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PETROPHYSICAL RELATIONSHIPS FROM THE WESTERN CANADA AREA

by

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ABSTRACT

Log analysis of a number of Western Canada oil and gas reservoirs has yielded sufficient data to establish some petrophysical relationships for use in the area. The solution of the Archie saturation equation illustrates that for each reservoir the degree of oil (gas) zone definition is highly variable. The variability is so marked that individual values of water saturation may only be useful when analogous data is available for reference. In the clay sand or chalky limestone reservoirs of Western Canada water saturation calculations from logs may be of very limited use. Results of travel time-porosity correlations suggest that sandstone travel times are influenced appreciably by cement type and not by depth. The acoustic travel time log is of limited use in the unconsolidated sands of the Western Canada area. Log density-porosity relationships are found to be inconsistent in carbonates but useful in sandstones. Log derived matrix densities are found to be quite different from the theoretical matrix densities for some rocks studied.

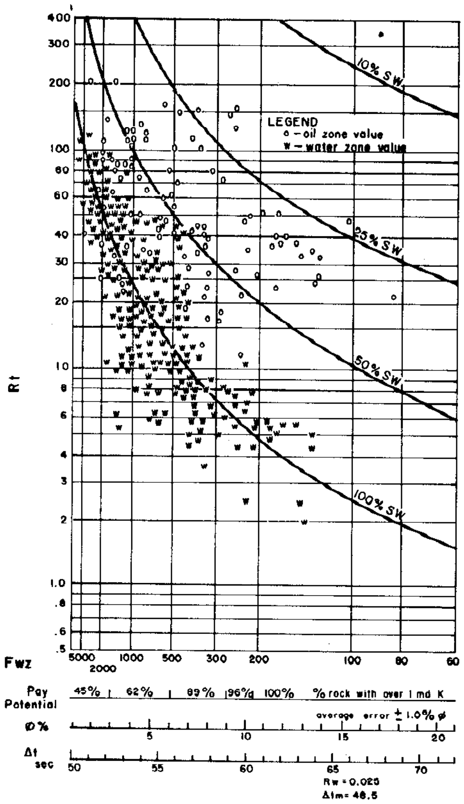
Permeability-porosity relationships appear to be markedly affected by depth in sandstones and controlled by pore system type in carbonates.

INTRODUCTION

This paper is written to discuss the application of certain petrophysical relationships to reservoir rocks in the Western Canada area and to disclose some other petrophysical relationships that have become apparent. The discussion follows a series of field studies of Western Canada reservoirs[1].

The relationship of formation factor and porosity in these reservoirs was discussed earlier[2] as were the log analysis techniques and log-core comparison methods[3]. The main points of the discussion here are the degree of oil (gas) zone definition from logs using the Archie equation, the acoustic travel time-core porosity relationships, the log density-core porosity relationships, and the porosity-permeability relationships encountered.

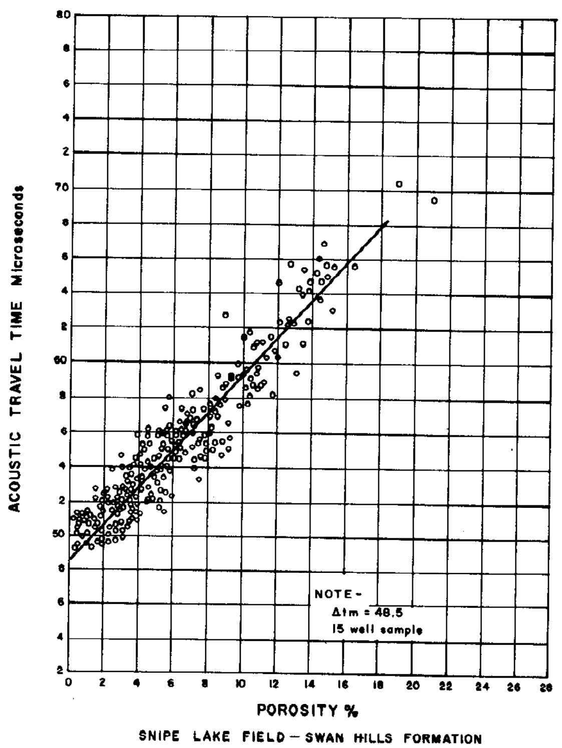
A typical set of data gathered for this study is shown in Figures 1 to 3 which were taken from the Snipe Lake Field, a limestone reef in Central Alberta. Similar charts have been constructed for some twenty-five reservoirs in Western Canada and are the basis of the discussion which follows:



SNIPE LAKE FIELD — SWAN HILLS FORMATION

LOG ANALYSIS CHART

FIGURE 1

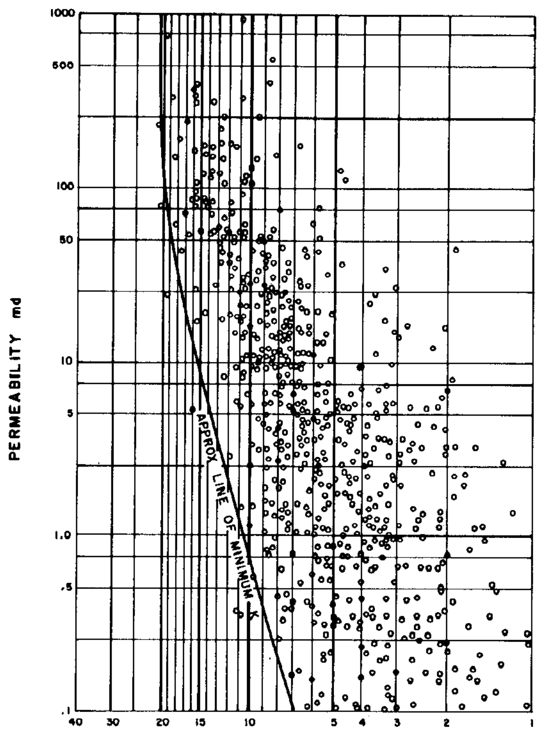


SNIPE LAKE FIELD — SWAN HILLS FORMATION

POROSITY versus ACOUSTIC TRAVEL TIME

FIGURE 2

A



SNIPE LAKE FIELD – SWAN HILLS FORMATION

POROSITY versus PERMEABILITY

FIGURE 3

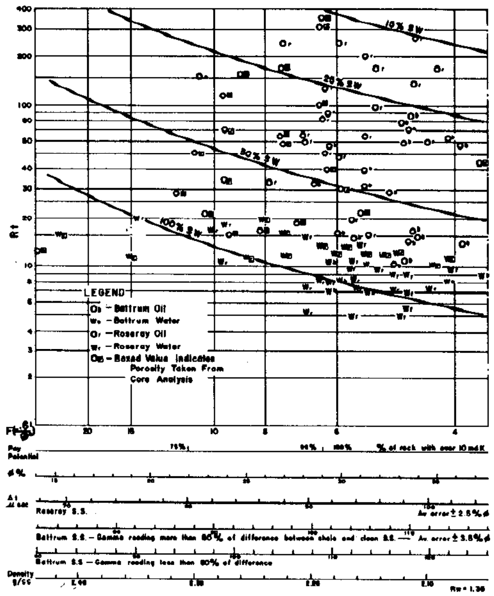
THE DEGREE OF OIL (GAS) ZONE DEFINITION FROM LOGS

Figure 1 and Figures 4 to 17 present composite log analysis charts illustrating the degree of oil (gas) zone definition for some of the reservoirs studied. These charts are constructed using the Archie equation and log resistivity and porosity data.

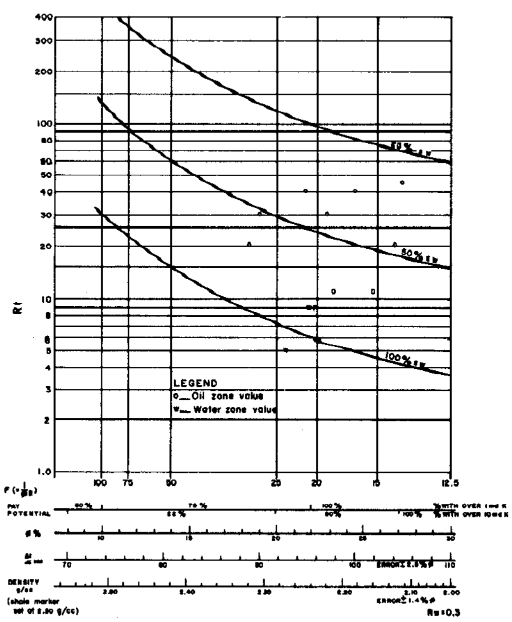
A well defined oil zone is one which is easily distinquished from the associated water zone with well logs using the Archie equation. A poorly defined oil zone is one which has values of log derived water saturation which are indistinquishable from water zone values. The degree of oil (gas) zone definition which is achieved with well logs depends upon the variation in formation factor for a given value of porosity and the success of the porosity measurement, the magnitude of the connate water resistivity, the successful measurement of true formation resistivity, the value of the saturation exponent and the distribution of fluids within the reservoir. The ideal formation for well logging would have a uniform pore system with a predictable formation factor, easily measured Rt, a high saturation exponent, very little low resistivity connate water in the oil zone, and no additional conducting materials such as clay. It is often difficult to anticipate the limitations in the degree of oil (gas) zone definition which simultaneous variations in a number of these parameters might create. These limitations are best discussed by examining results from the reservoirs studied. These results are divided for convenience by rock type into sandstones, limestones and dolomites.

1. Sandstones

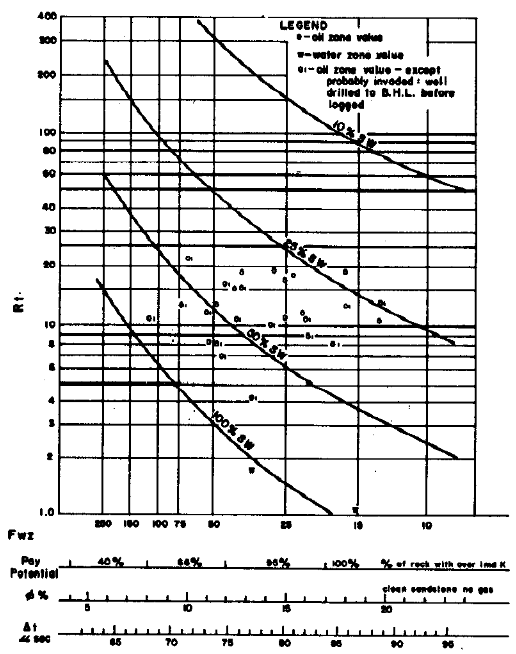
Figures 4 to 10 are charts for sandstone reservoirs with water saturation values plotted on a resistivity-log porosity grid. In each reservoir there are either overlapping values of water saturation calculated for both the oil (gas) and water zone or maximum oil zone saturation values close to the minimum water zone values.



BATTRUM FIELD – BATTRUM and ROSERAY SANDS
LOG ANALYSIS CHART
FIGURE 4

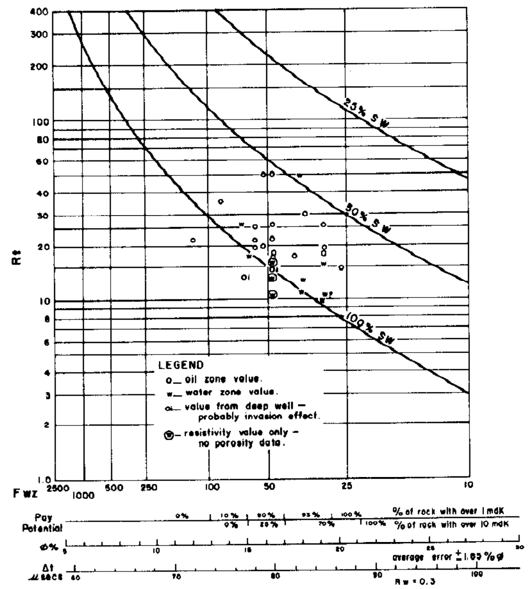


HAMILTON LAKE FIELD – VIKING SAND
LOG ANALYSIS CHART
FIGURE 5



KAYBOB AREA – GETHING SANDSTONE
LOG ANALYSIS CHART
FIGURE 6

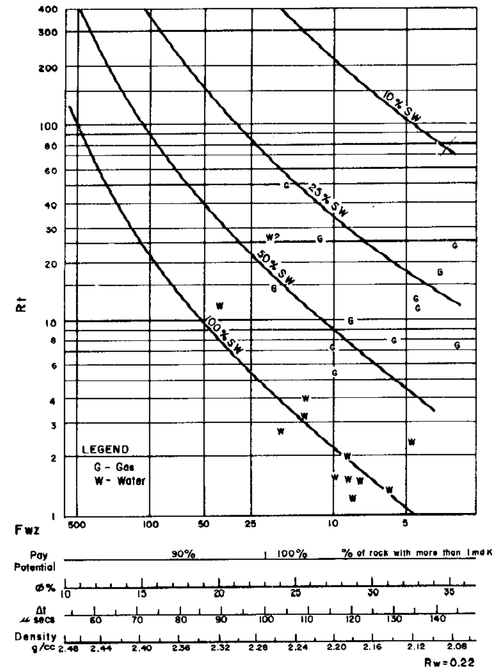
A



KEYSTONE PEMBINA B POOL — BASAL BELLY RIVER FORMATION

LOG ANALYSIS CHART

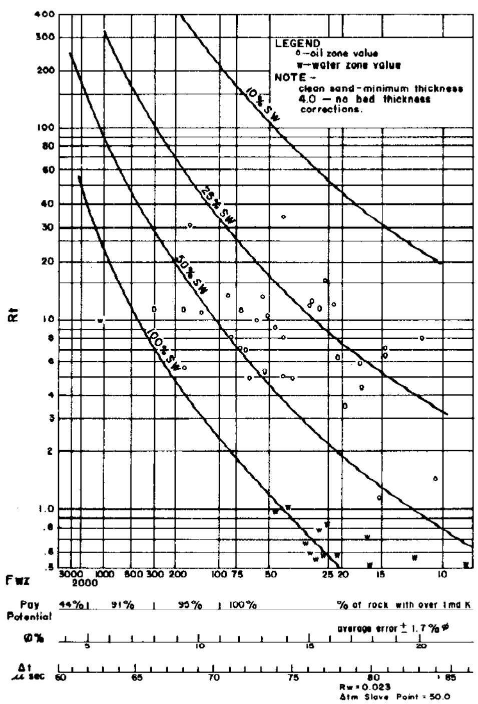
FIGURE 7



LAC LA BICHE AREA — BLAIRMORE SANDS

LOG ANALYSIS CHART

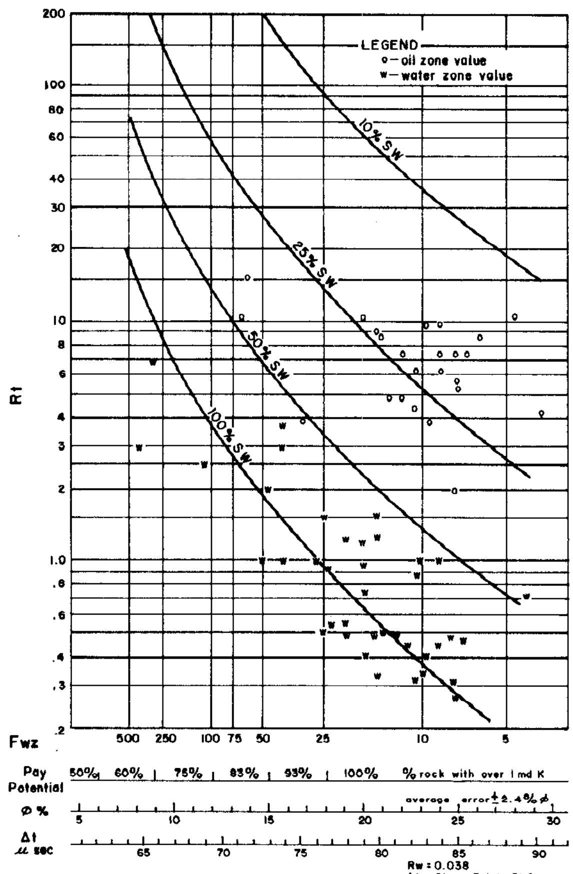
FIGURE 8



MITSUE FIELD — GILWOOD FORMATION

LOG ANALYSIS CHART

FIGURE 9



RED EARTH and UTIKUMA FIELDS — GRANITE WASH SAND

LOG ANALYSIS CHART

FIGURE 10

The separation between oil zone and water zone saturation values or the overlap which is encountered is not predictable. This can be readily seen from Table 1 which details the maximum oil zone and the minimum water zone water saturation values. Some of these values are obviously ridiculous, such as 48% Sw in a water zone or 150% Sw in an oil zone. In fact a value may not be significant but its position on the chart relative to other values is significant. The assessment of formations in this manner, without regard for the specific value of Sw, but with regard for previous experience within the confines of the Archie Equation may be termed the "Analogous Method" of log evaluation.

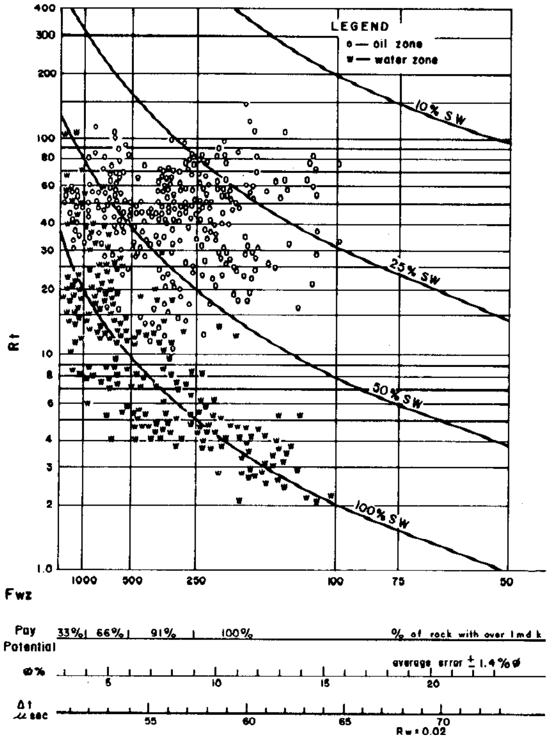
COMPARISON BETWEEN MAXIMUM OIL ZONE and MINIMUM WATER ZONE Sw VALUES IN SANDSTONE RESERVOIRS

FIELD	MAXIMUM OIL ZONE Sw	MINIMUM WATER ZONE Sw
BATTRUM		
Battrum Ss	150 %	80 %
Roseray Ss	70 %	70 %
HAMILTON LAKE	70 %	80 %
KAYBOB	80 %	90 %
KEYSTONE	115 %	48 %
LAC LA BICHE	70 %	70 %
MITSUE	90 %	60 %
RED EARTH	53 %	48 %

TABLE I

It is also apparent that the problem of overlapping values may be restricted to certain porosity ranges as in the case of the Mitsue sand (Figure 9). At Mitsue oil zone calculated water saturation values may be extremely high when porosity is less than ten percent and calculated water saturation values may be too low when porosity is more than seventeen percent.

Despite the particular variations related to each reservoir there is good oil (gas) zone definition in the sandstones with two exceptions. These exceptions are at Battrum and Keystone. In both instances there is an extremely high clay content in the sands. The overlapping values of water saturation in these two instances are very difficult to contend with. An examination of the charts does indicate however that certain combinations of resistivity and porosity can be relied upon to indicate fluid content even in these difficult cases. It is imperative to relate new values for this rock type to the established chart to determine whether the water saturation value indicates oil or water. This is also true for all of the other sandstone reservoirs studied when the calculated water saturation values fall between the previously established minimum water zone value and maximum oil zone value. It is in this system of evaluation by analogy that the most useful application can be made for the Archie Equation.



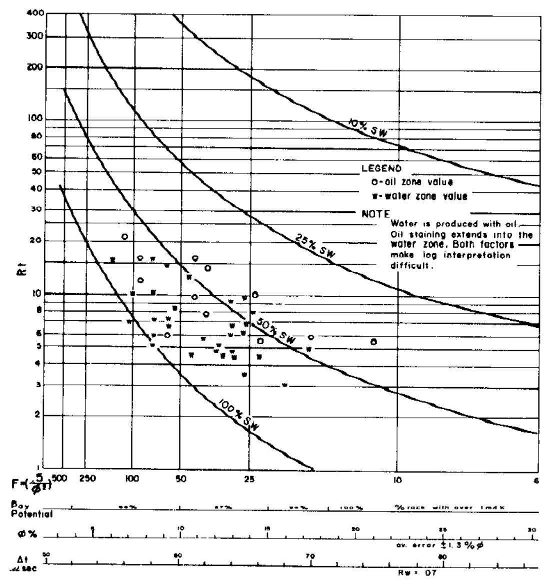
JUDY CREEK FIELD - SWAN HILLS FORMATION

LOG ANALYSIS CHART

FIGURE 11

2. Limestones

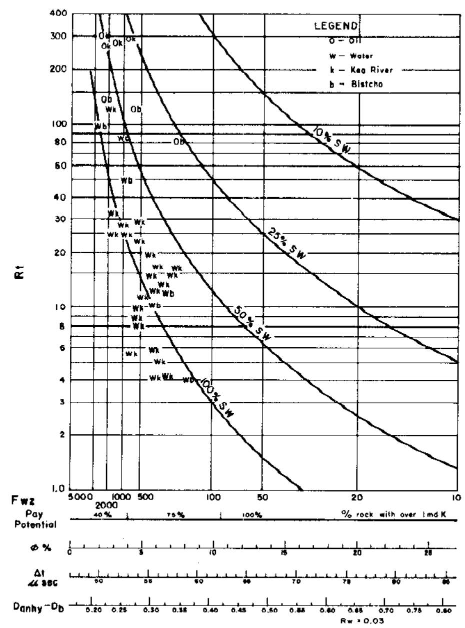
A similar conclusion regarding the use of an analogy can be made from the water saturation data accumulated for limestones. These data are shown in Figure 1 and Figures 11 to 13.



PARKMAN FIELD - TILSTON BEDS (MC-1)

LOG ANALYSIS CHART

FIGURE 12



ZAMA AREA - BISTCHO and KEG RIVER LIMESTONE

LOG ANALYSIS CHART

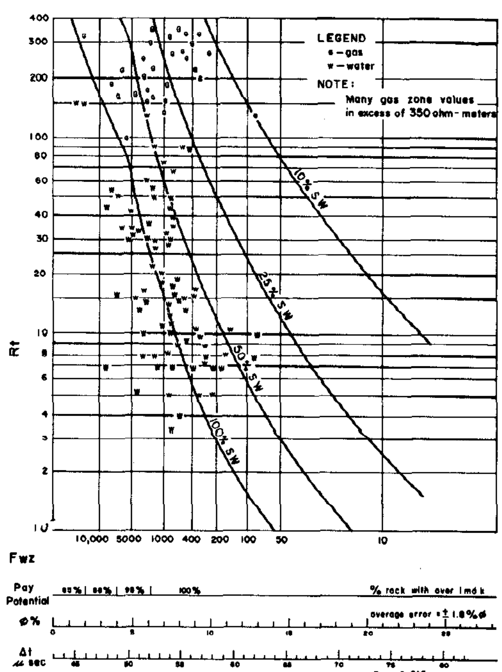
FIGURE 13

Figures 1, 11 and 12 are from reefoid beds and illustrate a typical pattern for carbonates with good oil (gas) zone definition in higher porosities and poor oil (gas) zone definition in low porosities. The specific point of overlap for each reservoir is different and can best be considered in successive log evaluation by using the "Analogous Method" and referring to the original data.

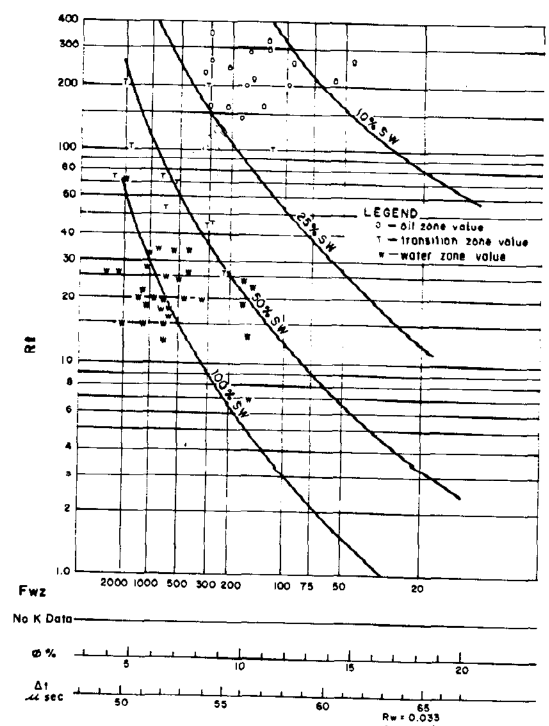
Figure 13 is the log analysis chart for a very fine grained to chalky limestone reservoir. There is nearly complete intermingling of water saturation values from the oil and water zones. Even the use of the "Analogous Method" would not assist in defining an oil zone in this reservoir. Poor oil (gas) zone definition can be expected in chalky limestone reservoirs because of the long transition zones.

3. Dolomites

The degree of oil (gas) zone definition in dolomites is very good and characterized by lower values of water saturation in the oil zone than either the sandstone or limestone reservoirs. This is attributed to the coarse vugular pore systems of the particular dolomite reservoirs presented. Figures 14 to 17 contain the log analysis charts for the dolomite reservoirs.



KAYBOB SOUTH FIELD – SWAN HILLS FORMATION
LOG ANALYSIS CHART
FIGURE 14



MORINVILLE FIELD – LEDUC FORMATION
LOG ANALYSIS CHART
FIGURE 15

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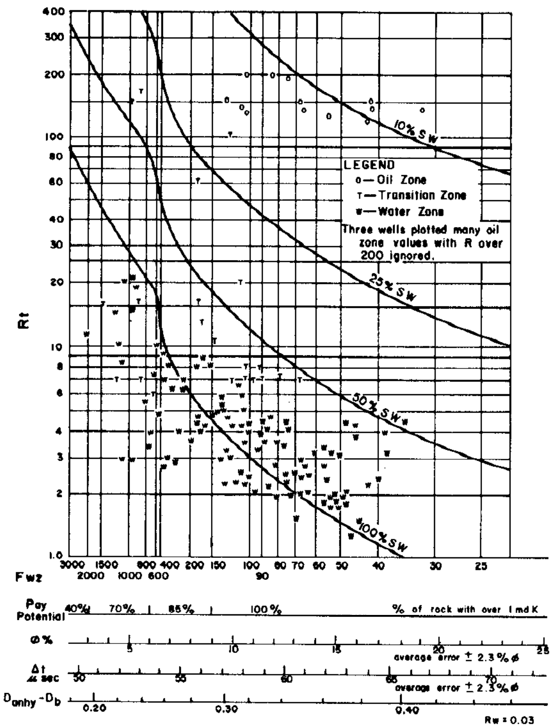
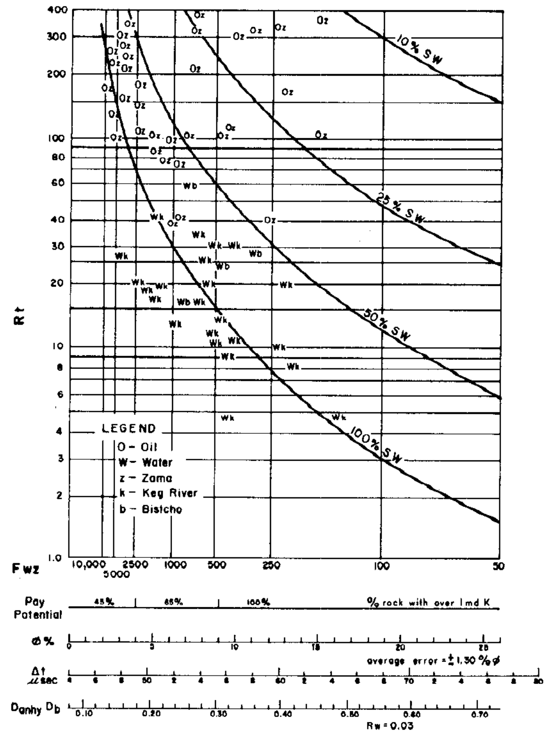


NORTHERN ALBERTA - RAINBOW B POOL KEG RIVER DOLOMITE
LOG ANALYSIS CHART
FIGURE 16

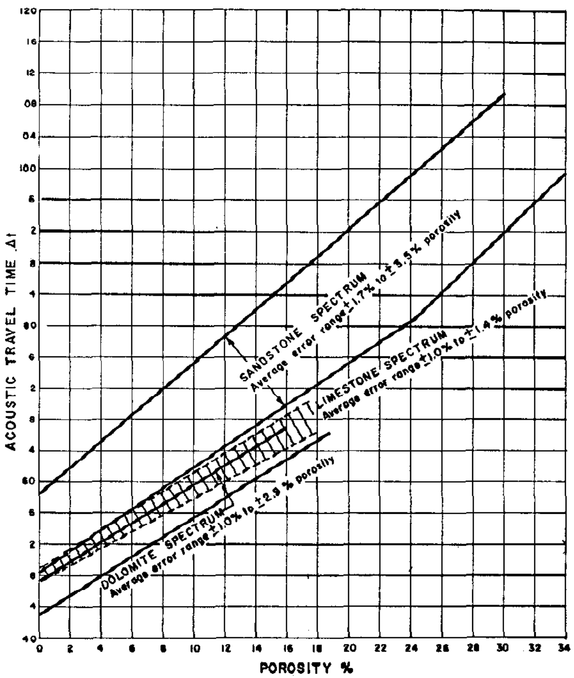


ZAMA AREA - BISTCHO, ZAMA and KEG RIVER DOLOMITE
LOG ANALYSIS CHART
FIGURE 17

In each of these reservoirs whether sandstones, limestones or dolomites, there are distinctive combinations of resistivity and porosity which occur in the oil zone and in the water zone. In order to assess each new combination of values in a particular reservoir it is necessary to relate them to the known data and evaluate their significance by the "Analogous Method".

THE ACOUSTIC TRAVEL TIME-CORE POROSITY RELATIONSHIPS

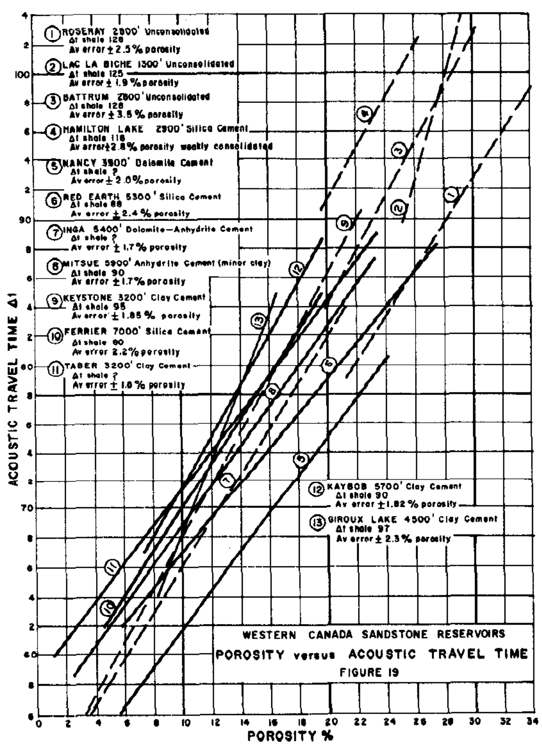
The spectrum of response of acoustic travel time for sandstones, limestones and dolomites, is shown in Figure 18. Matrix travel times for the sandstones examined fluctuate between 48.5 and 58.5 microseconds, for the limestones the fluctuation is between 47.0 and 48.7 microseconds and for the dolomites 43.0 to 47.0 microseconds. These values were found by extrapolation on core porosity-travel time plots. There are some predictable variations within the response range for each rock type, sandstone, limestone and dolomite which are illustrated in the following discussion.



SANDSTONE — LIMESTONE — DOLOMITE
ACOUSTIC RESPONSE SPECTRA—WESTERN CANADA
FIGURE 18

1. Sandstones

Acoustic travel time response in sandstones can be discussed by considering the effects of cement type, depth, consolidation and shaliness. Specific response curves for the sandstone reservoirs studied for this report are shown in Figures 19 and 20. Comments on the effect of cement type, depth and consolation will be made from Figure 19. Shaliness effects will be discussed with reference to Figures 20 and 21.



WESTERN CANADA SANDSTONE RESERVOIRS
POROSITY versus ACOUSTIC TRAVEL TIME
FIGURE 19

i. cement type

The most obvious relationship exhibited by the acoustic travel time versus porosity curves of Figure 19 is the effect of cement type on the consolidated sandstones. There is a shift to shorter travel times for the same porosity value as the dominant cementing material changes from clay to silica to anhydrite to dolomite. The shift can be predicted from the decreasing acoustic travel time values attributed to these cementing materials when they occur as rock units. The rate of change of porosity with acoustic travel time varies between 1.20 and 2.60 microseconds per unit porosity. It also has some cement type dependency with the clay sands having the greatest rate of change of travel time per unit porosity.

The use of general equations related to cement type is warranted for sands although these equations will be much less satisfactory than specific relationships established for specific reservoirs. The following general equations relating porosity and acoustic travel time are suggested for cautious application in sandstones.

Clay cement sands $\phi\% = \frac{\Delta t - 53}{1.7}$

Dolomite cement sands $\phi\% = \frac{\Delta t - 50}{1.4}$

Anhydrite cement sands $\phi\% = \frac{\Delta t - 53}{1.5}$

Silica cement sands $\phi\% = \frac{\Delta t - 55}{1.4}$

where ϕ signifies porosity and Δt is the acoustic travel time in microseconds per foot.

ii. depth

It is necessary to examine sandstones which have the same cementing material in order to appraise the effects of depth on the acoustic travel time-porosity relationship. Four of the reservoirs examined are clay cement sandstones. These are Kaybob at 5700', Keystone at 3200', Girouix Lake at 4500', and Taber at 3200' (Figure 19). The depth effects which might be expected from the results presented by Sarmiento[4] are not apparent. He found a ten microsecond shift to lower values of travel time from 3000' to 5000' in sandstones of Wyoming and Western Canada. The overlapping of the various porosity-travel time curves for the clay sands defies any depth dependency whatever. The clay sands examined do not occur over a wide depth range but the lack of a depth effect can be verified if one projects the Kaybob line (5700') toward the Lac La Biche sandstone line (1300') in Figure 19. There would be overlap with the Kaybob line in the highest travel time values encountered in the unconsolidated Lac La Biche sand. Since the interrelationship of pressure, depth and acoustic travel time are well established by Gardner et al[5], Pickett[6], Sarmiento[4] and Berry[7], there must be other overriding effects to consider. These effects are not revealed by macroscropic examination of the sands in core or by the positions of the various crossplot lines on Figure 19 where the clay cement sands have segregated themselves on one side of the acoustic travel time-porosity spectrum. Further work on the sandstones of Western Canada may reveal the depth effects predicted by other researchers but an objective evaluation of present data indicates that none exist.

iii. consolidation

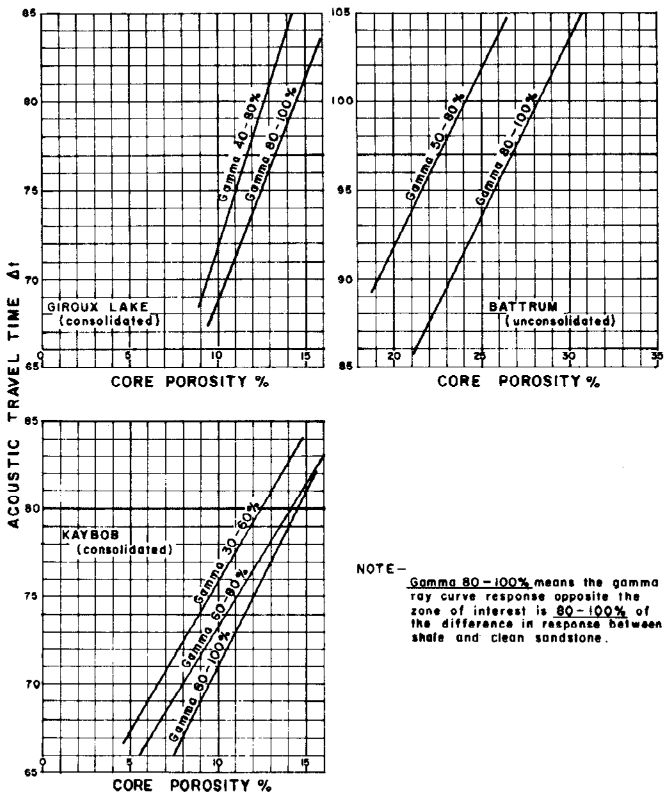
Four reservoirs were examined in which the sands were weakly consolidated or unconsolidated. The best fit lines from the acoustic travel time-porosity plots for these rocks are shown on Figure 19 (dashed lines). Shale travel time values in shales adjacent to the unconsolidated sandstones vary from 118 to 128 microseconds per foot and from 88 to 95 microseconds per foot in shales adjacent to the consolidated sands. The shale value of 118 microseconds was found adjacent to the Hamilton Lake sandstone which is described as weakly consolidated. Some value of shale travel time near 118 microseconds may be considered the upper limit of shale travel time adjacent to consolidated sands. However the data indicates a possible range from 95 to 125 microseconds per foot travel time in shales between sections with consolidated and unconsolidated sands.

The acoustic travel time response in the unconsolidated sands appears to be similar to the response which occurs in the consolidated sands. Higher values of porosity are associated with correspondingly higher values of acoustic travel time. No corrections are needed to allow for the lack of consolidation. The extremely clean quartz sand at Roseray (unconsolidated) has an acoustic travel time-porosity relationship similar to the silica cemented Red Earth sand (consolidated - see Figure 19). Similarly the clay bearing Lac La Biche and Battrum sands (unconsolidated) have acoustic travel time-porosity relationships which place them in the clay sand portion of the sandstone spectrum (see Figure 19). The Hamilton Lake Sandstone is more unique with much longer values of travel time than would be predicted from the data for consolidated sand (Figure 19).

It should also be noted that the average errors in finding porosity with the acoustic travel time log are generally higher in the unconsolidated sands. The Battrum sand (unconsolidated) acoustic travel time-porosity relationship has a huge average error of ± 3.5% porosity. Average errors greater than ± 2.0% porosity are considered very high and average errors of ± 2.5% porosity or more are almost intolerable. Three of the four unconsolidated sandstones examined have average errors of ± 2.5% porosity or more associated with the acoustic travel time-porosity relationships. The relationship is of limited use in these cases.

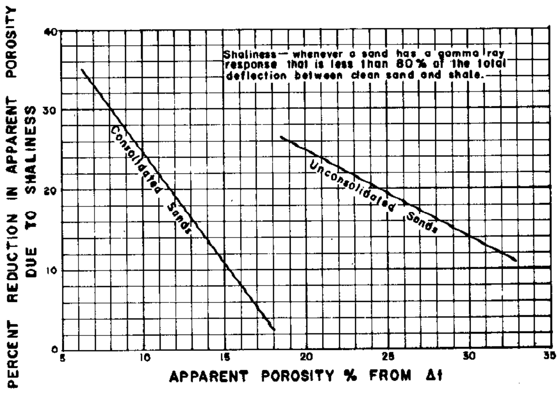
iv. shaliness

The effects of shaliness on the acoustic travel time of sandstones has been illustrated many times previously [4,5,6,7]. The use of the SP has been recommended in these instances to establish a correction for shaliness. The gamma ray curve also responds to shaliness and is used to determine the degree of shaliness for the Western Canada data. Figure 20 presents the acoustic travel time-porosity relationships established for the shaly sands.



EFFECTS of SHALINESS on ACOUSTIC TRAVEL TIME RESPONSE
FIGURE 20

The difference in gamma ray response between a clean sand and shale is used as the norm. A marked decrease in porosity with increased shaliness is apparent for the three reservoirs examined. The Kaybob sands are separated into three groups. Those with a gamma response that is 80% to 100% or 60% to 80% or 30% to 60% of the deflection between clean sand and shale. The amount of correction necessary varies from a reduction of 15% at 15% porosity to a reduction of 40% at 8% porosity. Similarly the Giroux Lake sands are divided into two groups, those with 80% to 100% of the total gamma deflection and those with 40% to 80% of that deflection. In this case a reduction in porosity of 10% to 15% was necessary within a range of 9% to 16% porosity. The Battrum sands are also divided into two groups, one with a gamma response that is 80% to 100% of the total gamma deflection between shale and clean sand and one with a gamma response that is 50% to 80% of that deflection. The amount of correction needed for shaliness varies from 25% to 15% of the porosity value over a range from 20% to 29% porosity. The Battrum sands are unconsolidated and logically require a correction at much higher porosity than the consolidated sands. This data suggests that the amount of reduction in acoustic response due to shaliness can be roughly predicted using the gamma ray curve. Figure 21 is a graph to be used for making shaliness corrections. Shaly sands for the purposes of the graph are those with a gamma ray response less than 80% of the total deflection between clean sand and shale. A further refinement in the shaliness correction is not possible from the data examined.



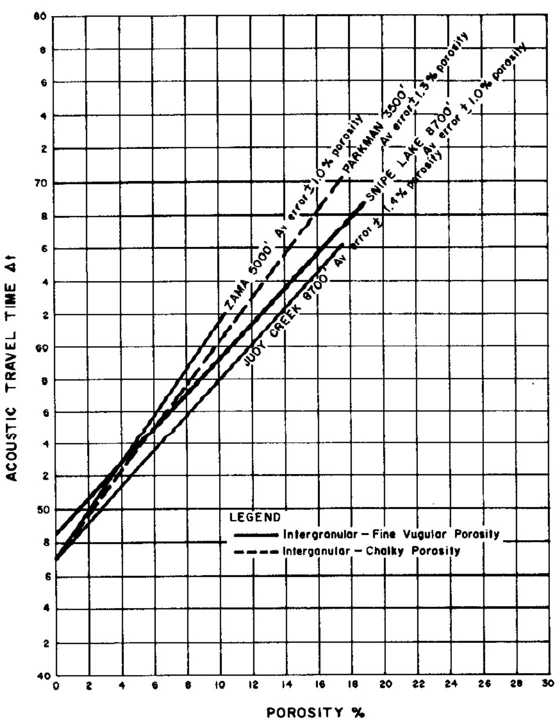
APPROXIMATE SHALINESS CORRECTION to ACOUSTIC TRAVEL TIME FOR WESTERN CANADA SANDSTONES

FIGURE 21

2. Limestones and Dolomites

There is a narrow response spectra for acoustic travel time over all ranges of limestone and dolomite porosity. General equations can be established for each of these rock types with much greater confidence than for sandstones.

Specific acoustic travel time versus porosity curves for the limestones examined are presented in Figure 22.



WESTERN CANADA LIMESTONE RESERVOIRS

POROSITY versus ACOUSTIC TRAVEL TIME

FIGURE 22

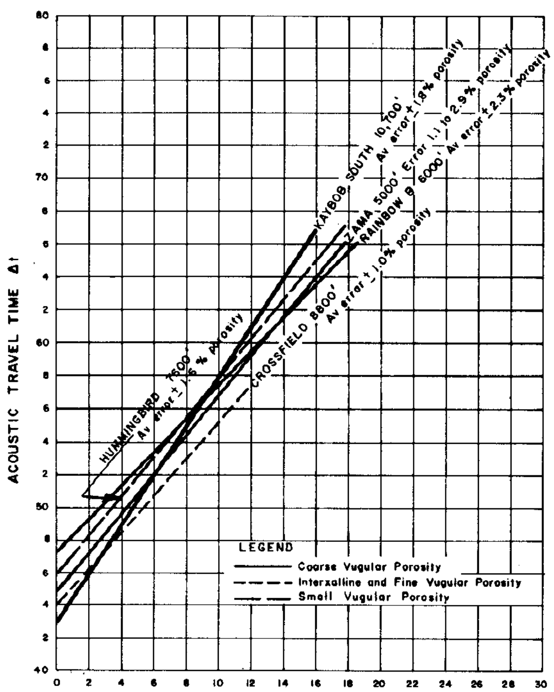
The rate of change of travel time with porosity varies from 1.1 to 1.5 microseconds per foot. The latter value is subject to review since it was derived from a small amount of data and is unusually high. Average errors in porosity determined from the acoustic travel time data for limestones vary from ± 1.0 to ± 1.4% porosity which indicates that the relationships are very useful.

The relationships seem unaffected by changes in pore system as experienced in the Snipe Lake and Judy Creek reefs where intergranular, intrafossil and medium to fine vugular porosity were intermixed.

The following general equation is suggested for limestones:

$$\phi\,\% = \frac{\Delta t - 48}{1.2}$$

The acoustic travel time porosity curves established in dolomite reservoirs are shown in Figure 23. The rate of change of travel time per unit porosity varies between 1.0 and 1.5 microseconds per foot. Higher average errors are encountered in dolomites using the acoustic travel time log than were found in the limestones. The errors vary from ± 1.0% porosity in interxalline and fine vugular porosity to ± 2.9% porosity in coarse vugular porosity. Unpredictable shifts to shorter acoustic travel time values occassionally occur in coarse vugular dolomites and are mainly responsible for the poorer performance of the log in dolomites than in limestones.



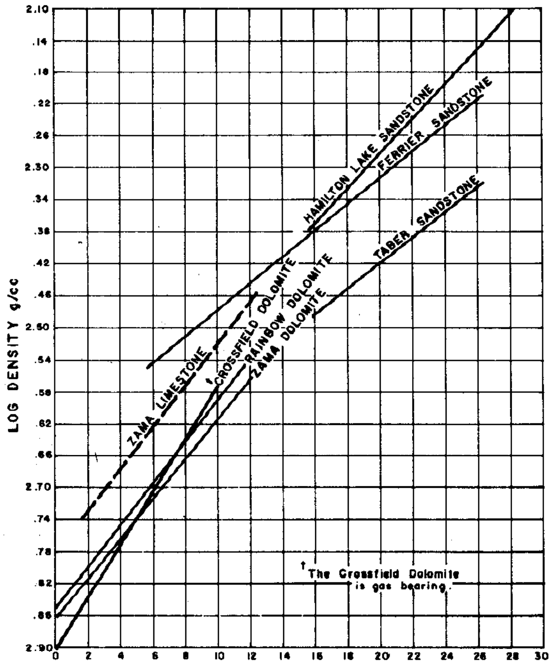
WESTERN CANADA DOLOMITE RESERVOIRS
POROSITY versus ACOUSTIC TRAVEL TIME
FIGURE 23

The following equation is suggested for use in dolomites:

$$\phi\,\% = \frac{\Delta t - 44.5}{1.3}$$

THE LOG DENSITY-CORE POROSITY RELATIONSHIPS

Data is available from seven Western Canada reservoirs for an appraisal of the log density-core porosity relationships in sandstones, limestones and dolomites. The response curve for each reservoir is shown in Figure 24 and discussed below according to rock type.



WESTERN CANADA SANDSTONES and CARBONATES
POROSITY versus DENSITY
FIGURE 24

1. Sandstones

Three sandstone reservoirs are examined, Hamilton Lake, Ferrier and Taber. Each sand has a unique response on the density log. The Hamilton Lake sand has an extrapolated grain density of 2.72 grams per cc and a rate of change of log density of 0.0225 g/cc per unit porosity. The Ferrier sand has an extrapolated grain density of 2.64 g/cc and a rate of change of log density of 0.0170 g/cc per unit porosity. The Taber sand has an extrapolated grain density of 2.74 g/cc with a rate of change of log density of 0.0160 g/cc per unit porosity. These data are shown in Table 2 along with the known grain densities from core analysis.

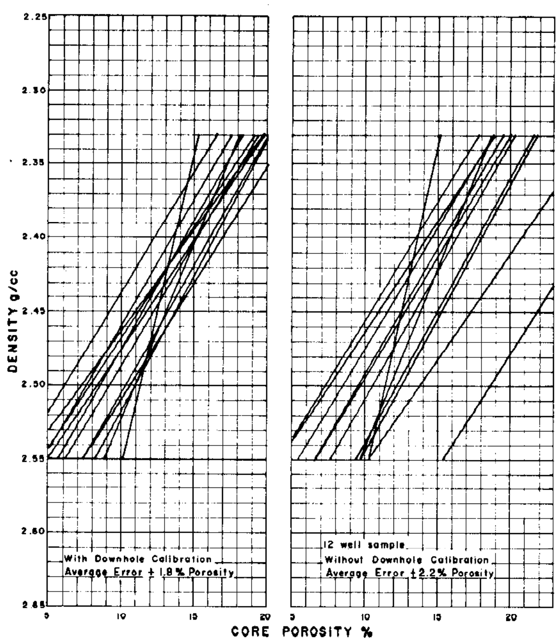
COMPARISON BETWEEN LOG DERIVED and THEORETICAL DENSITY-POROSITY RELATIONSHIPS

ROCK TYPE	APPROXIMATE GRAIN DENSITY	EXPECTED RATIO DENSITY / POROSITY	ACTUAL RATIO LOG DENSITY/POROSITY	EXTRAPOLATED GRAIN DENSITY
FERRIER SANDSTONE	2.66 g/cc	0.0166 g/cc/1%	.0170 g/cc/1%	2.64 g/cc
TABER SANDSTONE	2.64 g/cc	0.0164 g/cc/1%	.0160 g/cc/1%	2.74 g/cc
HAMILTON LAKE SANDSTONE	2.68 g/cc	0.0168 g/cc/1%	.0225 g cc/1%	2.72 g/cc
ZAMA LIMESTONE	2.72 g/cc	0.0172 g/cc/1%	.0170 g/cc/1% .0360 g/cc/1%	2.76 g/cc 2.80 g/cc
ZAMA DOLOMITE	2.87 g/cc	0.0187 g/cc 1%	.0259 g/cc/1%	2.86 g/cc
RAINBOW DOLOMITE	2.87 g/cc	0.0187 g/cc/1%	.0255 g/cc/1%	2.85 g/cc
CROSSFIELD DOLOMITE (gas bearing)	2.87 g/cc	0.0187 g/cc/1%	.0320 g/cc/1%	2.90 g/cc

TABLE 2

A

The Ferrier sand log density-porosity relationship is very near that expected for a rock with a grain density of 2.68 g/cc and a fluid density near 1.0 g/cc. In this case a calibration is applied to the log density data to obtain the agreement and reduce the average error in porosity. Figure 25 illustrates the regrouping of the log density-porosity best fit lines after the calibration to an adjacent sandy shale bed is applied.



FERRIER FIELD - CARDIUM SANDSTONE
IMPROVED LOG DENSITY-POROSITY RELATIONSHIP
WITH DOWNHOLE CALIBRATION
FIGURE 25

Note in Figure 25 the improvement in the average error after calibration from ± 2.2% porosity to ± 1.8% porosity.

A calibration to a nearby sandy shale is also used to organize the Hamilton Lake data but not to fix the grain density value. The extrapolated grain density from the cross plot of 2.72 g/cc does not agree so well with the measured grain density of 2.68 g/cc. The log density-porosity ratio (0.0225 g/cc / 1% porosity) is also unexpected if a fluid density of 1.0 g/cc is assumed. The disagreement in grain densities can be attributed partly to the arbitrary calibration to a sandy shale bed and the line slope shown for Hamilton Lake can be partly attributed to a lighter density pore fluid in this particular reservoir. Neither of these deviations from the accepted density-porosity relationship is predictable. When further data is available from weakly consolidated sands such deviations may demonstrate their predictability.

The log density-porosity ratio for the Taber sand of 0.0160 g/cc per unit porosity is very similar to that obtained for the Ferrier sand and near the expected ratio for a sandstone with a pore fluid density of 1.0 g/cc. However the Taber sandstone log density-porosity comparison results in an unusually high extrapolated grain density of 2.74 g/cc. A macroscopic examination of the sand in core revealed no unusual minerological constituents to account for the high extrapolated grain density. In fact grain density measurements were made on samples from the core and these averaged 2.64 g/cc. Three wells are used to establish the Taber relationship. Comparisons with density logs from other wells in the area reveal a shift to higher density of approximately 0.05 g/cc in two of the wells. It is not possible to compare the third well because the log was only run over a short interval. This shift partly accounts for the high extrapolated grain density of 2.74 g/cc but further unaccountable calibration difficulties must be present.

It is not possible from a study of three sandstone reservoirs to establish empirical density-porosity relationships although certain aspects of the density-porosity relationship are apparent. Firstly, there is fluctuation in density per unit porosity in oil bearing sand reservoirs that is difficult to predict. Secondly, there is fluctuation in the absolute readings from the density log which can be controlled by establishing down hole check beds. Thirdly, and most significantly, the density log responds better to porosity variation in sands than does the acoustic travel time log, provided it is calibrated to that particular sandstone. This third point is illustrated in the following table of average errors.

COMPARISON BETWEEN AVERAGE ERRORS IN LOG POROSITY — DENSITY versus ACOUSTIC

RESERVOIR	AVERAGE ERROR IN POROSITY FROM Δt	AVERAGE ERROR IN POROSITY FROM DENSITY	ROCK DESCRIPTION
FERRIER	±2.2%	±1.8%	Consolidated Ss
HAMILTON LAKE	±2.8%	±1.4%	Weakly Consolidated Ss
TABER	±1.8%	±1.7%	Consolidated Ss

TABLE 3

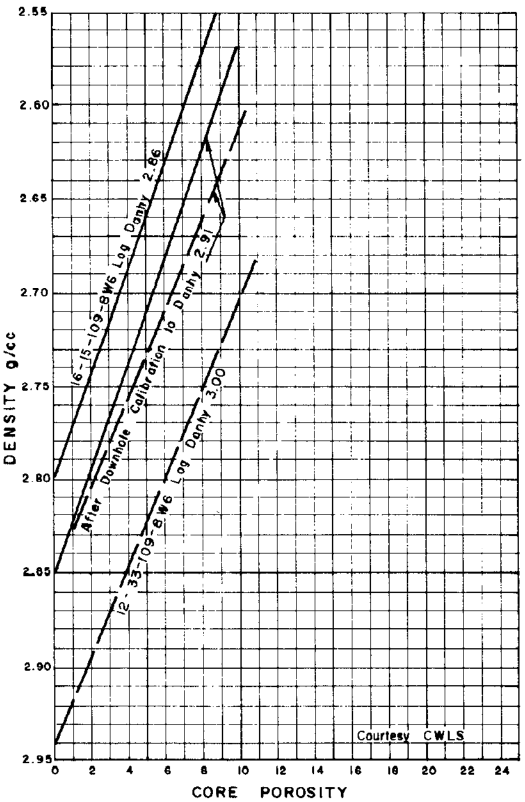
2. Limestones

Density log data for limestones is restricted to two wells in the same reservoir rock. A composite line which best fits the data from the two wells is shown in Figure 24. The relationships established between porosity and log density for the two wells is listed in Table 2. The extrapolated grain densities of 2.76 g/cc and 2.80 g/cc are too high for limestones but not unexpected from the previous discussion of sandstone log density relationships. The rate of change of density per unit porosity is 0.0170 g/cc in the well with an extrapolated grain density of 2.76 g/cc and 0.0360 g/cc in the well with an extrapolated grain density of 2.80 g/cc. The change of 0.0360 g/cc per unit porosity is very peculiar and no mineralogical variations were apparent in the core to explain it. Despite the unexpected log response in these two instances the average errors in determining porosity within each well is very good. The relative response characteristics of the density log are obviously useful but it may be necessary to establish them on a well to well basis in limestones.

3. Dolomites

Data from three dolomite reservoirs are available for an examination of the density log-core porosity relationship . The response curves for these rocks are shown in Figure 24. The Rainbow and Zama reservoirs have high average errors in excess of ± 2.0% porosity. Considerable variation in line slopes and extrapolated grain densities on a well to well basis is found with the Zama data. Both the Rainbow and Zama log data have to be adjusted by using massive anhydrite beds to calibrate the logs downhole. This procedure was discussed in a previous paper[8]. Figure 26 is an example of a successful calibration applied to the log data by using the anhydrite beds. The extrapolated grain densities for the Rainbow and Zama data are very close to the core grain densities (Table 3). The rate of change of log density with porosity is unexpectedly high at 0.0259 g/cc and 0.0255 g/cc per unit porosity. Similar values to these were found in another study of different data from the same reservoir rock by Lishman[9]. The performance of the density log in these dolomites is much less effective than the performance of the acoustic travel time log in carbonates. The acoustic travel time log required much less manipulation and performed much more consistently on a well to well basis.

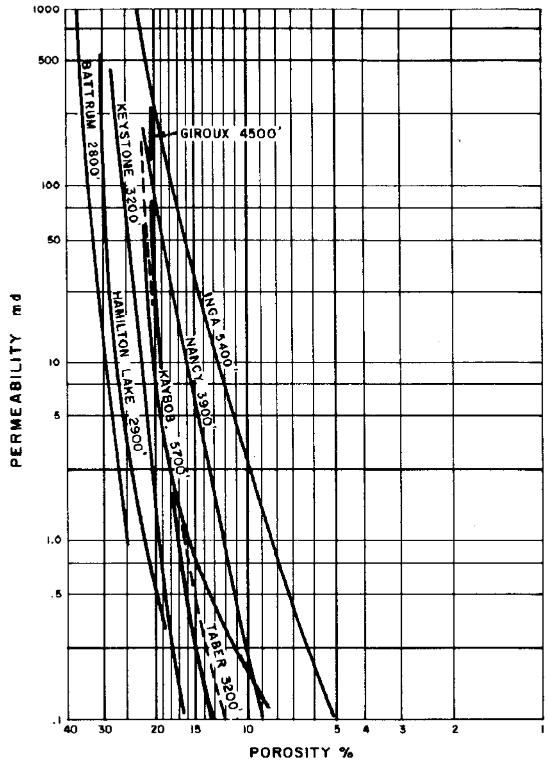
The Crossfield dolomite reservoir has a log density-porosity relationship characterized by an extrapolated grain density of 2.90 g/cc and a rate of change of density of 0.0320 g/cc per unit porosity. The Crossfield reservoir is gas bearing and some of the high rate of change of density can be attributed to that but the value is still much higher than would be expected. The extrapolated grain



KEG RIVER B POOL DOLOMITE

EFFECT OF DOWNHOLE CALIBRATION USING ANHYDRITE ON DENSITY LOG-CORE RELATIONSHIPS

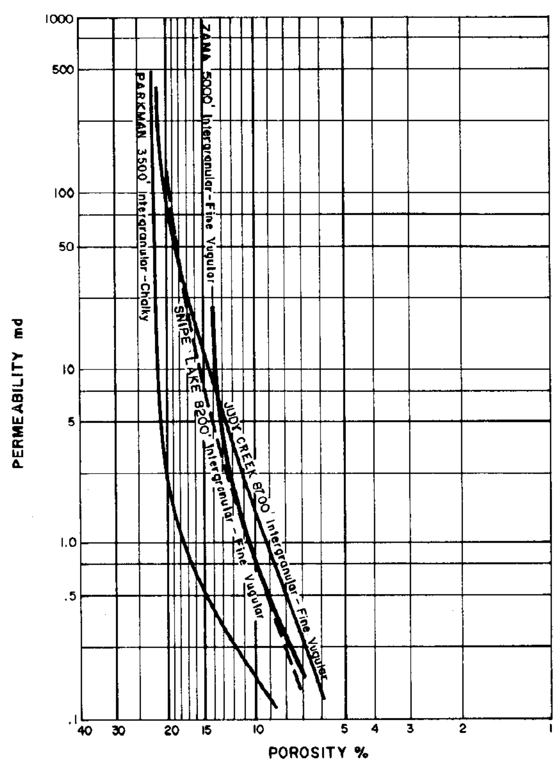
FIGURE 26



WELL SORTED WESTERN CANADA SANDSTONES

LINES of MINIMUM PERMEABILITY

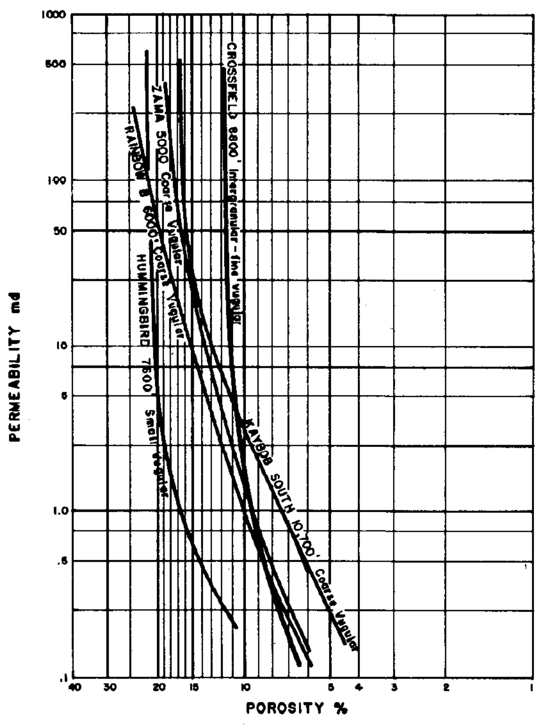
FIGURE 27



WESTERN CANADA LIMESTONES

LINES of MINIMUM PERMEABILITY

FIGURE 28



WESTERN CANADA DOLOMITES

LINES of MINIMUM PERMEABILITY

FIGURE 29

density is close to the actual core value of 2.87 g/cc. There is remarkable similarity in the log density-porosity relationship from well to well at Crossfield as illustrated by the low average error of ± 1.0% porosity.

The inconsistency of the density log data in dolomite and limestone rocks and the need for downhole adjustment of the log data suggests that density logs should be used cautiously as a carbonate porosity device. In the higher porosity sands the inconsistencies are less obvious and can be tolerated.

POROSITY-PERMEABILITY RELATIONSHIPS

The lines of minimum permeability for values of porosity are established for each reservoir rock studied. These lines can be used to establish the porosity value beyond which all of the rock is pay. Figures 27, 28 and 29 present these lines for most of the rocks studied. They are grouped according to rock type, sandstone, limestone or dolomite.

There are many well known factors affecting the porosity-permeability relationship for a particular rock type-pore system combination. In the reservoirs studied it is noted that the sandstone lines of minimum K exhibit a depth dependency with deeper buried sands having higher minimum permeabilities for the same value of porosity. The trend exhibited in Figure 27 is irregular and may be weakened by comparison with more data but the inference can be drawn that better permeability can be expected from deeper buried sands at any given value of porosity.

The lines of minimum permeability for the limestone reservoirs are shown in Figure 28. Note the position of the Parkman line due to the fine intergranular to chalky pore system. Values of permeability in that rock type are much less than in the intergranular and fine vugular pore systems of the other limestone reservoirs.

A similar comparison exists between the small vugular pore system of the Hummingbird dolomite and the coarse vugular or intergranular-fine vugular systems of the other dolomite reservoirs. The small vugular system at Hummingbird is not supported by a significant intergranular pore system and the high porosity-low permeability relationship has resulted.

CONCLUSIONS

The following conclusions regarding the degree of oil (gas) zone definition, acoustic travel time-porosity relationships, log density-porosity relationships and porosity permeability relationships in the Western Canada area are dervied from this study.

1. There is generally good oil (gas) zone definition in sandstones except for some clay bearing sands. In these cases the distinction between oil (gas) and water may be very poor.

2. Oil (gas) zone definition in low porosity limestones is very poor but improves considerably when porosity exceeds approximately eight percent. Noteworthy exceptions to this occur in chalky limestone reservoirs where oil (gas) and water zones may be indistinquishable due mainly to high connate water saturations in the hydrocarbon section.

3. The degree of oil (gas) zone definition in coarse vugular dolomites is very good, due mainly to the low connate water saturations in the hydrocarbon section.

4. In all three rock types, sandstones, limestones and dolomites, there are unpredictable variations in calculated water saturation values in any individual reservoir. Knowledge of these variations is necessary whenever possible to evaluate by analogy the significance of new data within the framework of the Archie equation.

5. Acoustic travel time-porosity relationships are principally affected by cement type. Shaliness also affects acoustic travel time values but no significant change due to depth was noted. Unconsolidated sands could not be evaluated as accurately but for porosity determination the acoustic travel time log appeared to respond similarly in both consolidated and unconsolidated sands.

6. Log density-porosity relationships are more useful for sandstone evaluation than acoustic travel time-porosity relationships although downhole calibration is often necessary.

7. Log density-porosity relationships in carbonates are not as useful as the acoustic travel time-porosity relationships. Inconsistencies in density log response to porosity changes are common and downhole calibration is essential.

8. Porosity-permeability relationships in well sorted sandstones may have a depth dependency in the Western Canada area. The relationship fluctuates with pore system type in carbonates.

9. Sufficient variation in all of the petrophysical relationships discussed point clearly for the need to evaluate by analogy. The most successful method for appraising a reservoir from well logs is by reference to charts calibrated for the particular formation, the "Analogous Method".

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SYMBOLS USED IN TEXT AND FIGURES

Rt	-	true formation resistivity
Sw	-	water saturation
Ø%	-	porosity expressed as a percent
Ø	-	porosity expressed as a decimal
Δt	-	acoustic travel time in microseconds per foot
Δtm	-	value of Δt in matrix or at zero porosity
g/cc	-	grams per cubic centimeter
F	-	formation resistivity factor
Fwz	-	formation resistivity factor calculated from resistivity logs in the water zone
md	-	millidarcy
K	-	permeability
Rw	-	connate water resistivity
Danhy	-	density of anhydrite from log
Db	-	bulk density from log

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