |
| 8964.3 | 30 | 22 | 20.75 |
| 8964.9 | 23 | 22.1 | 21.78 |
| 8965.4 | 16 | 21 | 21.12 |
| 8966.1 | 34.9 | 16 | 16.71 |
| 8967 | 50 | 7.7 | 7.24 |
| 8967.4 | 50 | 5.5 | 4.36 |
| 8967.7 | 50 | 4.3 | 3.77 |

FIGURE 5



$\emptyset_n$-$\emptyset_d$ CROSSPLOT

FIGURE 6

FIGURE 7

57,000ppm

$$n = -.9573(V_{sh}) + 2.218$$

r = .59

FIGURE 8



28,000 ppm

$$R_O = .1567 (V_{sh}) + 6.209$$

r = .836

FIGURE 9



57,000 ppm

$$R_O = .1117 (V_{sh}) + 2.089$$

r = .85

$R_O$, ohm-meters

$V_{sh}$, %

FIGURE 10



57,000 ppm

$$R_O = .3046(V_{sh}) + 1.881$$

r = .86

$R_O$, ohm-meters

$V_{sh}$, %

FIGURE 11



$$\varnothing = -.109 \, (V_{sh}) + 17.995$$

$r = .903$

FIGURE 12

57,000 ppm

$$R_O = {}^-1.276\,(\emptyset) + 24.796$$

r = .93

O $(\emptyset, R_O)_{V_{sh}max}$

$R_O$, ohm-meters

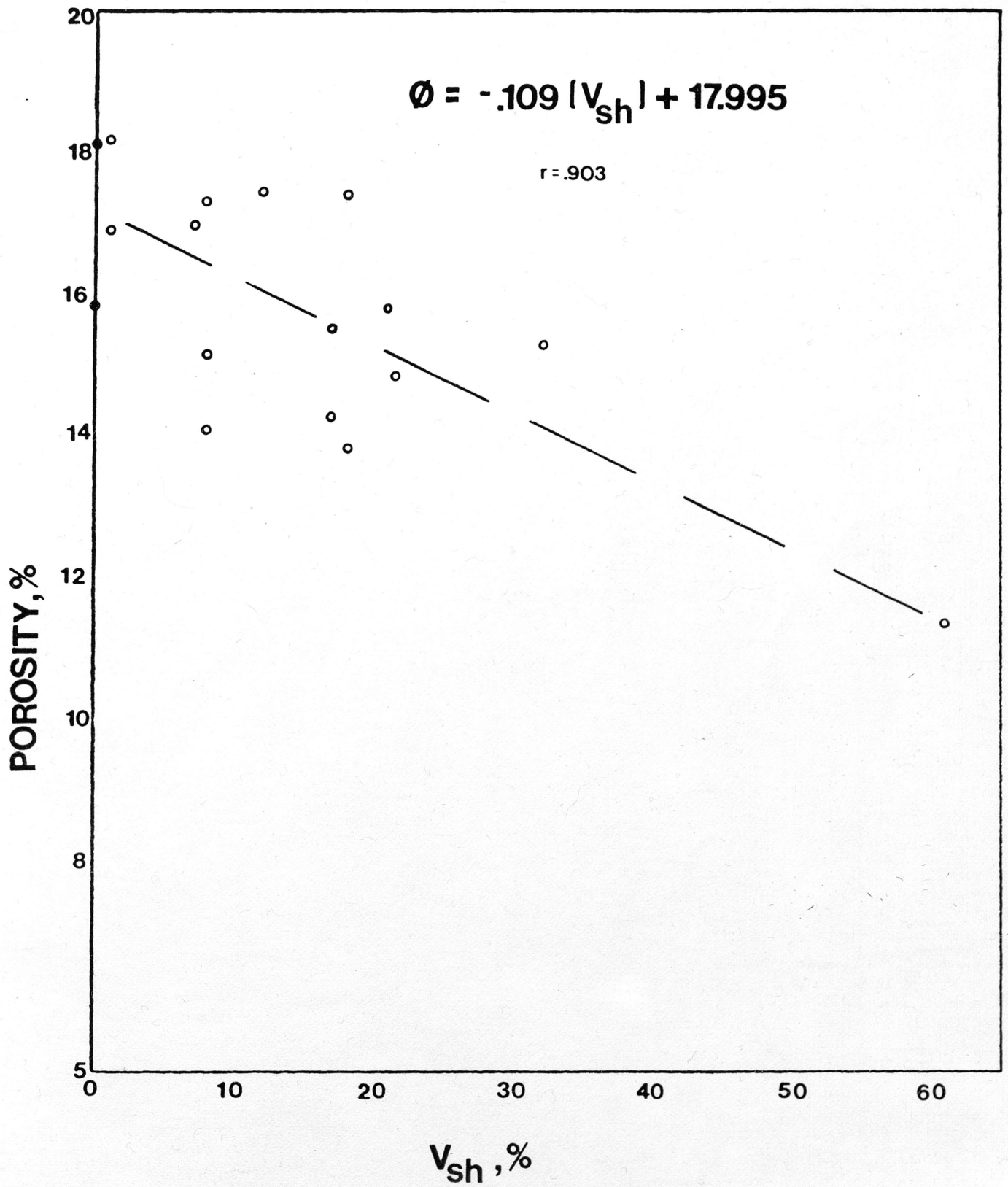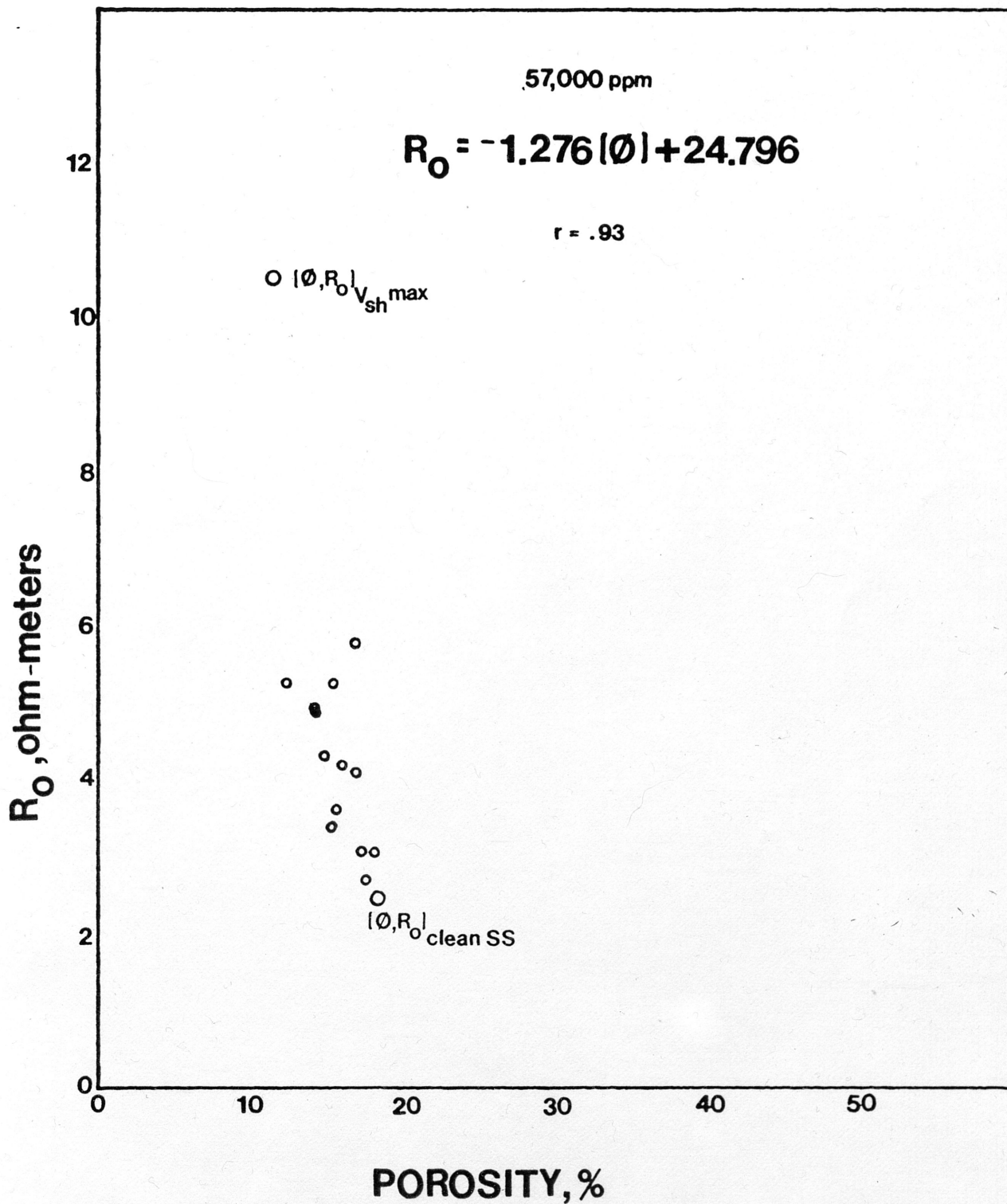$(\emptyset, R_O)_{clean\,SS}$
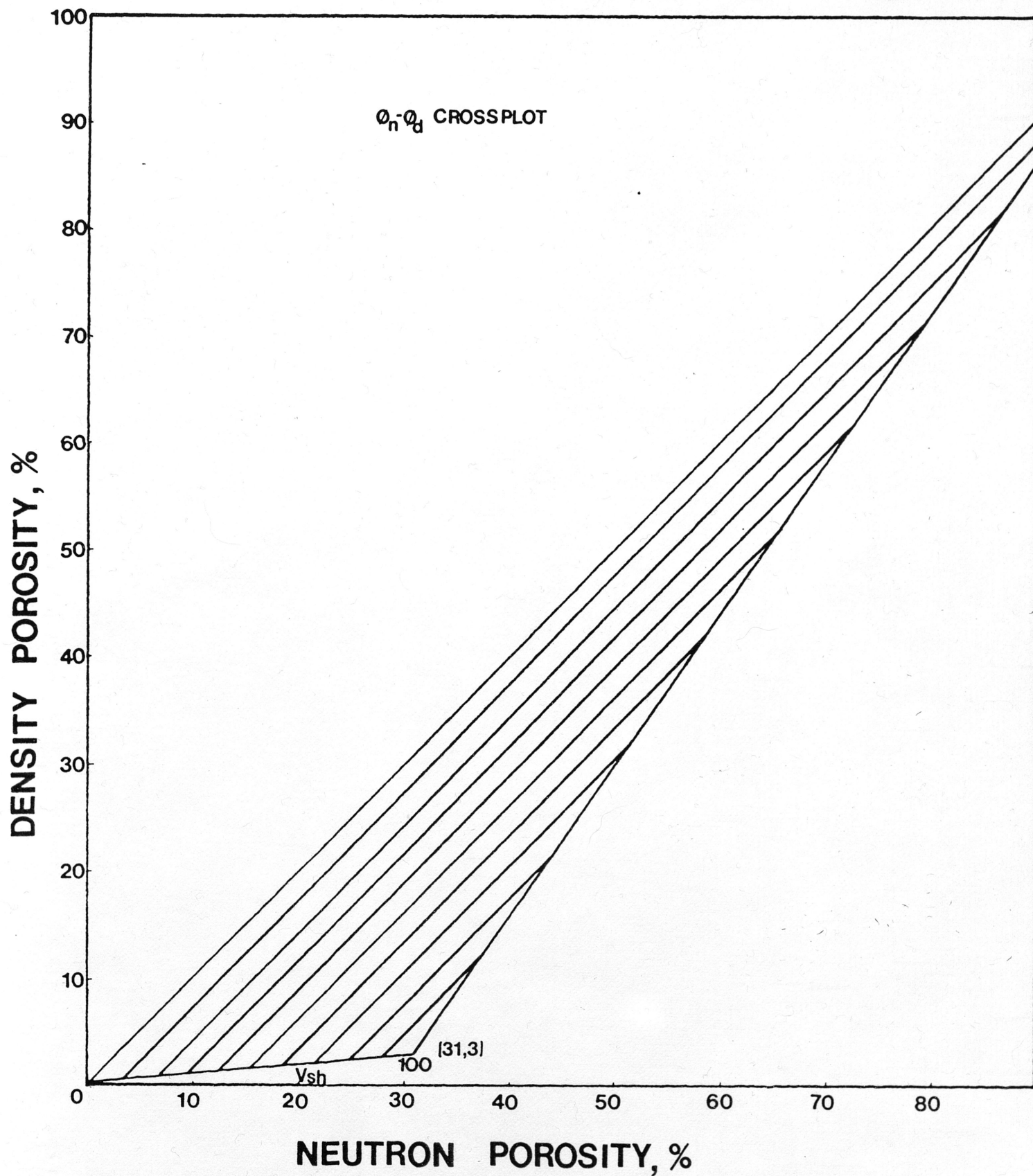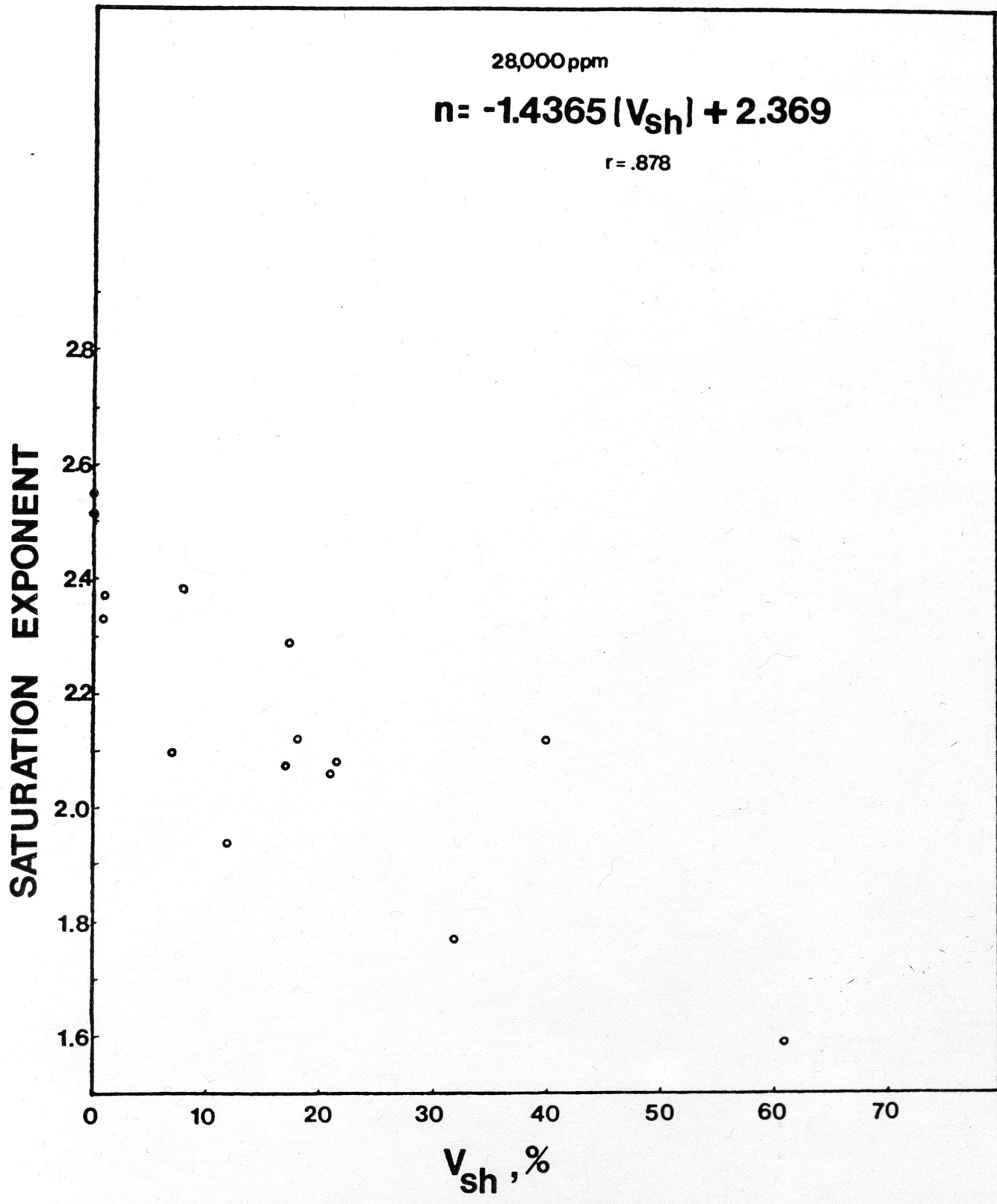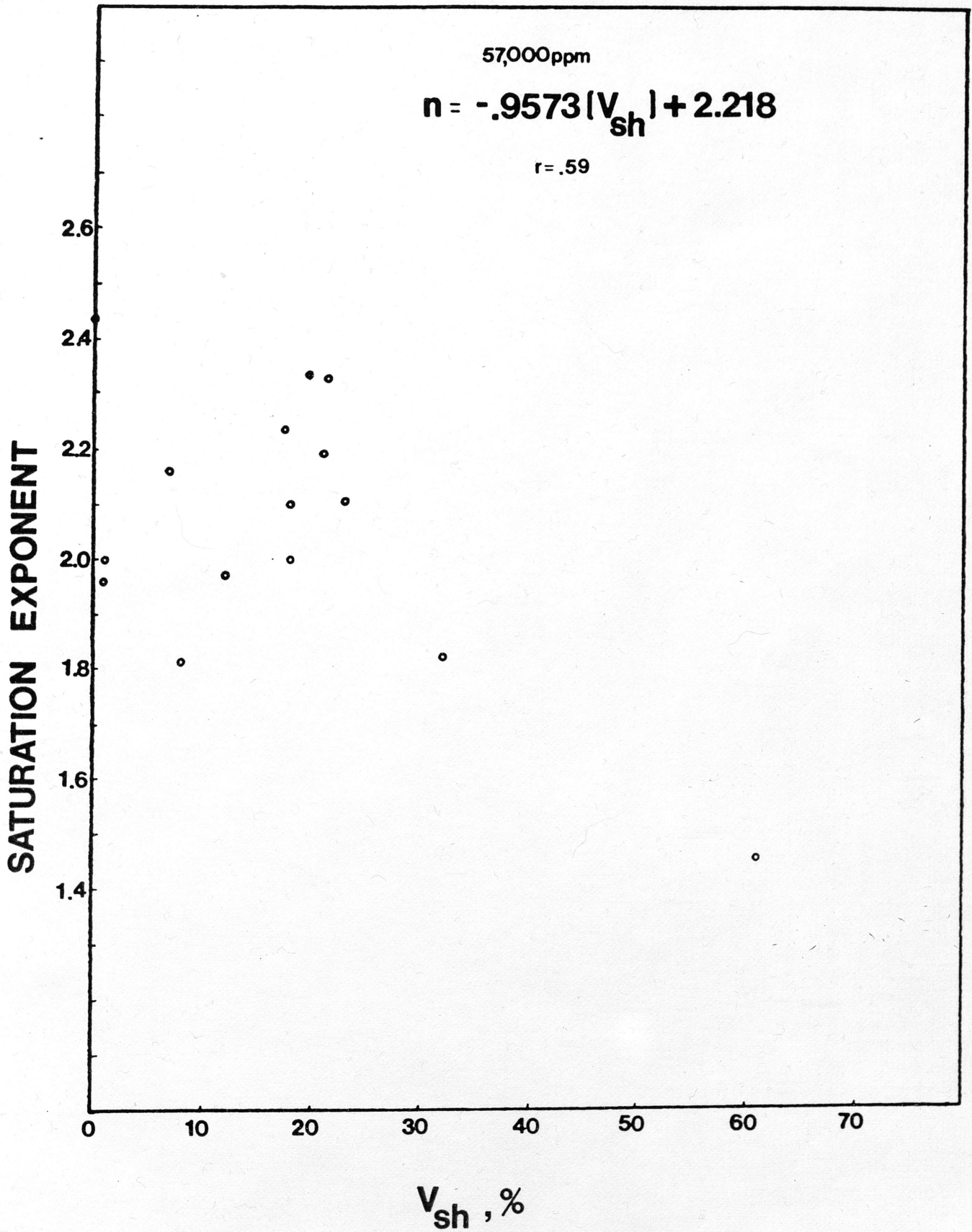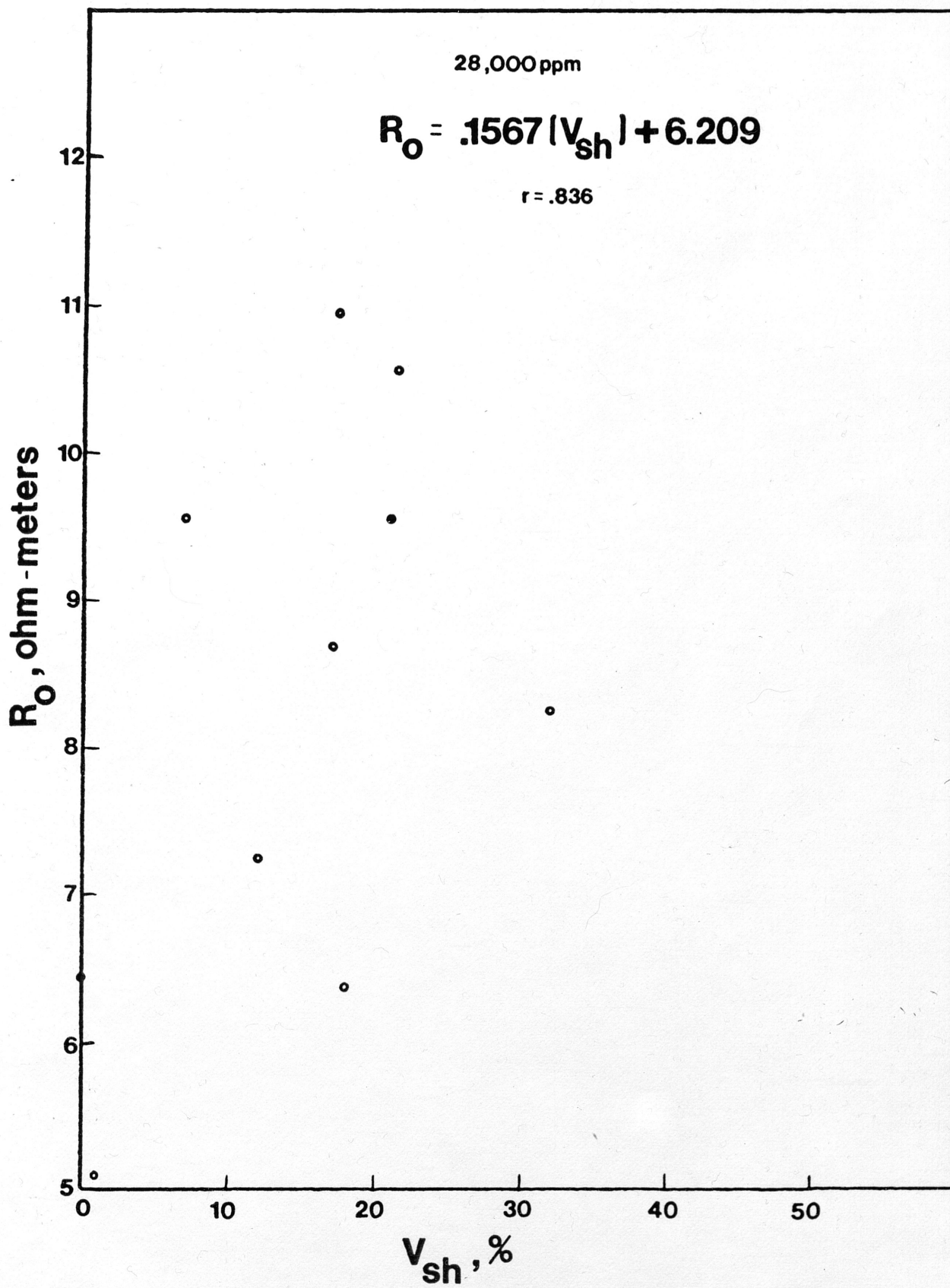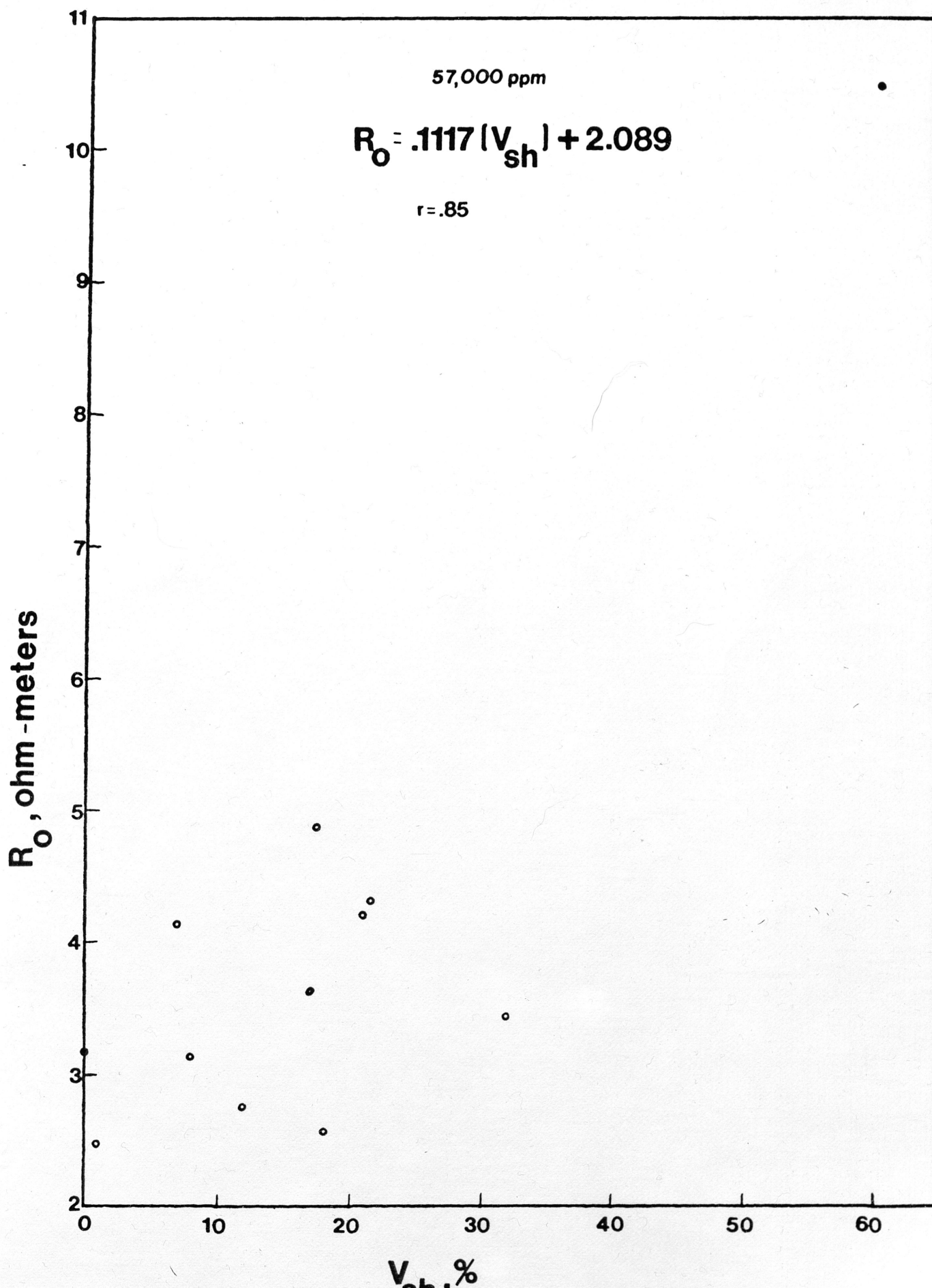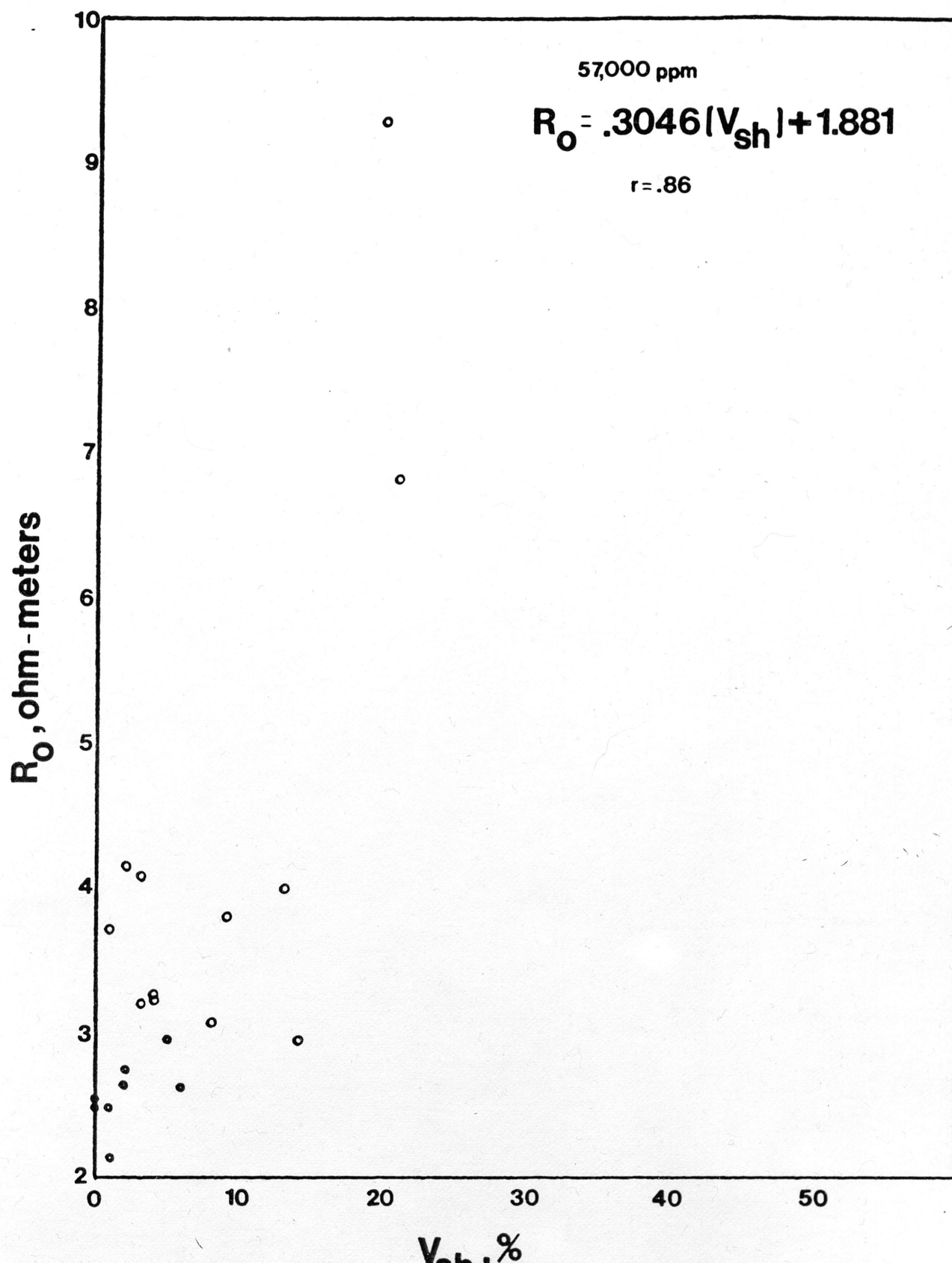
POROSITY, %

# NOMENCLATURE

$a$ = Constant in shale saturation equation

$F$ = Formation Factor

$n$ = Saturation exponent

$n'$= Saturation Exponent in shale equation

$\emptyset$ = Porosity,%

$R_o$= Resistivity of core 100 % saturated with formation water,$\Omega$-m

$R_{t\ res}$= Resistivity of formation at its saturation and temperature,$\Omega$-m

$R_w$= Formation water resistivity at laboratory temperature,$\Omega$-m

$R_{w\ res}$= Formation water resistivity at reservoir temperature,$\Omega$-m

$S_w$= water saturation,%

$V_{sh}$= Shale fraction,%

## ACKNOWLEDGMENTS

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