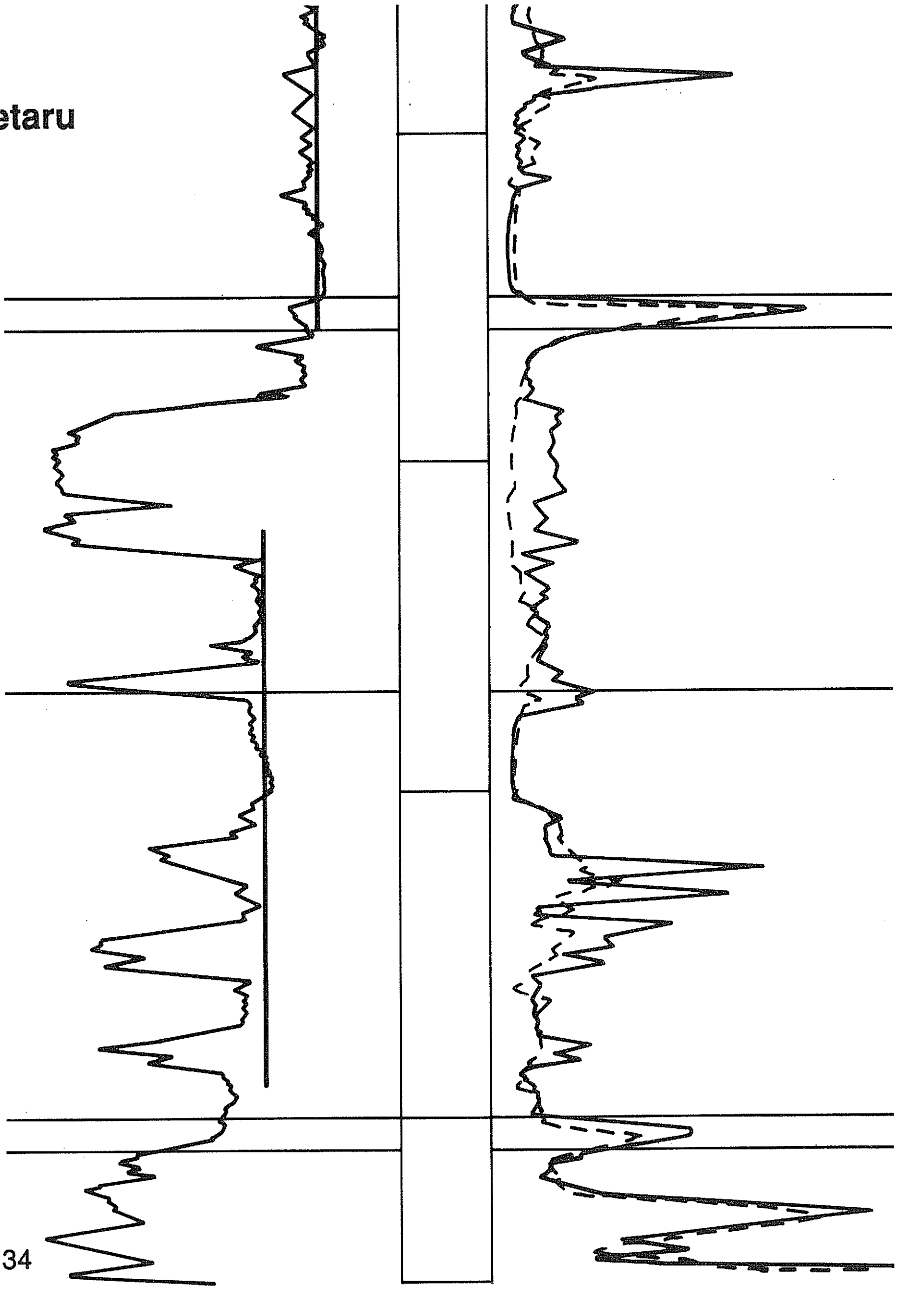
APPLICATION OF OLD ELECTRIC LOGS IN THE ANALYSIS OF AUX VASES SANDSTONE (MISSISSIPPIAN) RESERVOIRS IN ILLINOIS

Hannes E. Leetaru



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ILLINOIS STATE GEOLOGICAL SURVEY
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ABBREVIATIONS

F	formation factor
m	cementation exponent
n	number of wells
NSP	normalized spontaneous potential
ϕ	porosity of the formation
r	Pearson correlation coefficient
R_a	apparent resistivity of the formation
R_i	resistivity of the invaded zone
R_m	resistivity of the mud
R_{mf}	resistivity of the mud filtrate
R_o	resistivity of the formation 100 percent saturated with formation water
R_t	resistivity of the formation
R_w	resistivity of the formation water
SP	spontaneous potential
$\mathrm{SP}_{\mathrm{log}}$	SP measurement from zone of interest
$\mathrm{SP}_{\mathrm{min}}$	average SP at the shale baseline
$\mathrm{SP}_{\mathrm{max}}$	average SP for a clean sandstone
S_w	water saturation

ACKNOWLEDGMENTS

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ABSTRACT

Old electric logs (pre-1960) are a valuable source of information for the oil industry to use for improved and enhanced oil recovery. In this study, old electric logs were used effectively to estimate porosity and water saturation. The empirical methods described in this report are quick and easy to use. Results of the analysis can be applied to identifying passed-over pay in older wells and as input into reservoir models.

Three methods for using old electric logs to estimate the porosity of the Aux Vases Sandstone (Mississippian) were tested for wells in Jefferson, Wayne, Franklin, and Hamilton Counties in Illinois. The empirical normalized spontaneous potential method was significantly better at predicting porosity than were the short normal or Rocky Mountain methods.

Normalizing spontaneous potential values against an internal standard can compensate for changes in the scale of the log, the mud resistivity, and the size of the borehole and allow direct comparisons of spontaneous potential values between different drill holes. The clean sandstones within the Cypress Formation, which occur about 200 feet above the Aux Vases, were used in this investigation to normalize (or standardize) the spontaneous potential.

Although on a regional scale values for permeability from the normalized spontaneous potential are commonly in the correct order of magnitude, they are not considered accurate enough to use in reservoir analysis. However, in local areas with similar diagenetic and depositional facies, the correlation can be strong enough to allow for semiquantitative predictions of permeability. Pickett plot analysis is a viable alternative to the Archie equation in estimating water saturation in the Aux Vases. The major advantage of Pickett plot analysis is that neither the cementation exponent nor the resistivity of the formation water has to be known to calculate water saturation.

INTRODUCTION

Techniques are presented for using old (generally pre-1960) electric logs to characterize hydrocarbon reservoirs of the Upper Valmeyeran (Mississippian) Aux Vases Sandstone (fig. 1). Since many of the Aux Vases oil fields were discovered before 1960, an understanding of old electric logs is important for detailed reservoir analysis. The better Aux Vases oil fields were discovered between 1938 and 1955 and have produced more than 1 million barrels of oil. Logging tools for measuring porosity were rarely used. For example, in a typical field such as King Field, Jefferson County, Illinois, less than five neutron or micrologs were run out of the 163 wells drilled. One suite of modern logs was run, but this well did not represent the reservoir facies.

The study area includes Franklin, Hamilton, Jefferson, and Wayne Counties (fig. 2). It lies in the southern part of the Illinois Basin and is bounded on the west, south, and southeast by the Du Quoin Monocline, the Cottage Grove Fault System, and the Wabash Valley Fault System (fig. 3). The Aux Vases in the study area is 2,000 to 3,000 feet deep.

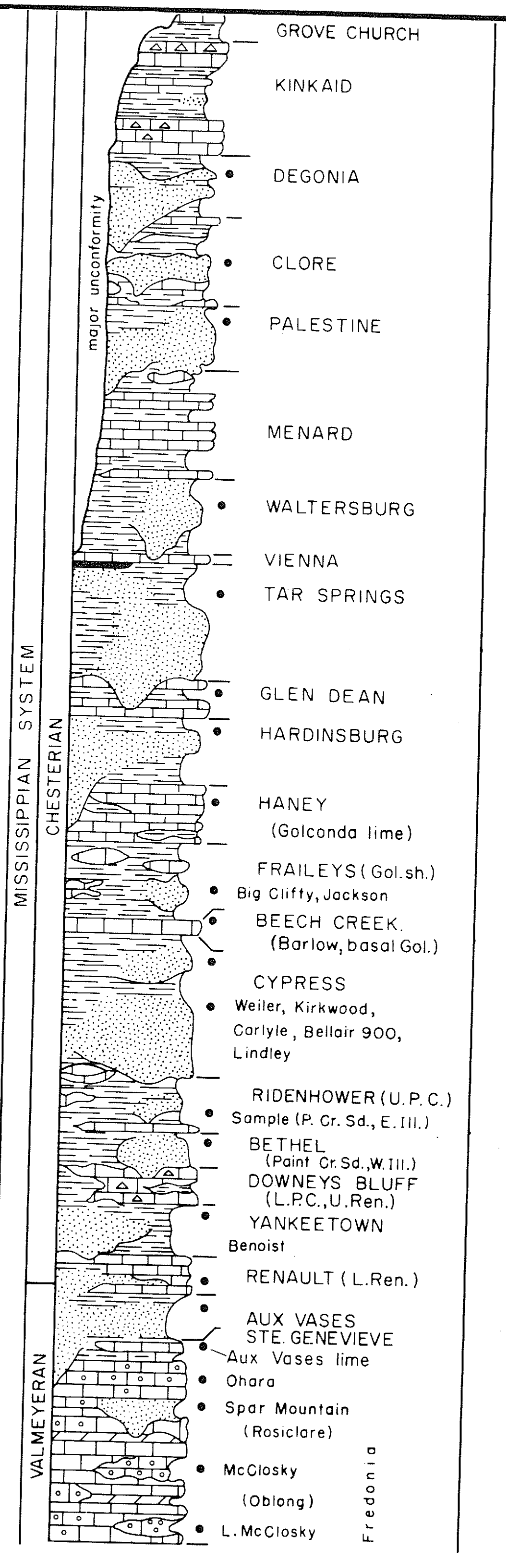

Figure 1 Generalized upper Valmeyeran and Chesterian geologic column of southern Illinois (modified from fig. 3, prepared by David Swann, from Bell et al. 1961). Bullets indicate oil-producing intervals.

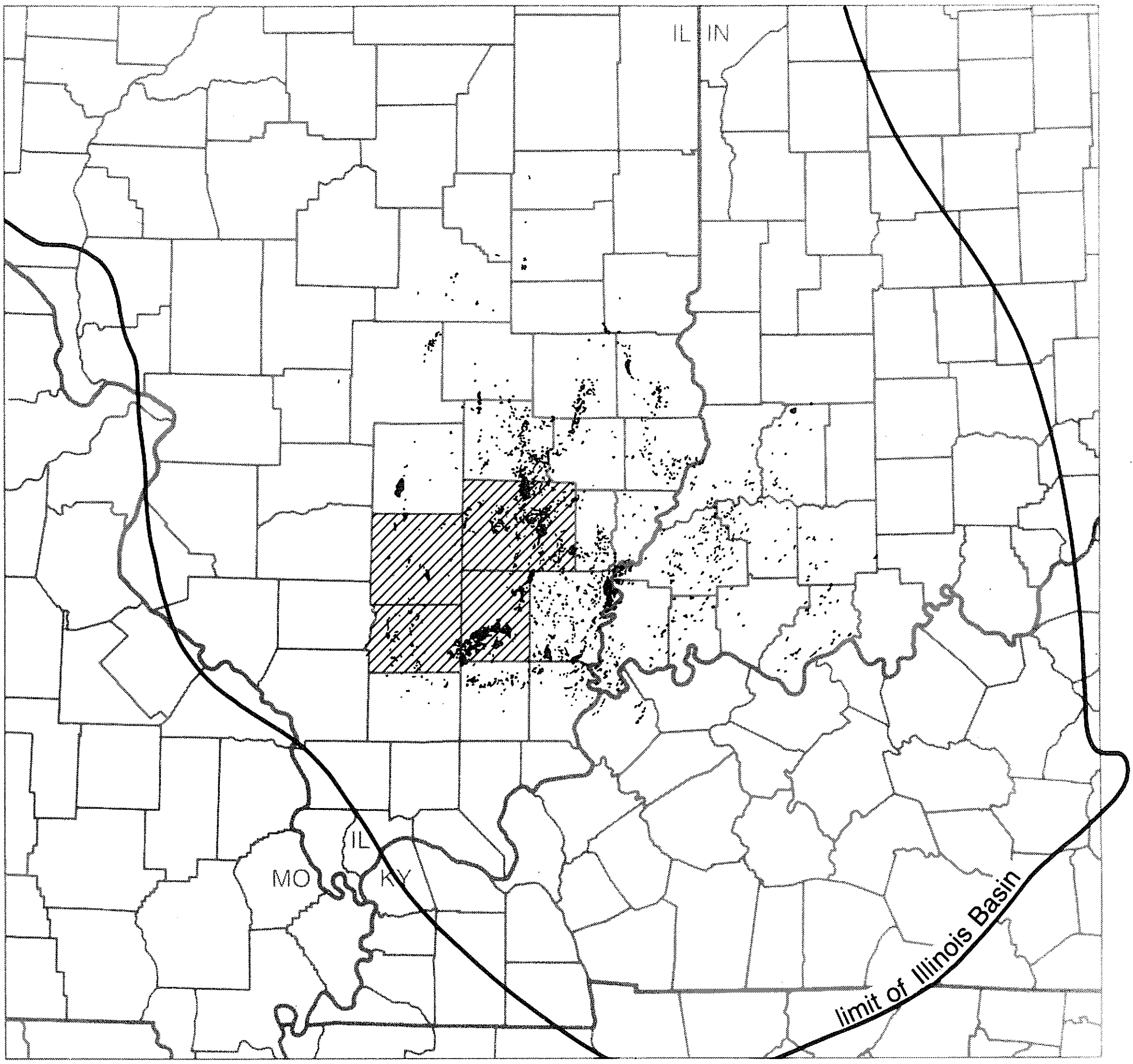

Figure 2 Regional map showing study area and Aux Vases producing fields (after Howard, in press).

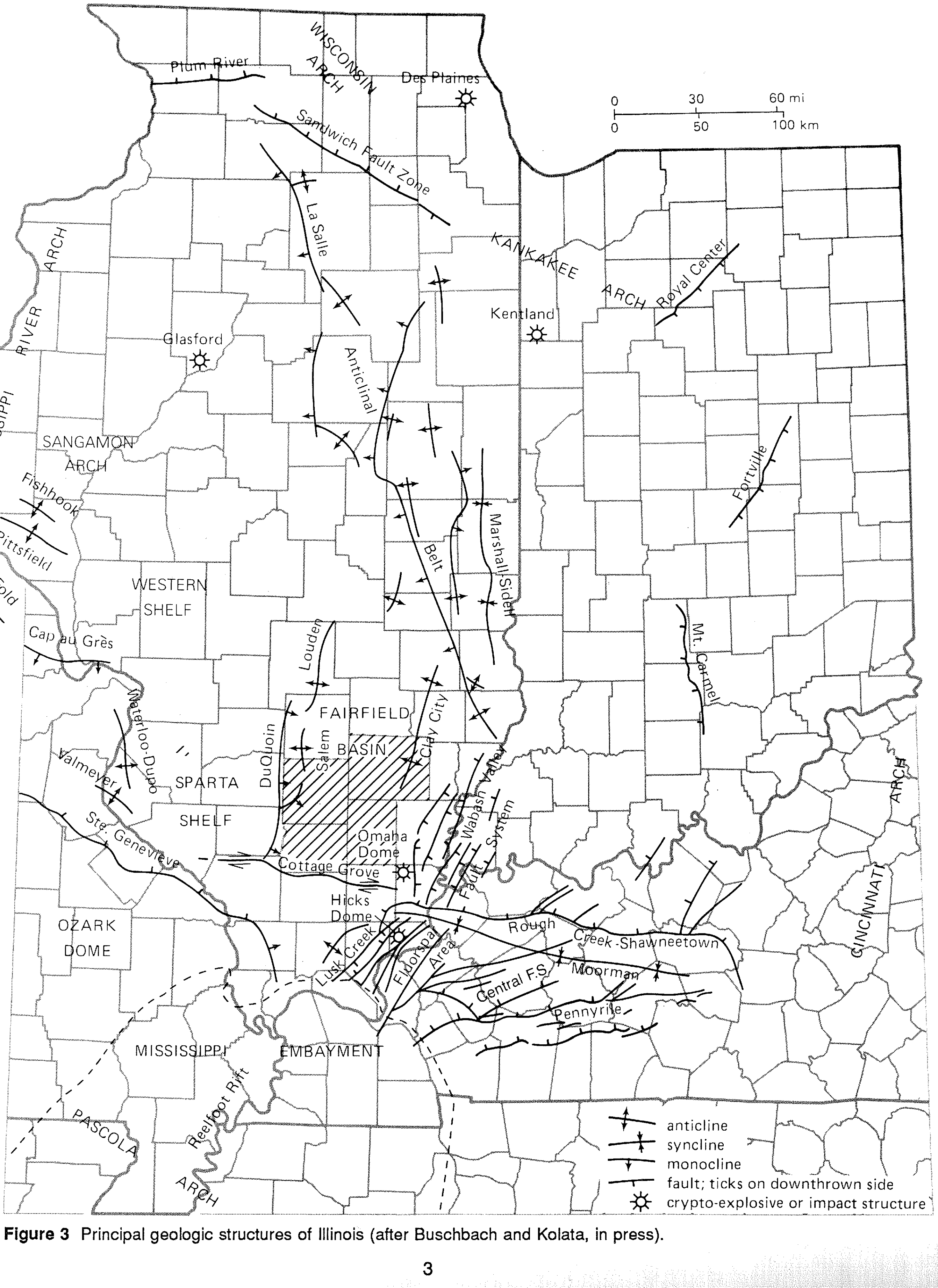

Figure 3 Principal geologic structures of Illinois (after Buschbach and Kolata, in press).

BRIEF DESCRIPTION OF OLD ELECTRIC LOGS

Old electric logs are wireline logs that combine the spontaneous potential (SP) and the normal and lateral resistivity curves. By 1956, the induction log began replacing the electric log as the primary resistivity measurement tool (Hilchie 1979), although in the Illinois Basin, electric logs continued to be run during the early 1960s.

The SP measures the potential that has developed opposite a permeable bed in a natural electrochemical cell composed of shale, freshwater, and saltwater (Hilchie 1979). Griffiths (1952) showed an inverse relationship between the amount of clay and the magnitude of the SP. The SP-clay relationship is the basis for the technique of estimating porosity presented in this report. Although the SP measures the amount of clay, not porosity and permeability, an increase in clay implies a corresponding decrease in porosity and permeability.

The normal refers to a log that was introduced by Schlumberger in 1931 and became the primary resistivity curve in the early electric log suite (Hilchie 1979). The type of normal is defined by the electrode spacing, usually referred to as the AM spacing, which determines the depth of investigation. In the Illinois Basin, many different electrode spacings were used, of which the most common were the 16-inch short normal (AM = 16 in.) and the 64-inch long normal (AM = 64 in.).

The depth of investigation of the normal is assumed to be twice the AM spacing (Hilchie 1979). At an AM spacing of 16 inches, resistivity is measured 32 inches from the borehole. At an AM spacing of 64 inches, resistivity is measured 120 inches (~10 feet) from the borehole. The short normal usually measures the average resistivity of the invaded zone (R_i), which is saturated with a mixture of mud filtrate and original formation fluid. The long normal measures the apparent resistivity (R_a) of the formation. Invasion and thin-bed effects can still affect the long normal. Simply stated, the long normal accurately measures formation resistivity if beds are thicker than 10 feet and invasion is less than 5 feet (Frank 1986).

The lateral, as a resistivity log, is of limited use in analyzing the Aux Vases Sandstone because beds must be thicker than 30 feet for the lateral to give an accurate value for formation resistivity (R_t). The Aux Vases in the study area is typically less than 30 feet thick and commonly less than 20 feet thick. The lateral is asymmetrical; it does not peak opposite the center of the bed, which complicates interpretation.

STRATIGRAPHY

The Aux Vases Formation is the uppermost unit of the Mississippian Valmeyeran Series (fig. 1). The Aux Vases Sandstone in southern Illinois commonly is fine to medium grained, moderately to well-sorted, and contains 81 to 98 percent quartz and up to 13 percent feldspar (McKay 1980, Weimer et al. 1982, Young 1983). Calcite, iron oxide, and quartz are the main cementing agents. A typical reservoir unit consists of a single porous, permeable lens, with a maximum thickness of 10 to 20 feet. Clean porous sandstone reservoirs grade into silty or calcareous sandstones and shales. In parts of the study area, the Aux Vases contains scattered limestone lenses up to 10 feet thick.

Clay minerals have a major effect on log measurements. The principal clay mineral groups represented in the Aux Vases are illite, mixed layer (undifferentiated), and chlorite (Smoot 1960, Wilson 1985, Seyler 1988). In addition to decreasing the size of the pore throats, clays also increase the surface area within the pores, thereby increasing the amount of clay-bound (immobile) water. The cation exchange capacity of these clays causes lower resistivity values and increases the calculated water saturation values.

The Aux Vases Formation is overlain by the carbonate-dominated Renault Formation. The Renault is relatively continuous in the eastern part of the study area (fig. 2), but becomes more discontinuous and difficult to correlate toward the western edge of the study area, where it changes to a sandstone-shale sequence and is indistinguishable from the Aux Vases. The resistivity of the approximately 10-foot-thick carbonate facies provides an excellent marker on electric logs.

Underlying the Aux Vases is the Ste. Genevieve Formation, an oolitic or crinoidal limestone with a fairly uniform electric log character. The Ste. Genevieve can be a good marker that enhances correlation, but differentiating the Ste. Genevieve from the Aux Vases limestone facies can be difficult.

DATA ANALYSIS AND METHODOLOGY

The distribution of the 70 wells from which both Aux Vases core data and electric log data were collected is shown in figure 4. Within each well, the log response of the Aux Vases was subdivided into zones of similar electrical properties that were calibrated with the core analyses. Most wells in this study had core from only one zone. In total, 73 zones (or data points) were used in this study.

Thin-bed corrections to the long normal do not need to be made if the zone is thicker than 10 feet. Beds thicker than 10 feet have minimal thin-bed effects, simplifying log analysis and making it more accurate. The assumptions made in thin-bed corrections make the corrections difficult to use (Hilchie 1982). In this investigation, no thin-bed corrections were made to the normal. Beds adjacent to the Aux Vases Sandstone usually have a resistivity greater than 10 ohm-m, which minimized some effects of the adjacent bed.

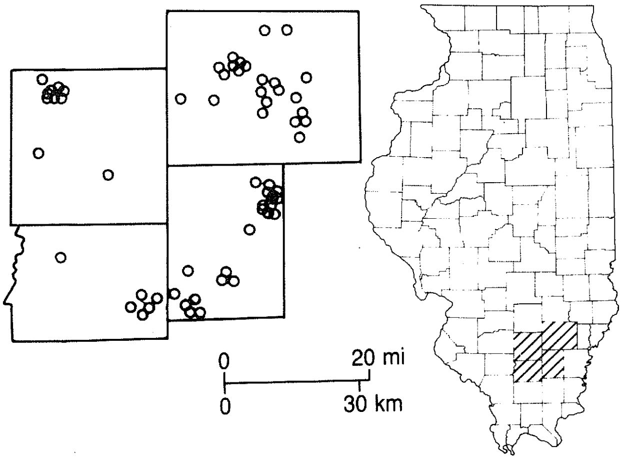

Figure 4 Location of wells for which both core and electric logs are available in study area.

Beds can be as thin as 5 feet before SP thin-bed corrections need to be made. Thus, thinner beds can be analyzed with the SP than with the normal. If the SP curve shows a flat top, it can be an indication that the SP is approaching static SP (the true SP under ideal conditions).

Seventy-three zones from the 70 Aux Vases wells were used to define the SP-resistivity-core relationship. Although the average SP and short normal were measured for each zone, the relation of the short normal to porosity was determined in only 47 wells because not all of the wells had a measured mud resistivity (R_m). For each zone, porosity and permeability values were taken from commercial core analyses. Core measurements are subject to error, and different methods of porosity measurement can yield different results (Corelab 1979). All core analyses used in this report were done before 1960.

For purposes of log analysis, the resistivity of the drilling mud (R_m) and the temperature at which the R_m was measured are two of the most important pieces of information required. Since the resistivity of the mud changes with temperature, R_m must be corrected to formation temperature before it can be used in any log calculations. Almost 40 percent of the 70 wells do not have the mud temperature listed, and therefore, these wells have no usable R_m. As will be discussed later, some wells may also have had the R_m or the temperature measured incorrectly.

POROSITY

Three methods of predicting porosity from old electric logs are discussed: short normal, Rocky Mountain, and normalized SP (NSP). The first two methods are commonly used in the industry, but have several limitations. Of the three methods, the NSP appears to provide the best results for the Aux Vases in the study area.

Short Normal Method

Pirson (1957) and Hilchie (1979) describe procedures and provide nomographs for estimating porosity from the short normal. The techniques are empirical and based on short normal measurements of the resistivity of the invaded zone.

The calculation of porosity from the short normal curve requires the following four conditions: (1) invasion of drilling fluid into the formation is moderate or deep; (2) porosity is less than 25 percent; (3) the formation has intergranular porosity and little shale; and (4) the R_m measurement is accurate (Hilchie 1979). Of these conditions, the accurate R_m measurement may be most critical, because all of the methods used to derive porosity from the short normal involve a ratio of the resistivity of the invaded zone to R_m. Aux Vases Sandstone porosities calculated using the short normal generally correlate very poorly with the actual measured porosities from core when R_m is taken from the log heading (fig. 5). All calculated porosity values greater than 30 percent were plotted at 30 percent porosity, because measured porosities for the Aux Vases were never greater than that value.

An approximate R_m was calculated from the logs to determine whether the measured R_m was a major source of error. In this method, the Cypress sand (fig. 1) was used to estimate R_m. The thick well-sorted clean sandstone of the Cypress displays a distinctive log character and has a relatively uniform porosity of 16 to 22 percent. In this study, the porosity of a clean Cypress sand was defined as having an average porosity of 18 percent. An approximate value for R_m can be estimated by reversing the regular Pirson method (Pirson 1957) of calculating porosity from the short normal. This reverse method requires that the porosity of the Cypress remain relatively constant from well to well.

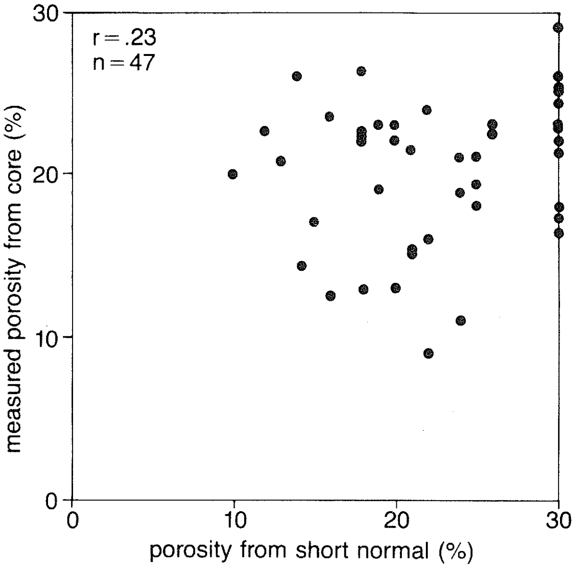

Figure 5 Measured core porosity compared with porosity calculated from the short normal (R_m in the porosity calculation was taken from the log heading).

With the reverse Pirson method, variations in the actual porosity of the Cypress cause errors in the estimated R_m. The calculated porosity of the Aux Vases using the estimated R_m is a somewhat better approximation of the measured core porosity (fig. 6) than the porosity calculated using the R_m from the log heading (fig. 5). This observation suggests that the R_m values on the log headings are incorrect for a significant number of the evaluated wells.

The parameter R_m is used in many critical log interpretation calculations. For instance, it is an intrinsic part of estimating resistivity of formation water (R_w) from SP and of estimating porosity using micrologs (Hilchie 1979). The measured R_m from old electric logs in the Illinois Basin apparently is not reliable; corresponding calculations using the measured R_m are suspect.

Rocky Mountain Method

The Rocky Mountain (Tixier) method permits the determination of water saturation and porosity when only R_t, resistivity of the invaded zone (R_i), and SP are known (Schlumberger 1955, Tixier 1949). Use of this method is appropriate where

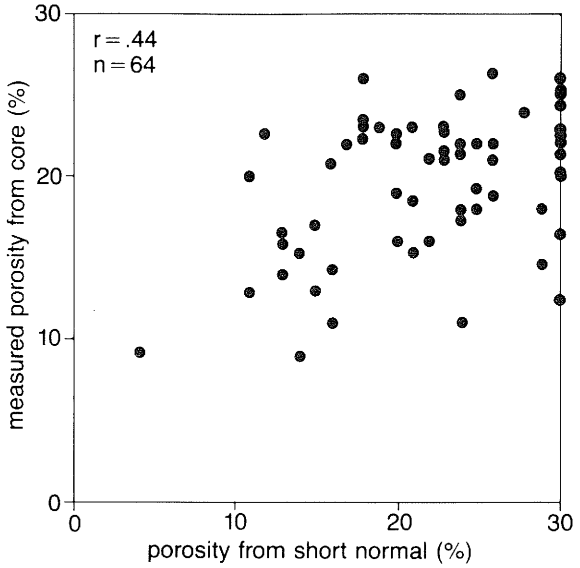

Figure 6 Measured core porosity compared with porosity calculated from the short normal (R_m in the porosity calculation was estimated using the Cypress sand).

moderate or deep invasion of the mud filtrate has occurred (Hilchie 1979). The short normal is used as a porosity indicator and the SP as an indicator of R_w. The nomograph used in the calculations can be found in the above references.

The Rocky Mountain method compares the resistivity deflection of the shallow tool (short normal) to the resistivity curve of the deep investigation tool (long normal). The Rocky Mountain method has three limitations that are similar to those of the short normal method: (1) the invaded zone must have a diameter large enough for the short normal to read this zone; (2) the long normal must measure a value of R_t and not be overly affected by the invaded zone; and (3) the beds must be thick enough that bed thickness corrections are not required (Pirson 1963).

The porosity values calculated from the Rocky Mountain method were compared with core porosity measurements (fig. 7). Again, all porosity values calculated at greater than 30 percent were plotted at 30 percent porosity.

The Rocky Mountain method produces better estimates of porosity than does the short normal method. In the Rocky Mountain method, the difference between the core porosity and the calculated porosity is, in some instances, as high as 10 percent, but the standard error of estimate is 3.4 percent porosity.

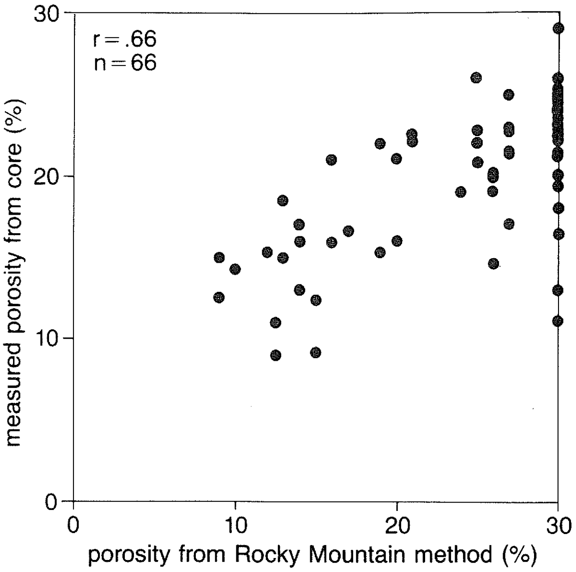

Figure 7 Measured core porosity compared with porosity calculated using the Rocky Mountain method.

Because of the erratic results, the use of the Rocky Mountain method in the evaluation of the porosity in the Aux Vases Sandstone is not recommended. The method probably is not effective because the depth of invasion is different in the various wells. The difference in the radius of invasion could be due to changes in permeability of the formation, changes in the mud characteristics, and the length of time that the formation was subjected to invasion (Hietala and Connolly 1984).

Normalized Spontaneous Potential Method

Because the actual value of SP on the log is not an absolute number, SP values cannot be directly compared among different wells. Normalizing SP values against an internal standard can compensate for changes in the scale of the log, the mud resistivity, and the size of the borehole, and thus allows direct comparisons of SP values between different drill holes.

The Cypress Sandstone, which occurs some 200 feet above the Aux Vases, was used in this investigation to normalize or standardize the SP curves. The Cypress is commonly more than 100 feet thick and consists of multiple sandstone bodies that can each be more than 50 feet thick. Cypress sandstones are typically light gray to white, fine to medium grained, angular, and friable. Analyses of numerous Cypress cores reveal that porosity and permeability values are relatively consistent. Therefore, the Cypress appears to be especially suitable as a standard for normalizing SP.

Wells drilled with freshwater exhibit positive SP deflections in shales, and where shale is the dominant lithology, tend to follow a straight line, called the shale baseline (fig. 8). In permeable sandstones, the SP response is negative and approaches a constant value corresponding to a response of a well-sorted sand containing almost no clay matrix between the sand grains (the clean sand baseline). Flattening of the SP response of a sandstone to a nearly horizontal line across the log chart indicates that the SP value at maximum deflection is close to the static SP of the formation. If the SP curve is not flat, then the bed is probably too thin to permit determination of static SP.

The position of the shale baseline on an SP log is arbitrary; the millivolt readings are not referenced to an absolute value (Schlumberger 1972). The scale (deflection from the shale baseline) of the SP and the location of the shale baseline are set by the logging engineer and vary from well to well.

The ratio of resistivity of the mud filtrate (R_{mf}) and the R_w has a profound effect on the magnitude of the SP and is different in each well. The greater the contrast between the resistivity of the mud filtrate and the formation water, the greater the difference in the millivolt values between the shale baseline and the clean sand baseline for the log (Schlumberger 1972). Conversely, an increase in hole diameter tends to reduce the amplitude of the SP response across permeable beds (Frank 1986). Normalization reduces the effects of both borehole size and mud resistivities when SP values of different wells are compared.

The first step to normalize the SP measurements is to establish a shale baseline (SP_{min}) through the average SP curve in a thick shale. Similarly, a clean sand baseline (SP_{max}) is established. For this study, the sand baseline was defined from the Cypress sand (fig. 8) with the largest negative millivolt value. The millivolt values for the shale baseline and the clean sand baseline established for each log record were input with the SP for the zone of interest in the normalizing equation. The NSP values are unitless and range from 0 to 100.

$$NSP = \frac{|SP_{log}| - |SP_{min}|}{|SP_{max}| - |SP_{min}|} \times 100 \qquad [1]$$

where

SP_{max} = average maximum SP reading (mV) for a clean Cypress sandstone

SP_{min} = average SP (mV) at the shale baseline

SP_{log} = SP value (mV) for the zone of interest

In the area of investigation, each well was standardized using the value for the cleanest thick Cypress sand encountered in the well (SP_{max}) as a reference. Changes in the Cypress can be monitored on the log by visually comparing it with another clean thick sand, such as the Tar Springs, 200 feet above the Cypress interval.

The shale baseline is usually relatively easy to determine on the SP curve, but as seen in figure 9, some wells in the study area have a baseline shift occurring in the Cypress Formation. Two explanations are possible. These baseline shifts can occur when formation waters of different salinities are separated by a shale bed that is not a perfect cationic membrane (Pied and Poupon 1966). Another possibility is that the logging engineer mechanically shifted the baseline in the well. The normalization procedure is not valid in these wells and they were not included in the analysis.

The relation between NSP and measured core porosity in 73 zones (all counties in this study area) has a Pearson correlation coefficient (*r*) of 0.83 (fig. 10). The equation of the least-squares regression line relating porosity and NSP is

$$\phi = .208(NSP) + 2.009 \qquad [2]$$

where ϕ = porosity measured from core (%)

The data exhibit considerable scatter or deviation from the least-squares regression line. More than a 5 percent porosity difference can occur between the core analysis and the predicted porosity calculated using the best fit regression line. However, most wells show a significantly smaller amount of error. The calculated standard error of estimate is 2.6 percent porosity. As shown in figure 10, the two lines drawn parallel to the regression line at a vertical distance equal to the standard error of estimate will by definition include two-thirds of the points from a given sample (Alder and Roessler 1960).

Modern porosity tools, such as density and neutron logs, can also have errors of about the same magnitude. Lang (1980) determined that 58 percent of the wells in a 360-acre area in the San Joaquin Valley of California needed correction. The average correction was 3 percent porosity.

Although linear regression analyses were calculated separately for Jefferson, Wayne, and Hamilton Counties, the results for these individual counties

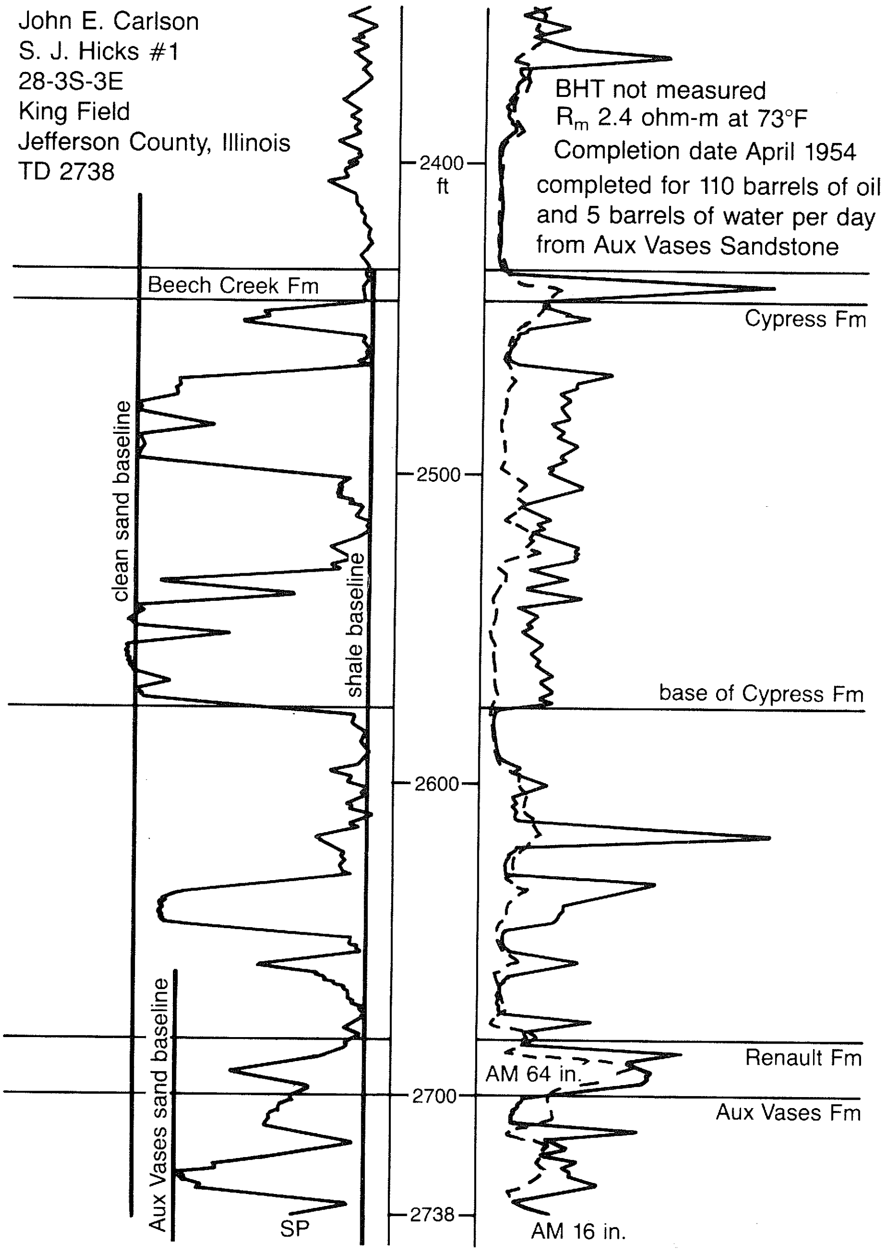

Figure 8 Electric log of the Cypress and Aux Vases interval showing the sand baseline and the shale baseline.

are not as valid as the combined analyses for all four counties. For a single county with a low number of wells, a single well can unduly influence the regression results. If the measured values for a single well were in error, then the regression line could be in error.

The relationship between NSP and porosity in Jefferson (fig. 11), Wayne (fig. 12), and Hamilton (fig. 13) Counties appears to be comparable. However, Hamilton County is of particular interest because of the large number of data points that form a vertical cluster where NSP = 100. Reasons

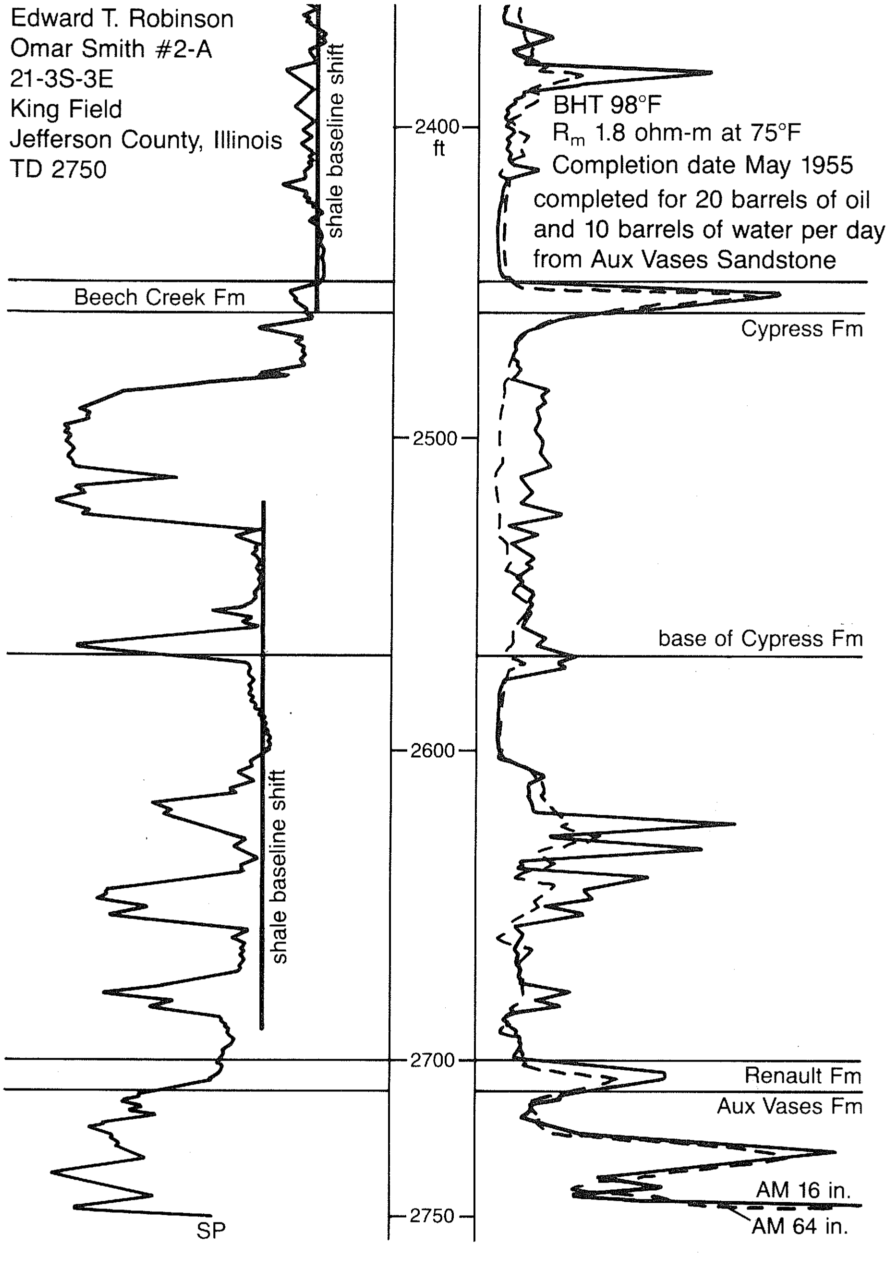

Figure 9 Electric log of the Cypress and Aux Vases interval showing SP baseline shift.

for the large number of such points in Hamilton County are discussed later in Permeability.

Boundary effects also cause part of this vertical clustering of points at NSP = 100. In the normalization procedure, the SP is compared with the clean Cypress sand. The NSP cannot be greater than 100. Therefore, if the Aux Vases Sand has an SP equal to or greater than the Cypress, it must be equal to 100.

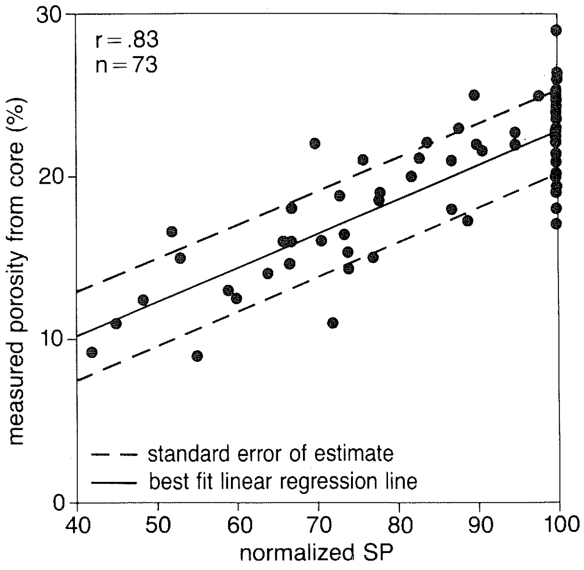

Figure 10 Measured core porosity relative to NSP for all counties in study area. Two-thirds of data values will fall within the bounds of the standard error of estimate.

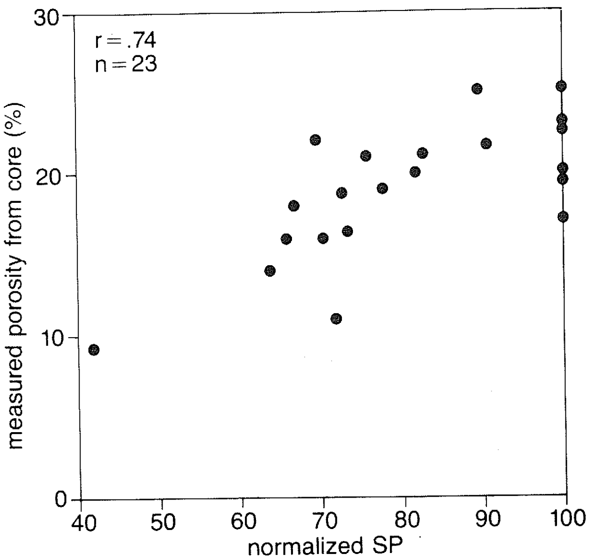

Figure 12 Measured core porosity relative to NSP for Wayne County.

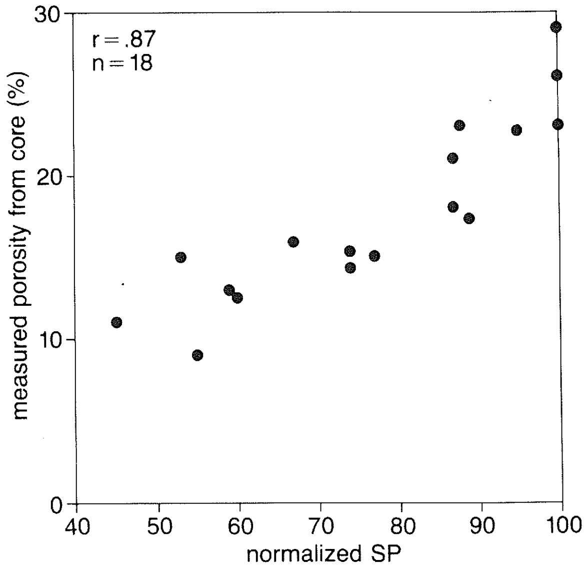

Figure 11 Measured core porosity relative to NSP for Jefferson County.

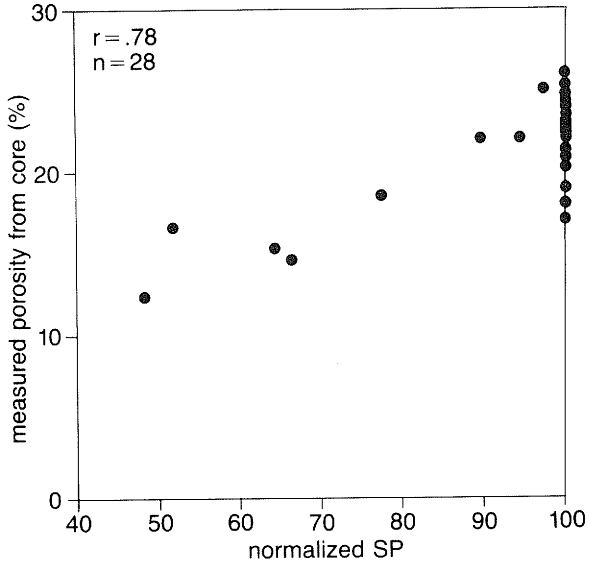

Figure 13 Measured core porosity relative to NSP for Hamilton County.

The best fit line, equation 2, should be used with some caution when porosity is estimated. If core data from the field indicate an average porosity that is lower or higher than the predicted porosity from the linear regression, core data should be substituted on the plot and the curve modified. The determination of the Aux Vases porosity from the SP log in this study is based on a local empirical relationship. The equation defining this relationship should be used only for the four-county area for which it was derived. The technique should not be used with another formation or lithology without careful calibration of the SP response to measured core data. The analysis was done on Aux Vases sandstones, and the results are not valid for limestones.

PERMEABILITY

A logarithmic relationship can be seen between average core porosity and core permeability (fig. 14). This relationship is linearized by using the log of the permeability value. A direct correlation also exists between the NSP and log of the permeability (fig. 15). Kolodzie (1980) found a general relationship between permeability and NSP, and estimated permeability by using the NSP.

Unlike the NSP-porosity relationship, the NSP-permeability relationship is not linear. Measured permeability values for the Aux Vases plotted against NSP show a wide range. Therefore, this method cannot be used in general reservoir studies to predict permeabilities. For example, in figure 15 for an NSP value in the mid-60s, measured permeability ranges from <10 md to >100 md. Aux Vases sandstone wells with permeabilities <10 md are not commercial, whereas those at 100 md can be prolific producers.

In local areas such as Jefferson County, the NSP-permeability method may be useful (fig. 16). The NSP cross plots may work here because all of the Aux Vases was formed in a similar diagenetic and depositional environment. Subsequent work may document a relationship between NSP and permeability, which would allow semiquantitative predictions of some reservoir characteristics.

Least-squares regression analysis of permeability and NSP data from Jefferson County show a

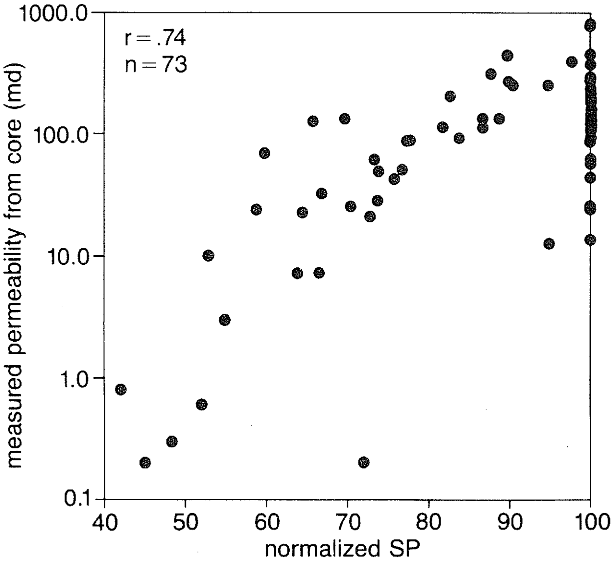

Figure 15 Measured core permeability relative to NSP for all four counties.

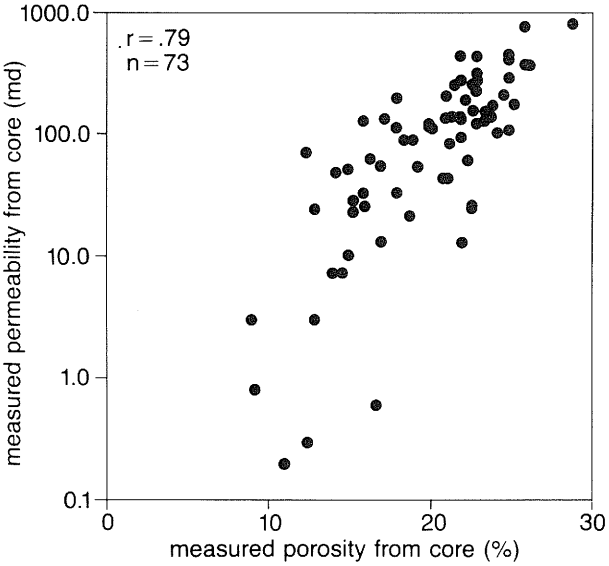

Figure 14 Measured core permeability relative to measured core porosity.

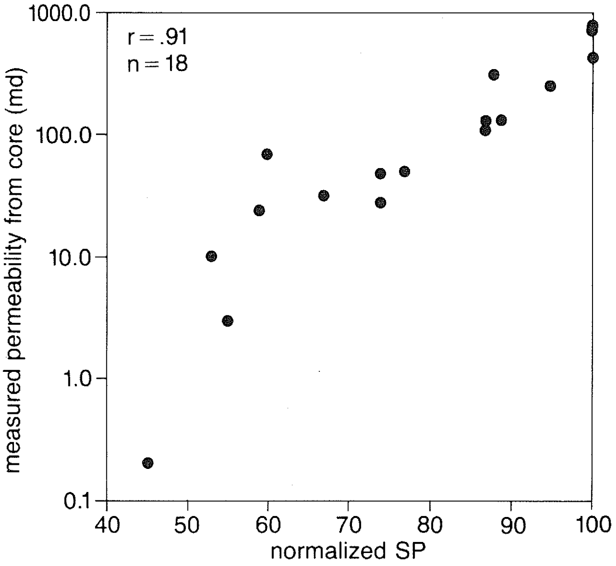

Figure 16 Measured core permeability relative to NSP for Jefferson County.

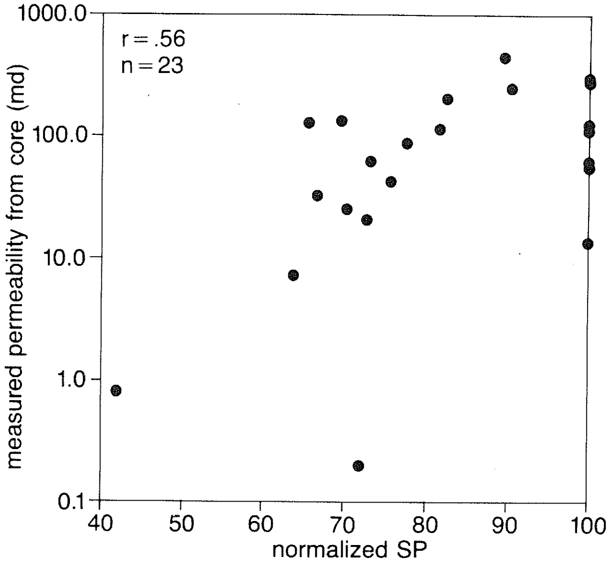

Figure 17 Measured core permeability relative to NSP for Wayne County.

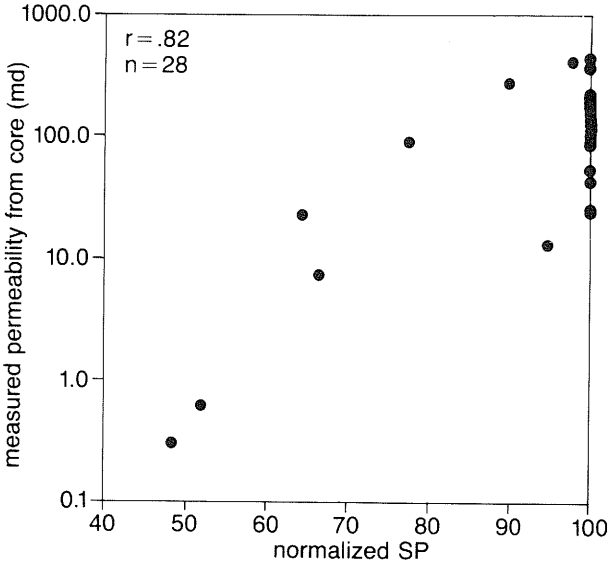

Figure 18 Measured core permeability relative to NSP for Hamilton County.

correlation of 0.91 (fig. 16). This strong correlation results from Jefferson County having the fewest number of wells with NSP = 100. Wayne County (fig. 17) and Hamilton County (fig. 18) have large percentages of wells with NSP = 100. The high number of wells with values of NSP = 100 for the Aux Vases Sandstone in Hamilton County may be due to differences in the nature and amount of matrix in the Aux Vases in Hamilton County. The inferred source of the Aux Vases Sandstone is from the west and northwest of the study area (Swann and Bell 1958). Of the three counties studied, Hamilton is the farthest from the source area, and it should exhibit the highest calcite content and the lowest clay content. This relationship is partly confirmed by Wilson (1985), whose data indicate a decrease in the clay matrix of Aux Vases reservoir rock in Hamilton County compared with that of the other counties in the study area. An inverse correlation exists between the magnitude of the SP and the percentage of clay. High NSP values for the sands in Hamilton County may be due to their relatively low clay content. Although these sands appear "clean" on the SP, their permeability may have been reduced by calcite cement.

An approximation for permeability when NSP = 100 could be obtained in Hamilton and Wayne Counties by using the average permeability at NSP = 100. Here, both counties have an average permeability of 100 md.

WATER SATURATION

Calculating accurate values of water saturation (S_w) for Aux Vases Sandstone from the data available in Illinois has been a problem for years. Water saturation values, including those calculated from modern log suites, can be as high as 60 to 80 percent for wells in the Aux Vases Sandstone that produce little or no water (Seyler 1988). On the other hand, some Aux Vases wells have high water saturations and produce water. This great variability of S_w values in producing wells complicates the well evaluation process.

The high S_w values in producing wells are probably caused by two factors: (1) the cementation exponent used in the formation factor relationship of the Archie equation was too high (Archie 1942), and (2) clay was present in the formation.

The most common method used to calculate water saturation in rocks that contain little clay in the matrix is the basic Archie equation (Archie 1942):

$$S_w = \sqrt{\left(\frac{FR_w}{R_t}\right)} \qquad [3]$$

where

S_w = water saturation (%)
R_w = resistivity of formation water (ohm-m)
R_t = resistivity of the formation (ohm-m)
F = formation factor

In the Archie equation 3,

$$F = \frac{1}{\phi^m} \qquad [4]$$

where

m = cementation exponent
ϕ = porosity (%)

The cementation exponent (m) is the most difficult of the variables in the Archie equation to determine. The value of m is dependent on pore geometry and equals 2 in sandstones that contain no clay matrix. In sandstones with a substantial amount of clay, m can be as low as 1.7 (D. Hartmann, personal communication 1990). A common method of compensating for the effects of clay on old electric logs was to vary the cementation exponent. In some cases, a value of m as low as 1.5 was used (Hilchie 1979). These low m values are not actual values measured from the rock; however, low cementation exponent values can produce realistic water saturations in shaly formations. This method of using artificially low m values is basically a simplified version of the modern shaly sand calculations. The Aux Vases at King Field, which will be discussed latter, has clay in its rock matrix. For this reason, the cementation exponent of the Aux Vases at King Field was assigned a value of 1.7.

Winsauer et al. (1952) showed that the cementation exponent has lower values for better sorted, slightly cemented sands than for those that are heavily cemented. Doveton (1986) also found the cementation exponent to be sensitive to the depositional fabric or bedding of the rock. On a regional scale, the Aux Vases will have significant variations in both the clay content and distribution of the clay in the pore throat, which will cause corresponding variations in m.

Pessimistic S_w values result from using $m = 2$ for clean sandstone in the Archie equation when an $m = 1.7$ better reflects the clay percentage. Constant m values should not be used on a regional basis for calculating S_w from the Archie method or any analytical method that uses the cementation exponent. On a local scale, m should not vary significantly, and reasonable water saturation values can be calculated using a constant value for m.

If the value of m is assumed to remain relatively constant over an area, yet its value is unknown, a Pickett plot or log-log plot of resistivity relative to porosity values can be effectively used to estimate water saturation (Pickett 1973, Lang 1973). The Pickett plot is a graphic derivation of the Archie equation. The initial step in analyzing well logs using the Pickett plot method is to define the 100 percent S_w zones on a log and use these zones in defining resistivity of a formation 100 percent saturated with formation water (R_o). The R_o values when plotted relative to porosity establish the R_o line. All other water saturation percentages are calculated from the initial R_o line. The slope of the R_o line on the Pickett plot reflects the value of m.

Note that the Pickett plot will work only if m stays constant throughout the study area and the resistivity tool has the same depth of investigation. The long normal (AM64) was used in this study. Measurements made with different types of tools cannot be mixed together on a Pickett plot. For example, values of resistivity from the induction tool cannot be used together with values from a long normal tool.

A Pickett plot analysis was used to determine the water saturation of King Field, which has produced more than 4 million barrels of oil from the Aux Vases sand. All of the wells that had usable logs were plotted on the Pickett plot (fig. 19). The porosity was calculated using the NSP method; resistivity was measured from the long normal.

When m is constant, porosity and resistivity from those wells that either tested water or were drilled below the oil-water contact should ideally plot along a straight line on log-log graph paper (Lang 1973). At King Field, the oil-water contact is not well defined, and some of the wells that have been interpreted as wet may contain oil. All of the wells drilled into the postulated water zone plot below S_w >50 percent. The data are more scattered than on modern logs. This scatter probably resulted from error in using estimated porosity from the SP. Constant water saturation lines are plotted to the right of the R_o line and parallel to it. Hydrocarbon-bearing zones occur to the right of the R_o line. The equation (Hilchie 1982) used to calculate the position of the S_w lines is

$$R_t = \frac{R_o}{(S_w)^2} \qquad [5]$$

where

R_t = resistivity of the formation (ohm-m)

R_o = resistivity of the formation 100 percent saturated with formation water (ohm-m)

S_w = water saturation (%)

To use this equation, a porosity value must first be determined. The R_o value corresponds to a particular resistivity value at the selected porosity. With the Pickett plot of King Field used as an example, the corresponding value of R_o for a porosity of 25 percent is 2.2 ohm-m (fig. 19). For S_w = 50 percent, the calculated R_t value is 8.8 ohm-m at 25 percent porosity. For all different porosity values, an S_w = 50 percent defines a linear trend of resistivity values that is parallel to the R_o line, with resistivities four times higher than the R_o line. The

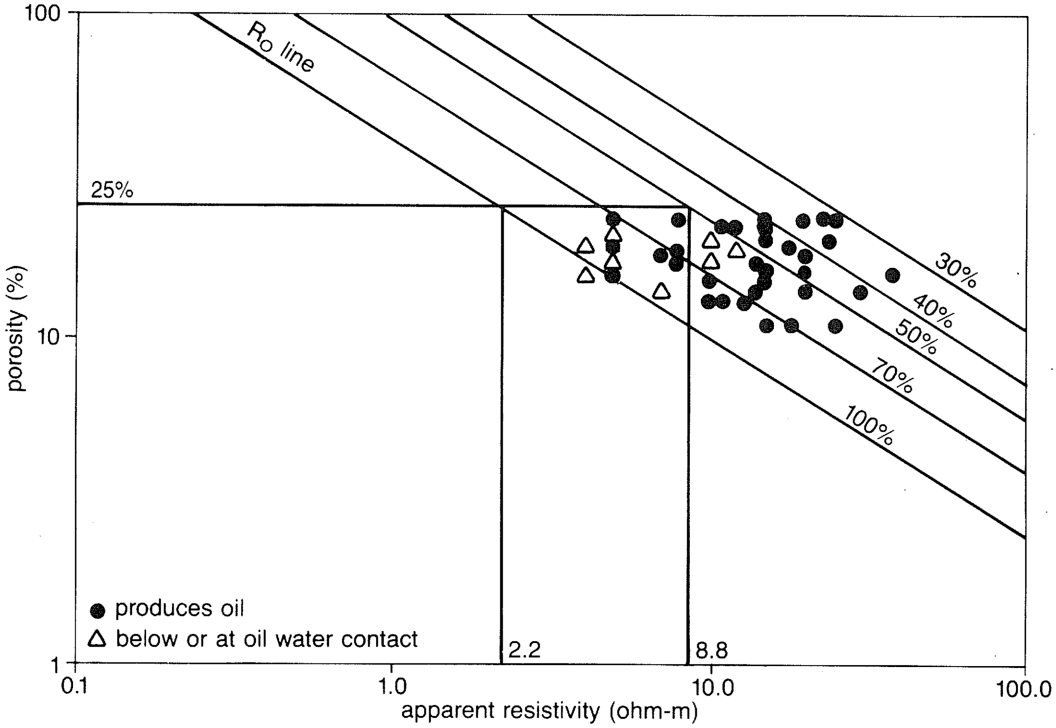

Figure 19 Pickett plot of estimated porosity relative to apparent R_t from the short normal for King Field, Jefferson County. The slope of the R_o line is equal to a cementation exponent of approximately 1.7.

same principle is used to establish any other S_w percentage.

The long normal can be used for the Pickett plot analysis, since an actual R_t value is not necessary and the long normal response commonly was obtained from deep enough in the formation to approximate R_t. If different wells are to be compared, then the resistivity tools must have a similar electrode spacing and measure approximately the same distance into the formation so that the Pickett plot method will be valid. That the long normal response may be from part of the invaded zone is ignored in the Pickett plot. Therefore, the actual long normal values can usually be plotted without having to take the invasion profile into account.

In theory, the intercept of the R_o line at 100 percent porosity should be the value of R_w. If the resistivity log is not measuring a true R_t, the intercept will not be R_w but instead will be a value between R_w and R_{mf}. For King Field, the long normal tool is not an accurate R_t measuring device but is actually measuring part of the invaded zone. Because multiple wells have diverse R_{mf} values, the resistivity intercept at 100 percent porosity is not a true R_w value.

SUMMARY

In Hamilton, Wayne, Franklin, and Jefferson Counties, the NSP technique was significantly better than were the short normal and Rocky Mountain methods in predicting porosity in the Aux Vases Sandstone. The NSP in relation to core porosity had a correlation coefficient of 0.83. The short normal R_m from the log heading, short normal R_m calculated, and Rocky Mountain methods had correlation coefficients of 0.23, 0.44, and 0.66, respectively. The measured R_m reported on old electric logs in the Illinois Basin is not a reliable value, so calculations using R_m may be in error.

The NSP cannot be used to accurately predict permeability. Although calculated values commonly are the correct order of magnitude, but they usually are not accurate enough for detailed reservoir analysis.

Water saturations can be estimated by using Pickett plot analysis. The major advantage of Pickett plots over the basic Archie equation is that Pickett plots do not need the cementation exponent or the resistivity of the formation water to be predefined.

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APPENDIX

The following example is a step-by-step log analysis of the Aux Vases Sandstone in King Field, Jefferson County, Illinois. Figure 8 is the sample well log for which the analysis will be done.

Step 1

Calculate the NSP from the log:

$$SP_{max} = -126$$
$$SP_{min} = -16$$
$$SP_{log} = -100$$

$$\frac{|-100| - |-16|}{|-126| - |-16|} \times 100 = NSP = 76$$

Step 2

Plot on figure 10 the value for NSP. Using the best fit line, determine the porosity of the well. With this method, porosity = 18 percent. The alternative method is to input the NSP value into the equation:

$$\phi = 0.208(NSP) + 2.009$$
$$18.0 = 0.208(76) + 2.009$$

Step 3

Read the apparent resistivity of the AM64 long normal curve:

$$R_a = 15 \text{ ohm-m}$$

Step 4

Use the porosity calculated from step 1 and the apparent resistivity from step 4 in the Pickett plot (fig. 19) to estimate a S_w = 55 percent.

Summary

This well was an oil producer with an initial potential of 110 barrels of oil per day and 5 barrels of water per day. This oil production confirms that the well has a low S_w. This S_w value is quite acceptable, especially since no bed thickness corrections were made to the SP or the AM64.

In this example, the true SP (or static SP) is probably higher than the SP curve shows. The SP curve does not have the flattening usually indicative of a static SP value. The bed is nearly 10 feet thick; therefore, the AM64 is certainly not reading a true R_t value.

Most of the King Field wells encounter an Aux Vases that is 10 to 15 feet thick. So long as the beds adjacent to the Aux Vases have similar resistivity, the Pickett plot, because it is a pattern recognition method, ignores the error caused by thin-bed effect. All of the wells would have approximately the same resistivity correction, and the relative R_t would be the same after a thin-bed correction.