Correlating and Averaging Connate Water Saturation Data

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ABSTRACT

The use of simple hyperbolic relationships in correlating connate water saturation data is shown to have wide application in a variety of reservoirs. This can be of considerable practical significance to the reservoir engineer because volumetrically weighted average saturations for any combination of core samples, reservoir strata or lease areas can be obtained directly from such correlations with a knowledge of average porosity alone. Also, in systems represented by a simple equilateral hyperbola the porosity-saturation product is constant and hydrocarbon volumes are conveniently derived from the difference between the pore volume and a constant fraction of the bulk volume. Potential applications and limitations of the technique have been explored for a number of sand and carbonate reservoirs, and several examples are described.

INTRODUCTION

OF fundamental importance in all oil and gas reserve estimates is the concept of connate water saturation. In fact, as it is one of the most basic parameters, like pay thickness or porosity, connate water must be measured or estimated in any and all types of reservoir analyses. Because water saturations may range from as little as 1 or 2 per cent up to 100 per cent of the pore space within the same reservoir, it is common practice to condense the data into a single "average" value related to some other average reservoir characteristic such as porosity or permeability. Although such an average may be applicable to the reservoir as a whole, it can, in some cases, lead to appreciable errors if applied to individual wells or areas within the pool. Even when the entire pool is considered, there may be considerable difficulty in obtaining the correct average.

The use of permeability as a correlating parameter has long been popular (1, 2, 3), and in some reservoirs it may be the only reasonable choice. Difficulties, however, can be encountered in applying such relationships to obtain true average saturations. Porosity-saturation correlations have been given somewhat less attention in the literature, although they have been widely used in Western Canada and in some areas of the United States. There are inherently fewer problems in establishing representative average values from porosity relationships, as the differences between arithmetic and geometric means, medians and modes, and the effects of sample orientation, need not be considered.

Difficulties in applying saturation correlations may be compounded (frequently with little or no justification) by using a combination of correlating parameters. Both porosity and permeability, for example, may be jointly related to saturation in a single correlation. However, this may only reflect a mutual relationship between porosity, permeability and some other more basic rock property, while contributing nothing to the accuracy of derived saturations.

Undoubtedly, the irreducible connate water saturation in a rock is most directly related to properties other than the porosities and permeabilities normally measured in routine core analyses. Intuitively, it would be expected that the number and type of grain contacts or the exposed area of the mineral surface, as determined by the size and distribution of the pores, would have a controlling influence. However, until methods for determining such factors (5) can be routinely applied, correlations of a more indirect type must be used. How they can best be developed and how they should be used are matters of fundamental importance in establishing true average saturations.

TRUE AVERAGE CONNATE WATER SATURATION

As saturations have primarily a volumetric significance, the only useful average is one obtained by volumetrically weighting the data to obtain a representative arithmetic mean value. Other saturation averages, such as medians and modes, have no volumetric significance and cannot be used for reservoir engineering purposes. The recommended (4) calculation of a geometric mean permeability for use with a K versus S correlation is, of course, just an intermediate step in estimating the weighted arithmetic mean saturation.

The three most common sources of water saturation data are analyses of cores cut in oil or oil-base mud, restored state or other types of capillary pressure tests, and quantitative well log interpretations. Certainly there are broad limits on the accuracy of basic information from these sources. There may be almost any degree of reliability, depending on procedures used and the range of saturations represented. Where interstitial water saturations are high, the flushing of core samples by oil-base drilling fluid may have a significant effect. Improper coring and handling techniques can provide another source of error. In one instance, poor techniques resulted in erroneous data on three out of four oil cores taken by different companies in the same field. Contributing factors were thought to include surface and sub-surface contamination of the coring fluid, penetration of the pay zone prior to the change-over from water to oil-base mud, and improper core storage.

Imperial Oil Limited, Edmonton, Alta.

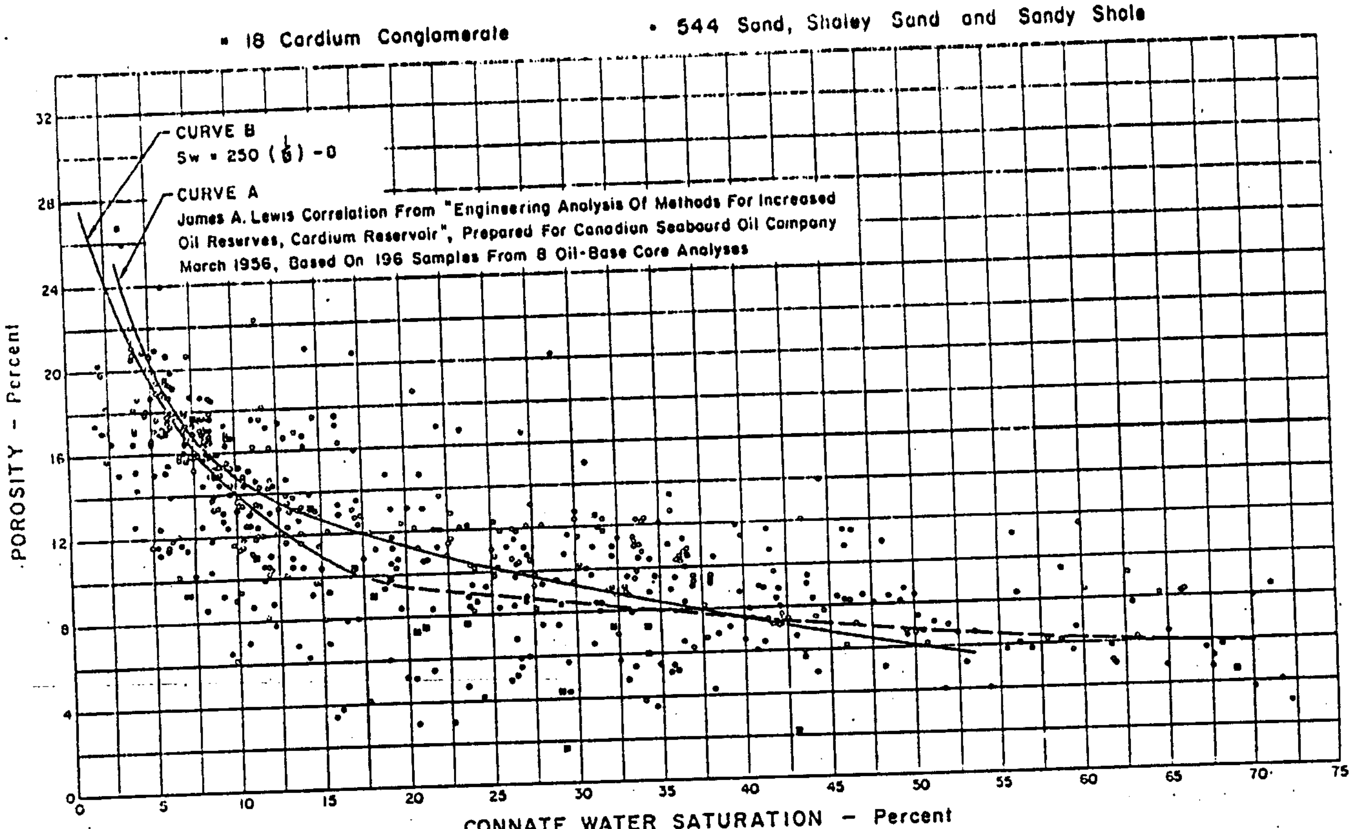

Figure 1.—Porosity vs. Connate Water Relationships for the Pembina Cardium Pool — 562 points from analyses of 19 oil-base cores.

Even the best oil-core data may be unreliable where porosities are low. Although water content may be measured with normal precision, this volume is expressed as a percentage of a pore volume having about the same magnitude as the probable experimental error. Therefore, the water saturations reported for cores having porosities of only 1 or 2 per cent can be considered, at best, as rough approximations. Possible errors of similar or greater magnitude must be recognized in the other methods of saturation determination. Indirect laboratory measurements may suffer from wettability and interfacial tension uncertainties, and induction log calculations, for instance, may tend toward increasing errors where saturations are low or where invasion is significant. In any case, if we are to avoid compounding errors, it is desirable to use a true volumetric mean value for whatever we believe to be the most reliable data available. This is the only number which, when multiplied by total pore volume, gives the correct total water content of the reservoir.

The process of volumetrically weighting saturation data can be exceptionally tedious. In a pool with 100 core samples for each of 100 wells, we would find, for example, that 10,000 calculations of ϕ x h x S would have to be made after picking 10,000 values from an appropriate correlation and assigning them to 10,000 individual core samples. It is not surprising, therefore, that short-cuts, although not necessarily valid, are frequently used as a "first estimate" in preference to the more rigorous approach.

Where saturations correlate with porosity, one of the most common estimating practices is to compute the average pool porosity and then interpret the corresponding connate water saturation from the established correlation. There is nothing fundamentally wrong with this procedure if a unique geometric relationship exists; often this relationship does exist, or is approximated for all practical purposes, even though we may fail to recognize it. If it does not exist, the value obtained from the saturation correlation at the average porosity will not be equivalent to a volumetric average. The unique relationship mentioned here is discussed in more detail under the heading "Average Saturations from Hyperbolic Correlations."

Two examples are given below to illustrate the difference between the average saturation and the saturation corresponding to the average porosity. The first example uses data from the Pembina Cardium pool. In this case, eighteen wells were selected so as to cover a wide range of average porosities. An available plot of porosity versus connate water saturation (*Figure 1*, Curve A) was accepted *per se*, and saturations were assigned to each core sample from the eighteen wells on the basis of individual porosity values. By totalling the thickness-porosity-saturation product for all plugs in each well, an appropriate average saturation was obtained in each case. At the same time, each well's average porosity was determined and corresponding saturations from the correlations were noted. From the ratio of the saturations obtained by the two methods, *Figure 2* was constructed and used in estimating volumetrically weighted saturations for about a hundred wells in a particular segment of the field. In this instance, the maximum difference between "true" (volumetrically weighted) average saturations and "apparent" averages, as shown by *Figure 2*, amounts to 15 per cent. In terms of hydrocarbon volume this is not particularly significant, as average oil saturations will be close to 90 per cent in any case.

Although the above example has limited quantitative significance, it does illustrate one approach toward estimating true volumetrically weighted aver-

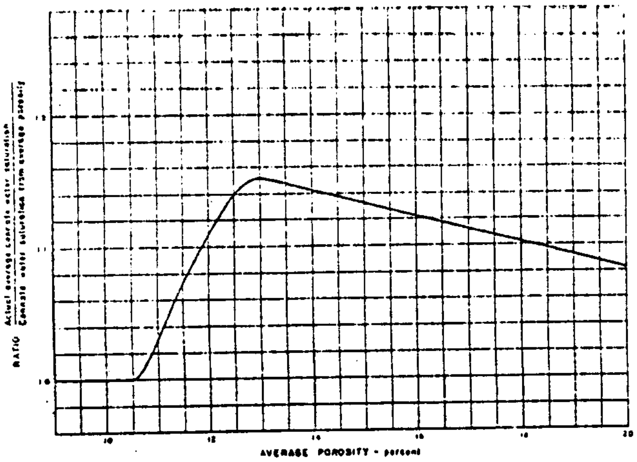

Figure 2.—Correction Factor for Connate Water Saturation (18 Pembina Cardium wells).

age saturations. The need for obtaining such an average, either rigorously or by any similar estimating procedure, may be better illustrated by the following example.

A Fort Saskatchewan Viking well's average porosity was found to be 21 per cent, which apparently corresponds to 45 per cent connate water from an available correlation of saturation and porosity data. With the data volumetrically weighted, the average was found to be 37 per cent. In this example, the gas-in-place calculated from the volumetric average saturation would vary by more than 10 per cent from the value calculated by taking the saturation directly from the correlation at $\bar{\phi} = 21$.

In general, the error which arises from using a saturation corresponding to average porosity instead of the volumetrically weighted average saturation is dependent firstly on how the porosity-saturation curve is drawn and secondly on the magnitude of the average connate water saturation.* Unfortunately, the usual free-hand approach to curve fitting may often be subjective enough to outweigh most other sources of error in interpreting saturation data. Also, the lower the saturation, the larger the error that can be tolerated, because, as in the Pembina example, hydrocarbon volume calculations are relatively insensitive to saturation data when the connate water is low. Regardless of the magnitude of error, however, there is a principle involved, which, as enlarged upon in the following discussion, can have appreciable significance in simplifying volumetric calculations and data processing techniques as well as in improving accuracy.

*This of course assumes that any transition zone is of negligible extent. The same applies in the case of permeability versus saturation correlations, where the possible error is, in addition, dependent on how the average permeability is obtained.

Hyperbolic Relationships

Connate water cannot be related to porosity in an ideal pore configuration of uniform structure. In such a system, the irreducible saturation can be varied by changing the particle size and surface area, but the porosity is fixed according to whatever grain structure exists. In rhombohedrally packed uniform spherical aggregates, for example, a wide range of irreducible saturations can be readily obtained by selecting different uniform grain sizes, but only one porosity (25.96 per cent) is possible.

In naturally occurring porous systems, greater particle angularity tends to increase porosity (4), and porosities lower than those of idealized systems can result from the increasingly non-uniform pore structure brought about by compaction, cementation, the dissolution of a dense matrix or simply by the gradation of particle sizes. In this sense, connate water can be a function of porosity only insofar as the porosity depends upon the variation of grain geometry and pore structure.

By considering a simple unconsolidated system, with porosity controlled by the variety of grain sizes, we can, by analogy, derive what should be a likely relationship between connate water saturation and porosity. *Figure 3-A* is a plot of surface area versus particle diameter for a geometrically homogeneous system (rhombohedrally packed spheres). We can postulate that a similar relationship will exist between surface area and *porosity* for samples of actual reservoir rock — *Figure 3-B*. This, in fact, must be the case if the relationship between porosity and mean particle diameter (or pore size) is approximately linear in a natural system. Artificial systems, with general characteristics related in principle to at least

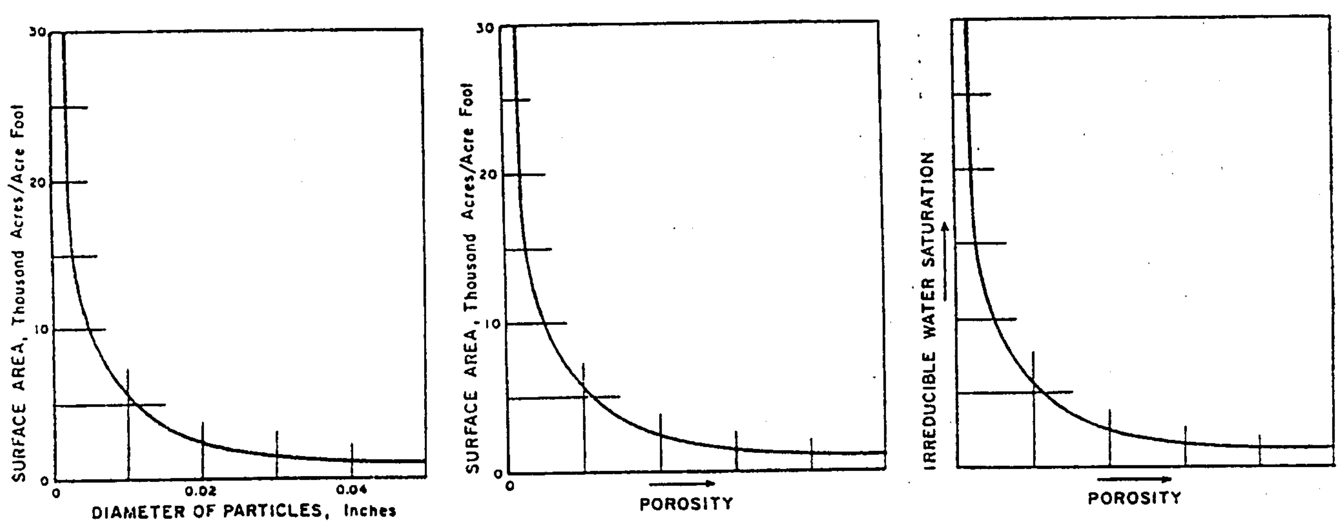

Figure 3-A *Figure 3-B* *Figure 3-C*

Figure 3.—Physical Properties of Porous Media — idealized and schematic relationships.

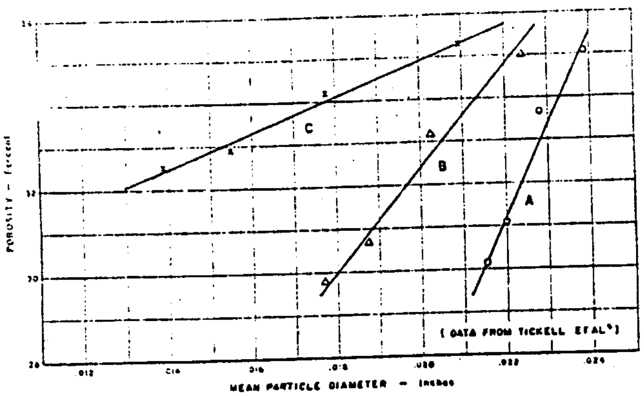

Figure 4.—Porosity and Particle Size Relationships for Unconsolidated Sand.

Line A — 80% coarse, 20% fines
Line B — 60% coarse, 40% fines
Line C — 40% coarse, 60% fines
(coarse −24+28 mesh; fines −32+35 mesh, −42+48 mesh, —60+65 mesh, —80+100 mesh).

some natural systems, do provide evidence of such linearity. Data obtained by Tickell *et al.* (6) can be cross-plotted, as in *Figure 4*, to show linear trends between porosity and average grain size for −24+28-mesh sand contaminated with various quantities of fines ranging in size down to −80+100-mesh (avg. 0.00634 inch).

Due to the angularity of the grains, actual surface areas for many sandstones would probably plot above the idealized and schematic curves of *Figures 3-A* and *3-B*. On the other hand, calcareously cemented sands and vugular carbonates would likely fall below (7). Nevertheless, it may be reasonable to expect a similar trend for actual and idealized systems.

Extending the analogy further, we can see that if irreducible water saturations in actual reservoir samples should be directly related to pore surface area, the relationship between saturation and porosity shown in *Figure 3-C* must result.

The equation of the first curve (*Figure 3-A*) is easily derived from the assumed geometry of the idealized system composed of spherical particles. It is simply $A = 53.3/d$, for "d" in inches and "A" in acres of surface area per acre foot (7). Similarly, if particle diameter "d" can be replaced by the linear function $a\phi \pm b'$ (considering the previous discussion of *Figure 4*), then the equation for the curve in *Figure 3-B* will be of the form $A = c'/(\phi \pm b)$, where c′ and b are constants. The third curve, being proportional to the second curve under the conditions postulated, must then be expressed by $S = C/(\phi \pm b)$, where C is a different constant. When b = o, the constant C is equal to the product ϕS, which is simply the irreducible water saturation expressed as a fraction of bulk volume instead of pore volume.

The relationship $S = C/\phi$ can be described as an equilateral hyperbola.* Alternate forms, such as $S = C/(\phi \pm b)$, as derived above, or $(S \pm a) = C/\phi$, will of course represent the same function, but with ϕ and S axis shifted by "b" units or "a" units, respectively.

*The equation $\frac{(y-a)^2}{k^2} - \frac{(x-b)^2}{h^2} = 1$ is the form commonly seen for a hyperbola with transverse axis parallel to the y axis. When k = h, this reduces to the rectangular or "equilateral" form: $(y-a)^2 - (x-b)^2 = h^2$. By rotating the axis through 45 degrees and establishing the center at (a, b) = (0, 0), this is translated to: $y = (h^2/2)(1/x)$, or xy = constant.

In processing empirical data, the foregoing derivation, through simplified analogies, suggests that there may be some basis for expecting hyperbolic correlations between connate water saturations and porosities. The forms which might be expected are:

Type I	— For origin at (a, b) = (o, o) $S = C/\phi$	or $\phi S = C$
Type II	— For origin at (a, o) $(S \pm a) = C/\phi$	or $\phi S = C \pm \phi a$
Type III	— For origin at (o, b) $S = C/(\phi \pm b)$	or $\phi S = C \pm Sb$
Type IV	— For origin at (a, b) $(S \pm a) = C/(\phi \pm b)$	or $\phi S = C' \pm \phi a \pm Sb$

The linearity of these inverse relationships further suggests that reciprocally ruled graph paper can be used to advantage in correlating saturation data. The possibility of a constant or nearly constant ϕS product (Type I — II), however, has implications of far greater significance and, therefore, practical reservoir engineering applications of the concept are explored here.

Practical Applications

Early Empirical Investigations

In 1953, an oil core was obtained at Imperial Leduc No. 509 (4-32-50-26W4). This was an Upper Devonian, Nisku (D-2) development well in Leduc-Woodbend, which provided as wide a range of permeabilities, porosities and facies types as any well in the field. More than 190 plugs were analysed, and later these data were supplemented by the analyses of two additional oil cores from the extreme southern edge of the field, 6 miles away. These were obtained at Imperial Leduc No. 595 (10-32-49-26W4) and Imperial Leduc No. 632 (15-29-49-26W4). Although the latter two cores were from an entirely different part of the field, their analyses gave points following the same correlation trend (*Figure 5*) already established for the No. 509 well. The accuracy of the oil core distillation results was verified by selecting thirty preserved samples at random and processing these at a different laboratory.

In the course of studying these data, it was discovered that a minor adjustment in the curve previously drawn through the connate water - porosity data would lead to a very convenient simplification applicable to all subsequent volumetric calculations. The adjusted curve, as shown in *Figure 5*, can be seen to provide an excellent fit with the available data. It is, in fact, an equilateral hyperbola with an equation of the form xy = constant, or, more specifically, $\phi S = 85$. The bulk volume water saturation in Leduc (ϕS), which was reported as early as 1953 as being "nearly constant," can be treated, therefore, as being precisely constant for all practical purposes. Accordingly, the hydrocarbon porosity (or oil saturation as a fraction of bulk volume), which is given by $(\phi)(1\text{-}S)$, can be reduced simply to $(\phi\text{-}0.0085)$, where both ϕ and S have been expressed as fractions rather than percentages.

By establishing that ϕS can be considered constant for Leduc D-2, the variable connate water factor is eliminated, and all volumetric calculations can be made solely on the basis of area, thickness and porosity data. In engineering studies of this reservoir, conversion from total effective porosity to hydrocarbon porosity was made by providing, in the core analysis computer program, an arrangement whereby 0.85 per cent could be automatically subtracted from all measured porosities as reported in the 210 available core analyses. It was unnecessary to assign individual pore volume saturations to each core sample, because, by virtue of the correlation's geometric form, a saturation corresponding to any average effective porosity in *Figure 5* is a true weighted average saturation regardless of the number or type of samples contributing to the average porosity. This was determined to be a general property of Type I and Type II hyperbolas, and is mathematically verified under the heading "Average Saturations from Hyperbolic Correlations."

Weaver, in other investigations, has made a parallel observation regarding the occurrence of constant ϕS relationships. For Archie's rock classification, Type I BCD, he noted (8) that it is only the size and frequency of the connected secondary vugs (and hence the porosity) that controls saturations as long as the dense matrix retains essentially the same character. A combination of mercury injection capillary pressure data and oil-base core data for a "typical Alberta reef reservoir" in northwestern Alberta was presented as an illustration. In two other examples, using only mercury injection data and log calculations to estimate saturations in heterogeneous Mississippian reservoirs, he found no simple inverse relationship between porosity and estimated saturations, although, in one case, the data could be distinctly grouped on porosity-saturation plots constructed for separate rock types. Thus, Weaver's material, although supporting the concept of constant bulk volume water saturations in "homogeneous" vugular carbonates with a dense matrix, provides negative or inconclusive indications in other cases complicated by greater reservoir heterogeneity, possible transition zones and generally less-reliable data.

In 1957, the Texaco Exploration Company filed an MPR submission (9) with the Alberta Oil and Gas Conservation Board which included oil-base core data from a well in the Wizard Lake D-3 reef pool. A previous submission for the neighbouring Bonnie Glen D-3 pool (10) provided oil-base core data showing a similar porosity-saturation trend. Texaco proposed a logarithmic equation of the form $Sw = a\phi^b$ to represent each set of data. The optimum coefficients obtained by the method of least squares (presumably giving equal weight to each data point) were reported to be as follows:

	coefficient "a"	*exponent "b"*
Bonnie Glen D-3	53.65	−0.984
Wizard Lake D-3	78.5	−1.1

It is interesting to note that by averaging the above factors to two significant figures we get: $Sw = 66(1.0/\phi)$, which is the equation of an equilateral hyperbola. This equation is plotted together with all of the combined data for Bonnie Glen and Wizard Lake in *Figure 6*.

It may be noted that the relationship presented in *Figure 6* is essentially similar to the curve derived by Texaco for the Wizard Lake pool. The data in this particular case can be well represented by either logarithmic or hyperbolic curves. From a reservoir engineering standpoint, however, the point of significance extends beyond the fact that a relation-

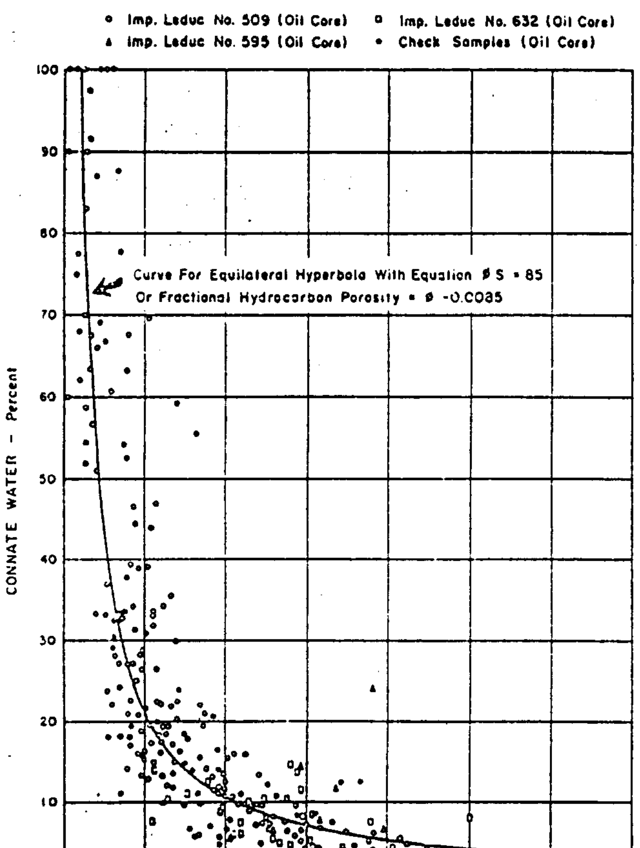

Figure 5.—Saturation-Porosity Relationship of the Leduc-Woodbend D-2 "A" Pool.

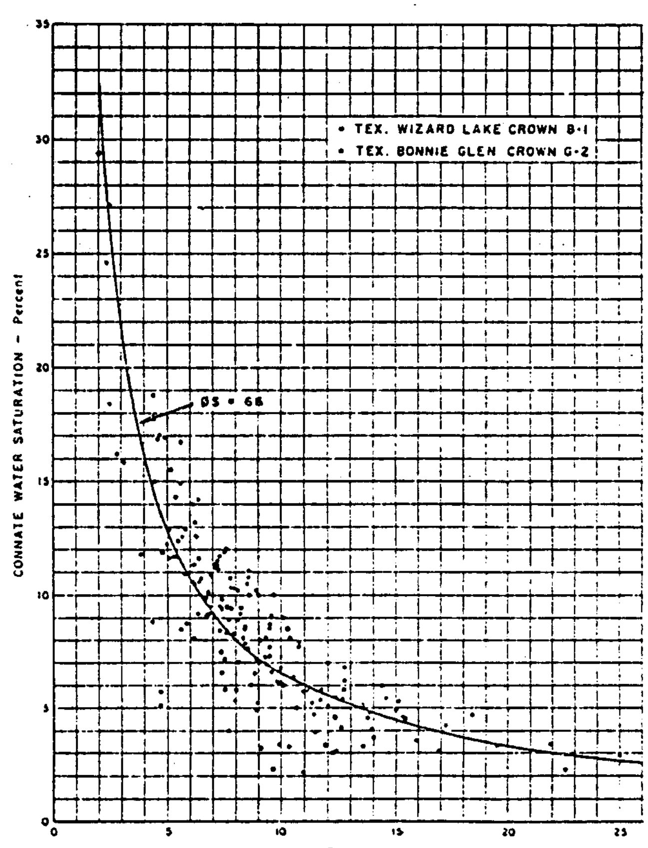

Figure 6.—Oil-Base Core Data from Two Neighbouring D-3 Reefs.

(Adapted from Texaco Exploration Company submissions).

ship of some sort exists. As illustrated in the Leduc D-2 example, and others to follow, it is the consistency and convenience afforded by the hyperbolic relationship in processing and averaging data that is of principal value to the reservoir engineer.

Transitional Saturations and Variable Lithology

One observation which must be made is that a single equilateral hyperbola can hardly be expected to fit data from reservoirs having thick transition zones. In several such cases, ϕS has been found to show a changing trend with depth. Accordingly, any application of the principle under these conditions requires, in effect, a family of saturation versus porosity curves. If each curve is drawn to represent a certain depth interval and if the relationships are hyperbolic, the method will still simplify volumetric calculations to almost as great a degree as when the entire oil zone can be treated as a unit.

Between the two extremes represented by reservoirs with either very long or essentially negligible transition zones* are cases where a single correlation will apply to all but the lowermost portion of the pool. For example, data published by Aufricht and Koepf (11) for a Pennsylvanian dolomite can be plotted to illustrate that, for most of this particular reservoir, an equilateral hyperbola ($S = 220/\phi$) provides a very reasonable correlation. All data for elevations 5 feet above the point of zero water production (14 feet above the bottom of the transition zone) are "on trend" using this function; points for lower elevations fall consistently above the curve and must therefore be considered separately.

Similarly, in reservoirs with variable lithology, selective classification of the data might yield either a family of curves or a single major trend modified by a minority of points corresponding to a significantly different rock type. The Golden Spike South D-3 pool, for example, shows a slightly different porosity-saturation trend for different rock classifications (*Figure 7*). Data for samples described as skeletal and cemented skeletal have been correlated using a hyperbolic function identical to that described earlier for Bonnie Glen and Wizard Lake ($\phi S = 66$). However, *Figure 7* shows that for conglomerate, as well as algal and reef framework material, a better correlation is given by the hyperbola $\phi S = 80$.

*The significance of a transition zone depends more on its size relative to the total oil zone than its absolute thickness (see Case I under "Further Examples."

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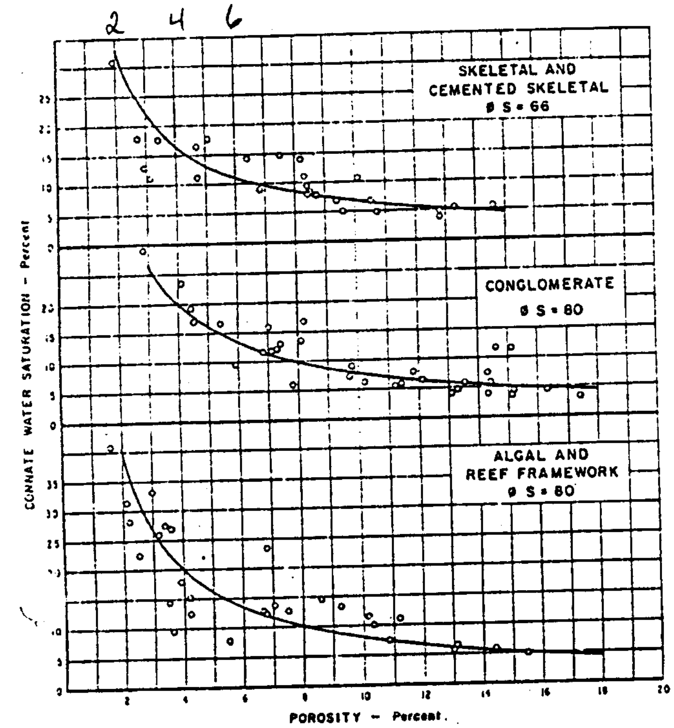

Figure 7.—Connate Water Saturation as Related to Porosity and Rock Type (Golden Spike South D-3).

Statistical Methods

The saturation data generally available may sometimes have a frequency distribution of porosity ranges which is not typical of the entire reservoir. In curve fitting, therefore, statistical analyses of porosity distribution for the reservoir or for its component rock types can be most useful. Mathematical curve-fitting techniques, such as the method of least squares, are highly sensitive to varying concentrations of data points. For that reason, free-hand methods, although more subjective, may be preferred when there has been no effort to obtain a statistically representative group of samples from every porosity range or, alternatively, a quantitative analysis to support the giving of additional or less weight to particular data points.

Complex Hyperbolic Functions

A further general observation stems from the derivation, presented earlier, which showed the effect of having the origin displaced in either the ϕ or S direction. Hyperbolic relationships of the form $(S \pm a) = C/\phi$ — (Type II) or $S = C/(\phi \pm b)$ — (Type III), and the combined form (Type IV), were shown as alternatives to the simple $S = C/\phi$ expression.

The exact nature of the applicable relationship can be readily checked by sketching the straight-line function on reciprocal graph paper. The constant "a", for example, in $S = (1/\phi) \pm a$ can be obtained directly from the intercept on the saturation axis at "infinite" porosity, and $(C \pm a)$ is read where the straight line intercepts the saturation axis at 1.0 per cent porosity.

An example where the form $S = C/\phi + b)$ seems to apply is shown in *Figure 8*. The data points and the curve plotted on cartesian co-ordinates are reproduced directly from a British American Oil Company submission (12) for the Stettler Main D-3 pool. An insert has been added to show the same data points plotted against $(\phi + 1.5)$ on a reciprocal scale. The indicated Type III relationship

$$\left(S = \frac{125}{\phi + 1.5}\right)$$

is virtually identical to the curve presented by B.A. The form $(S-2) = 84/\phi$, however, would be equally valid if less weight were given to points below 2 per cent porosity. This last expression (Type II) has the advantage of providing weighted average saturations for any average porosity directly from the correlation, whereas the other, being a Type III hyperbola, does not.

Average Saturations from Hyperbolic Correlations

Analytically, the equivalence of volumetric average saturations and saturations read from a Type I or Type II hyperbolic correlation at average porosity can be demonstrated as follows:

let $\overline{S}v$ be the volumetrically weighted average connate water saturation;

let $\overline{S}c$ be the correlation's indicated saturation corresponding to the average porosity.

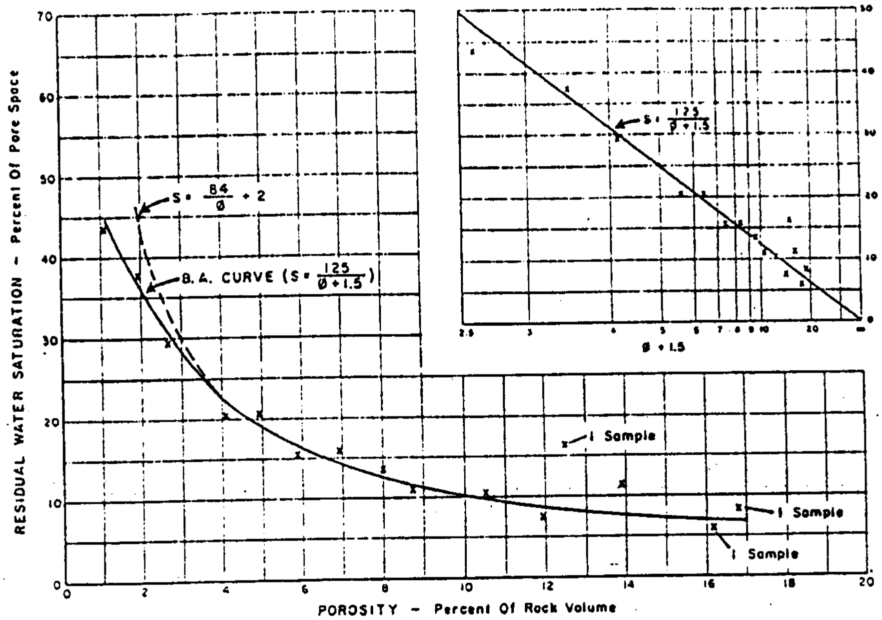

Figure 8.—Porosity vs. Residual Water Saturation Plot — Stettler Main D-3 pool, C.P.R. McCallum No. 4, oil-base core.

(From British American Oil Company submission, April, 1962).

Now, if the interval represented by a given sample is h and saturation varies with porosity according to: $S = C(1/\phi) + a$, where "a" may or may not be zero, then:

$$\bar{S}v = \frac{\Sigma h \phi S}{\Sigma \phi h} = \frac{\Sigma h \phi (C/\phi + a)}{\Sigma \phi h}$$

$$= \frac{\Sigma h C + \Sigma h \phi a}{\Sigma \phi h} = \frac{C \Sigma h + a \Sigma \phi h}{\Sigma \phi h}$$

$$= C(1/\bar{\phi}) + a = \bar{S}c \quad . \; . \; . \; (\text{q.e.d.})$$

Note that using an average porosity to obtain an "average" saturation from non-hyperbolic correlations and hyperbolas of Type III and Type IV does not give $\bar{S}v$, the true weighted average saturation. In certain instances the difference will be small, such as in the Wizard Lake - Bonnie Glen example, where both $S = 78.5\phi^{-1.1}$ and $S = 53.65\phi^{-0.984}$ are roughly similar to the hyperbolic form, $S = 66\phi^{-1.0}$. Another point to be noted is that the "gross" average porosity commonly used in some pools for volumetric calculations must not be used to obtain an average saturation if it is significantly different from the "net" average porosity (see "Further Examples" — Case II).

In practice, where extra terms must be carried in the hyperbolic equation (Types II, III and IV), the advantage of a strictly constant ϕS product is lost. The additional advantage of being able to derive consistent average saturations directly from correlations, however, is lost only when the extra term "b" appears with the major weighting factor — porosity (Types III and IV). Therefore, unless examination shows there is a "b" factor too large to be ignored, saturation data should, wherever possible, be fitted with a Type I or II hyperbolic curve. It is only from such correlations that saturations corresponding to an average of any two or more porosities will be consistent with volumetrically weighted average saturations.

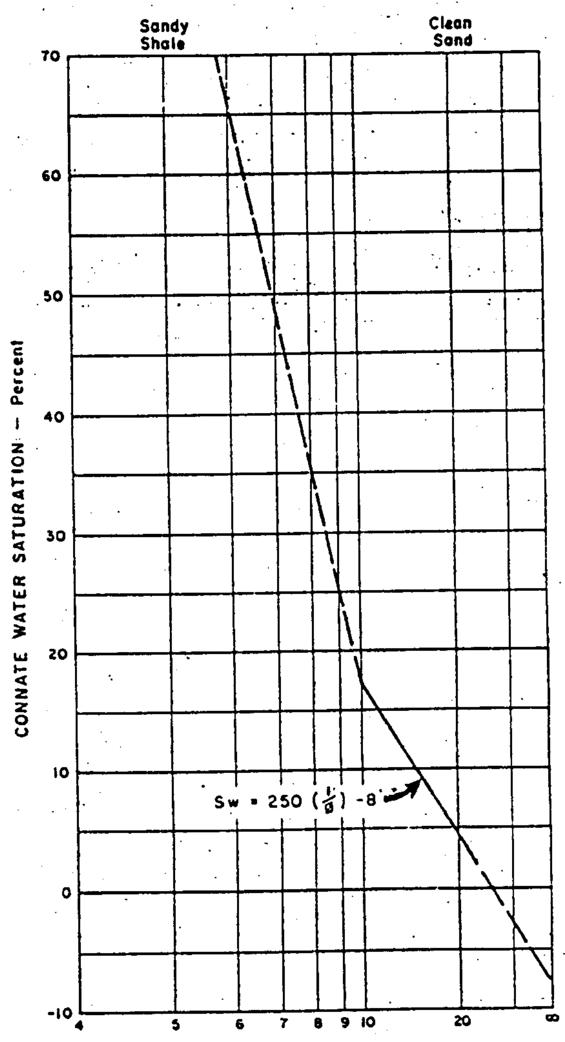

Figure 9.—Porosity - Connate Water Relationsh in the Pembina Cardium Pool.
(Corresponding to Curve "B", Figure 1)

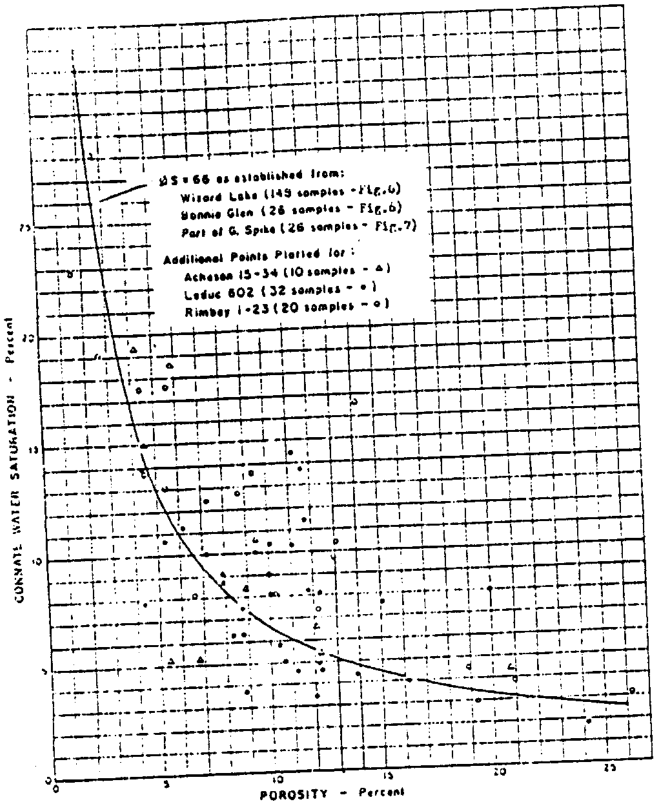

Figure 10.—Correlation of D-3 Oil-Base Core Data from the Leduc Reef Chain of Central Alberta.

By way of illustration, reference is again made to the Pembina Cardium data shown in *Figure 1*. If, in *Figure 1*, the slightly adjusted curve (Curve B) is used to represent the data instead of Curve A, correction factors such as illustrated in *Figure 2* become unnecessary because consistent results are obtained whether saturations are picked from the curve (at average porosity) or are volumetrically weighted. Plotted reciprocally, Curve B is presented again in *Figure 9*. It is interesting to note that extrapolation of the high-porosity trend indicates an intercept at -8 per cent water saturation. ($S = 250(1/\phi) - 8$). Also, a subordinate linear trend is apparent at low porosities (less than 10 per cent). A porosity cut-off to distinguish between reservoir and non-reservoir material is commonly applied to Pembina core analyses. Although there is no universal agreement among operators as to the most suitable cut-off level, figures from 9 to 11 per cent have been found to yield pay thicknesses in good agreement with well-log data. A break in the saturation curve at 10 per cent porosity could therefore be rationalized as a lithology change — from sand or shaly sand to material which is predominantly shale. Operators generally do agree that a permeability cut-off of 0.1 md or greater is applicable in Pembina, and this in turn correlates with porosities at or above the 10 per cent level. Accordingly, the low-porosity portion of the curve can, for all practical purposes, be disregarded and the data can be said to show a single hyperbolic trend for the effective portion of the reservoir.

Once again, the principle to be emphasized is not that a hyperbolic function such as Curve B in *Figure 1* necessarily fits the scattered data points any better than some other relationship such as Curve A; the hyperbola is simply a more consistent and convenient curve to use if accepted as providing an equally valid representation of the data. The average saturation of two 1-foot layers of sand with 24 and 10 per cent porosity, respectively, is found, using Curve B, to be 6.8 per cent, whether volumetrically weighted or picked from the correlation at $\bar{\phi} = 17$. On the other hand, using Curve A, the indicated saturations would be inconsistent. Volumetrically, an average of 9.8 per cent would be obtained, as compared to 7.2 per cent from the correlation at $\bar{\phi} = 17$.

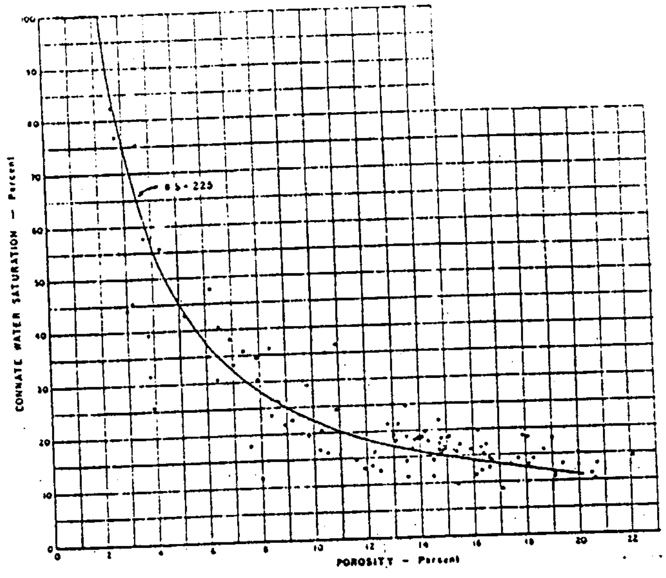

Figure 11.—Oil-Core Data from the Redwater D-3 Reef (Amelia 84, 8-7-58-21 W4M).

Some of the principles discussed above are further illustrated by the following examples:

Further Examples

I.—*Rimbey-Leduc-Acheson D-3 Reef Chain*

The correlation developed for Wizard Lake, Bonnie Glen and Golden Spike data ($\phi S = 66$, *Figures 6* and *7*) has been re-plotted on *Figure 10* and compared with data from various wells along the central Alberta D-3 reef chain from Homeglen Rimbey north through Leduc and Acheson. The curve itself is based on three times as much data as the additional points shown in the Figure. The extra points are reasonably consistent with the established trend.

In using a correlation such as that shown in *Figure 10*, consideration must be given to the estimated size of the transition zone relative to total oil zone thickness. In the D-3 reef pools, transition zones are generally thin, but, in some instances, the oil leg is also relatively thin. Thus, although the average saturation determined from the oil core at Imperial Leduc No. 602 is 7.6 per cent and the saturation corresponding to the average pool porosity is 66/8 = 8.3 per cent, the true average saturation for the Main Leduc pool's 38-foot oil leg, after accounting for higher saturations near the oil-water contact, is about 15 per cent. In Big Lake, another pool on the Central Alberta D-3 reef chain where a similar transition zone thickness likely exists, the indicated 66/11 = 6 per cent pool-average water saturation, as taken from the generalized *Figure 10* correlation, can be applied directly, because any transitional saturations would cover only a negligible fraction of the total 234-foot reef closure.

II.—*Redwater D-3*

The Redwater D-3 pool is separate from the Rimbey-Leduc-Acheson reef family (*Figure 10*), and, as might be expected, it has a distinctly different porosity-saturation relationship. Oil-core data for the Amelia 84 well, as plotted on *Figure 11*, show a fairly good correlation using a Type I hyperbola, ϕS = 225. Restored-state connate water saturation data, however, indicate that at least two hyperbolic correlations, representing different rock types, may provide more realistic results. It should be noted that a net rather than a gross average porosity must be used if a correct average connate water saturation is to be obtained directly from the Redwater correlation, or, for that matter, from any Type I or II correlation. Gross average values, when used with a corresponding gross thickness (dense sections included), are satisfactory for pore volume calculations but not for determining average water saturations. This is because non-effective portions of the reservoir (porosities less than 2.25 per cent in *Figure 11*) are completely water saturated, regardless of porosity, and consequently are not properly represented by any smooth-curve correlation.

III.—*Joffre D-2*

The Joffre D-2 pool is more than 60 miles from the Leduc D-2 pool. Available oil-core data nevertheless indicate that a hyperbolic correlation virtually identical to that shown for Leduc D-2 (ϕS = 85, *Figure 5*) could be used. The relationship actually applied in recent studies of the reservoir is ϕS = 80.

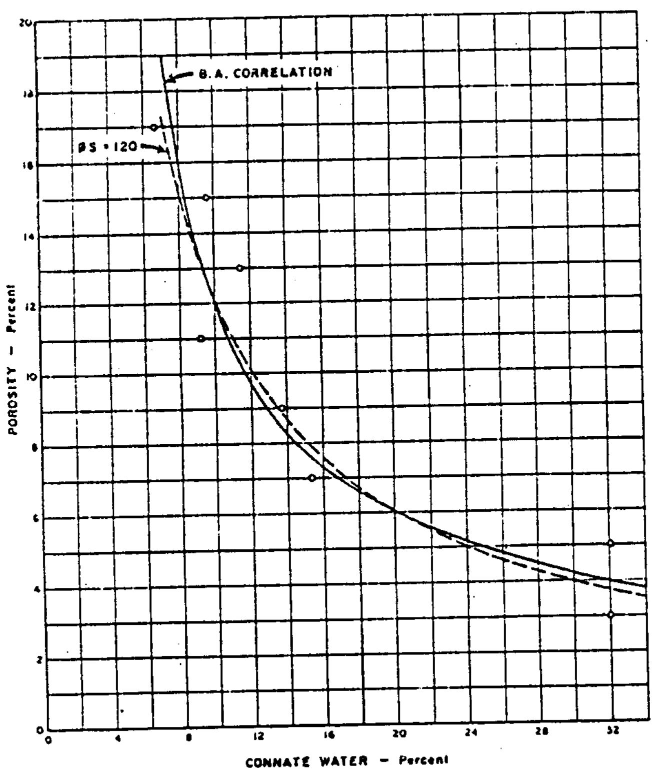

Figure 12.—Connate Water Saturations Based on Oil-Base Core Data from the Fenn - Big Valley D-2 Pool.

(From British American Oil Company submission, September, 1956).

IV.—*Fenn - Big Valley D-2*

In a submission presented before the Alberta Oil and Gas Conservation Board in 1956 (13), the British American Oil Company reported saturation data representing seventy samples from about 85 feet of oil-base core obtained at three locations in the Fenn - Big Valley D-2 pool. Excellent agreement between these data and irreducible saturations determined by the mercury injection and conventional restored-state methods was also reported. *Figure 12* shows the correlation presented in the submission by B.A., together with a hyperbolic curve (ϕS = 120) which is similar and perhaps equally valid.

V.—*Buck Creek Belly River*

Two oil cores were obtained in the small Pembina Buck Creek Belly River "I" pool to provide a cross-check on the exceptionally high apparent water saturation (60 to 70 per cent P.V.). Resulting analyses were in close agreement, as shown on the reciprocal porosity plot of *Figure 13*.

The Belly River (Upper Cretaceous) zone in this pool is of highly variable quality, but is generally described as a medium-grained, poorly sorted chert and quartz sand, containing about 25 per cent silt and clay-size material. Laminations of limey infilled sand, siltstone, carbonaceous shale and coal are common. Low-permeability (below 1.0 md) core samples having less than 12 per cent porosity and showing positive S.P. deflections on the electric log cannot be considered as part of the reservoir and were excluded from the correlation in *Figure 13*. As virtually all of the data above 12 per cent porosity fall between the limiting hyperbolas — ϕS = 1000 and ϕS = 1,500, as shown by the dashed lines on *Figure 13* — it can be said that 10 to 15 per cent of the reservoir's bulk volume is water, 80 to 85 per cent is rock solids and the remainder, less than 10 per cent, is hydrocarbons. The large surface area of the sand evidently holds most of the water in an immobile state, as a third of the wells in the pool consistently produce clean oil.

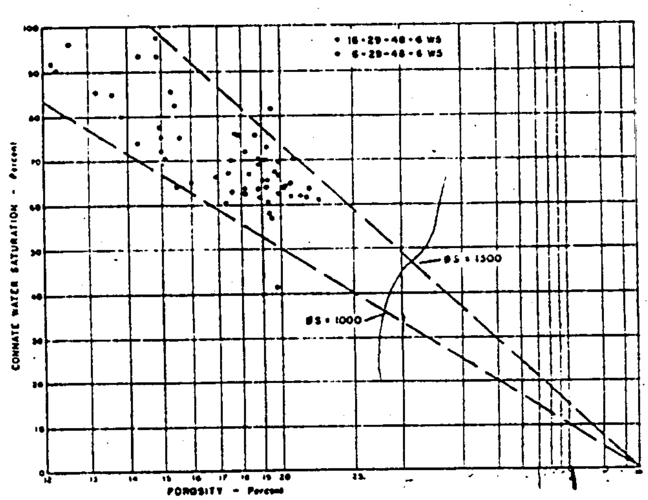

Figure 13.—Oil-Core Data from the Pembina Buck Creek - Belly River I Pool.

VI.—*Provost Viking Sand*

Another example using data from a sandstone reservoir is presented as *Figure 14*. The plotted points represent oil-base core analysis results for four wells in the Provost Viking gas field of east-central Alberta. The hyperbola is of the form referred to as Type IV under "Hyperbolic Relationships," with both porosity and saturation axes displaced from the origin ($S = 265/(\phi - 14) + 14$). As such, it does not offer the advantage of a constant ϕS product, nor does it provide any added convenience in averaging saturation data. The fact that the correlation is hyperbolic is, in this instance, primarily of academic interest. A cursory review of saturation data for two or three other Viking sand pools in Alberta indicates similar complexity. Permeability, in these instances, may be an essential correlating parameter.

VII.—*Ingoldsby Mission Canyon*

In this example, the oil core data have been classified according to whether the samples were from elevations above or below the oil-water contact. As expected, the values plotted for samples from the water zone fall above the curve presented in *Figure 15*, although it is probable that much of the free water was flushed from these samples during coring operations.

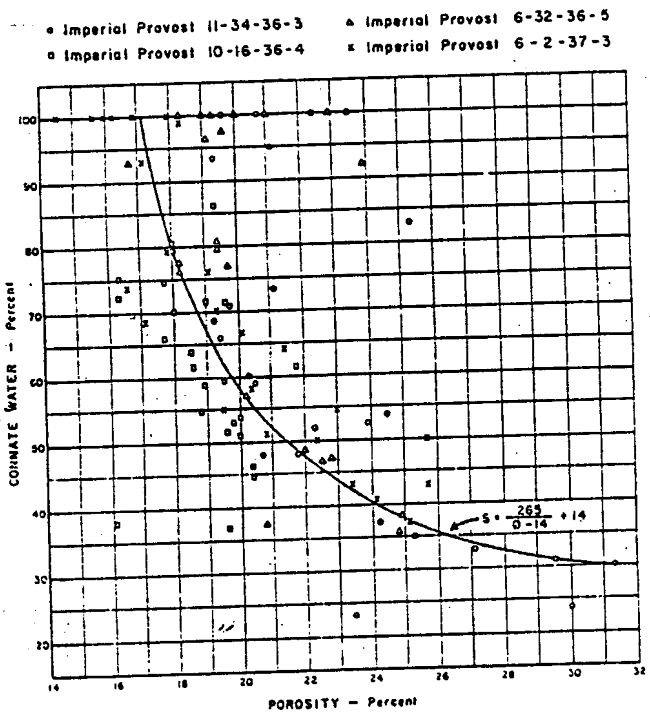

Figure 14.—Connate Water vs. Porosity — Provost sand, Provost Viking gas field.

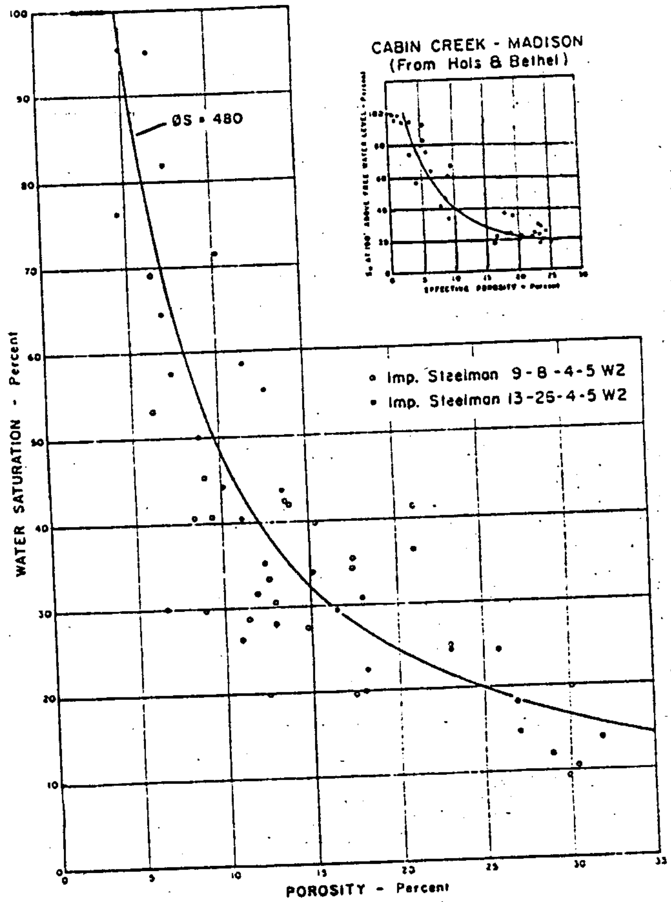

Figure 16.—Connate Water Saturation vs. Porosity. (Steelman Area — Charles Reservoir)

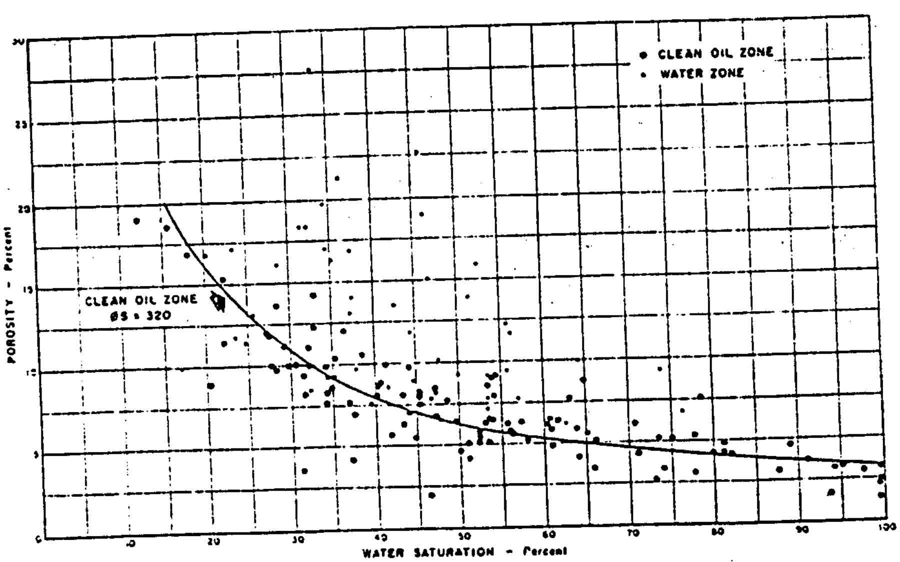

Figure 15.—Porosity and Water Saturation Data — Imperial Ingoldsby 7-7M-41-31.

Different rock types are present in Ingoldsby, but all of the clean oil zone is contained in a vuggy material similar to that encountered at the oil-core location. Using the field average porosity of 10.7 per cent, an average water saturation of 30 per cent is indicated from the relationship. As the curve of *Figure 15* was purposely drawn as an equilateral hyperbola (by trial and error, plotting four or five representative points on reciprocal paper) and a suitable fit was obtained, any saturation read from the curve is immediately known to be equivalent to the volumetric average which would be obtained by more conventional methods.

It is interesting to note that there is an almost complete lack of correlation between connate water saturation and permeability in this Mississippian reservoir. The saturation values themselves are well confirmed by calculations using logs from this and several similar pools along the Mission Canyon sub-crop trend of south-central Saskatchewan.

VIII.—*Steelman Charles*

The producing horizon in the Steelman field of Saskatchewan is a thin limestone bed near the base of the Mississippian Charles formation. Oil-base core data for this fragmental to microgranular carbonate are plotted in *Figure 16*. The equation for the hyperbolic curve shown is $\phi S = 480$.

By striking coincidence, data reported by Hols and Bethel (14) for another Mississippian field in the Williston basin (Cabin Creek, Montana) show an almost identical trend, based on mercury injection capillary pressure data. (See insert, *Figure 16*).

Conclusions

1 . . . .

The choice between using permeability or porosity as a correlating parameter for connate water saturation measurements may, in any particular case, be dictated by the degree of variance and range of data which is apparent. Numerous examples, however, indicate that the use of porosity has particular merit in a variety of carbonate reservoirs and in some heterogeneous sands. The more convenient derivation of representative average saturations favours the porosity correlation whenever the choice is arbitrary.

2 . . . .

Even when the best possible data are obtained, the plotted saturation points generally show a considerable spread and a certain amount of discretion is necessary in curve fitting. Within the limits of reasonable judgment, saturation and porosity data can often be well represented by a simple (Type I) hyperbolic curve. This results in a straight-line trend with a zero saturation intercept on reciprocal graph paper, and signifies a uniform bulk volume distribution of connate water.

3 . . . .

Volumetrically weighted average saturations for any combination of core samples, reservoir strata or lease areas within a pool are obtained with convenience and precision when simple (Types I and II) hyperbolic relationships apply. With Type I correlations, the term ϕ(1-Sw), which is common to all hydrocarbon volume calculations, can be replaced, simply, by (ϕ-constant). Tedious procedures for determining volumetrically weighted average saturations are unnecessary when using either Type I or Type II correlations. More complex hyperbolic correlations (types III and IV) do not offer the same advantages, but their occurrence, as indicated by this investigation, may be less common.

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