

Formation Evaluation: Carbonate versus Sandstone

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Abstract

The professional geoscientist of today will typically work both sandstone and carbonate provinces, possibly even simultaneously. Many of the wireline tools upon which their efforts and results are based, will be the same in both environments, but the utility and underlying physical meaning of the response, may differ between sandstone and carbonate.

By summarizing the key issues, and how the routine open-hole tools respond and are used, one is able to focus their efforts in a more efficient manner. There are, of course, exceptions to virtually every rule, which is why experience in a specific Field is of such value.

Long experience, with many wells successfully drilled, does not of itself eliminate surprises: Ballay (2001, 2002). In this example, with 120 successful wells (45 of which were cored) drilled, a completely unexpected poor formation was encountered in an area previously drilled. And so one returns to the value of understanding the basics, and being just as alert with well # 121, as when the first well was drilled.

This article summarizes key response attributes and sandstone vs carbonate differences for routine open-hole tools. In a later article we plan to examine specialty tools.

Genesis, Diagenesis and Consequences

The carbonate (ie containing CO_3) environment is typically one that has formed 'in place' via the growth of organisms and / or precipitation. One may also encounter evaporates (halite, anhydrite, gypsum) in association with the more routine limestone (CaCO_3) and dolostone ($\text{CaMg}(\text{CO}_3)_2$).

Sandstones (SiO_2), on the other hand, are typically clastic in origin and consist of fragments of material that were originally deposited elsewhere, broken up and transported via water or wind, and re-deposited. While carbonates can be clastic, that is much less common than the 'in place' origin. In the sandstone world, complications are often associated with 'clay/shale', although other issues (such as feldspar, glauconite) arise in certain provinces.

Clay, silt and shale are the common obstacles present in sandstone formation evaluation. The exact meaning of these terms is sometimes dependent upon location, and context, but a general definition is one of grain size, with shale being a consolidation of both silt ($4 \rightarrow 74 \mu\text{m}$) and clay ($< 4 \mu\text{m}$) sized particles.

Clay usually consists of one (or more) of the following minerals: chlorite, illite, kaolinite and smectite. In contrast to both sand and carbonate, these materials are electrically conductive, and therein lies one of the fundamental distinctions in carbonate vs sandstone formation evaluation: resistivity will be lowered relative to the 'clean sand' value and thereby give rise to a pessimistic S_w (Archie). The presence of clay will also affect the porosity determination, and the composite correction for effects on both porosity and saturation is referred to as The Shaly Sand Problem.

Clay distribution mode, in addition to the volumetric amount, is also an issue - structural, dispersed and laminated – and impacts both the associated electrical circuit and appropriate adjustment to porosity.

Perhaps surprisingly, the question of dispersed or laminated geometry (pore systems) is also an issue with carbonates (Chris Smart, 2005). In a recent Topical Conference the five most common causes of Low Resistivity Pay in Carbonates were ranked as (most → least common):

- Dual porosity system (dispersed large and small pores) with the small pores being water filled while the larger pores are hydrocarbon charged
- Layered formation, in which the large (grainstone, etc) and small (micrite, etc) pore size rock is laminated
- Fractures, which may be oil-filled and present in a (small pore) water filled matrix
- Conductive minerals (rare)
- Incorrect R_t (excessive invasion, etc) measurement (rare)

Sandstones are then clastic in origin with diagenesis typically limited to compaction and cementation. Carbonates, which are more soluble in water, have usually grown in place, and then evolved via cementation, compaction, dolomitization and dissolution (Jerry Lucia, 2004). The importance of dissolution is immediately apparent in the carbonate outcrops, road cuts and caves of the Midwest USA (Figure 1).

Carbonate versus Sandstone

Figure 1

- **Carbonate** - *Diagenesis* includes*dissolution*
- *Surface example of how carbonate reservoir rock can be modified.*



Eureka Springs, Arkansas

In many regards, the key distinction between sand and carbonate, is then one of clay effects versus pore size distribution.

SP and Gamma Ray

Spontaneous potential (SP) is the naturally arising voltage difference between the borehole (at a specific depth) and surface, measured in milli-volts (though it is relative magnitude, and not absolute value, that is important). There will typically be Baseline Drift (which should be removed prior to using the data in a quantitative fashion) and a depth-specific Deflection (voltage potential) that is a function of the difference in R_{mf} (drilling mud filtrate) \leftrightarrow R_w (formation brine), and clay content.

In the case of distinctly different R_{mf} and R_w , and across relatively thick beds, one is often able to use the (baseline straightened) sandstone SP to estimate both $V(\text{Clay})$ throughout, and formation R_w (in the 'clean' intervals).

There is, to our knowledge, no direct, general relation between the magnitude of SP deflection and the actual value of porosity and / or permeability. It's rather a $V(\text{Clay})$ indicator, to be fed into the downstream calculations just as other indicators are.

Carbonates, with their wide range of pore sizes, result in a less well defined SP response, and the SP measurement is not even displayed in many Carbonate Country log suites.

Natural gamma ray activity arises from three sources: ^{40}K and daughter products of ^{232}Th and ^{238}U .

In the clastic world, GR activity is often (but not always) a result of clay, and therefore indicative of a decrease in rock quality. It is for this reason that V(Clay) calculations nearly always include the GR as one estimator (linear as below, or some other functional form).

$$V(\text{Shale}) = (\text{GR} - \text{GR}_{\text{clean}}) / (\text{GR}_{\text{shale}} - \text{GR}_{\text{clean}})$$

Specific clay types have specific relative radioactive components (^{40}K , ^{232}Th , ^{238}U), specific GR activities, and can be identified by means of spectral gamma ray logs.

When faced with variable clay types, or the possibility of additional radioactive components, it's a very good idea to supplement the GR V(Shale) estimates with alternatives from the SP and / or Density - Neutron. For example, we have seen shallow horizon clastic intervals (above the expected pay), logged with only GR / SP / Sonic for which there was very little indication of reservoir quality rock by the GR, yet the SP clearly revealed potential (which was validated with production). And in the cleanest of these intervals, Rw(SP) was in agreement with independently derived values, suggesting that the measurements were valid.

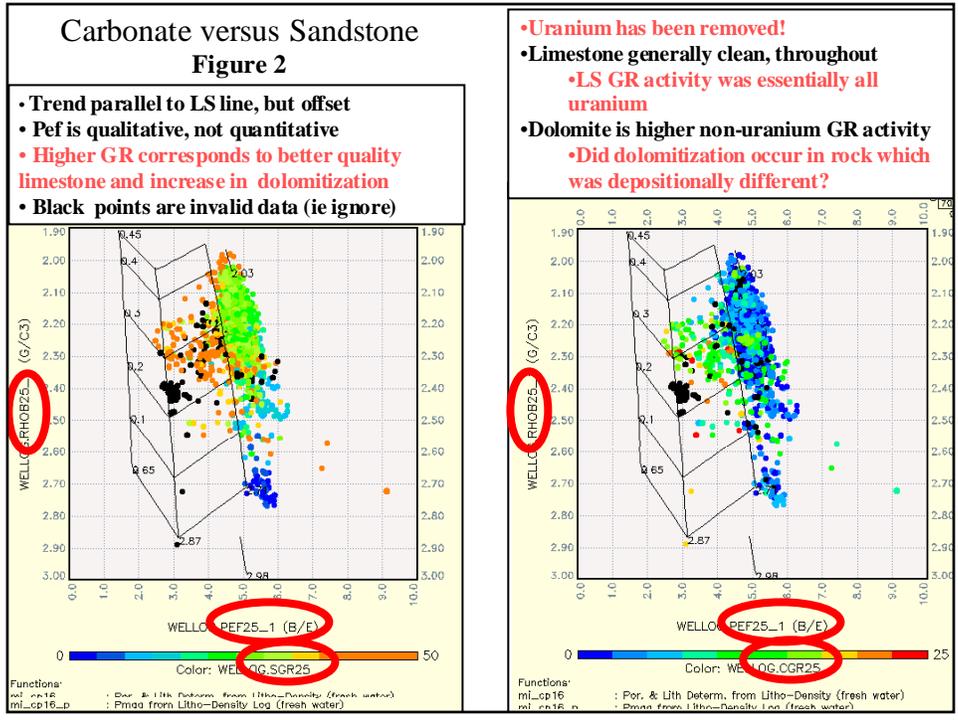
Confusion can arise by failing to clearly distinguish between shale and clay. Bhuyan (1994) found a common error to be the assumption that shales are 100 percent clay whereas in fact shales are commonly composed of 50 to 70 percent clay, 25 to 45 percent silt- and clay-sized quartz, and 5 percent other minerals.

In our experience, there is also a tendency to sometimes regard the rock as being composed of sand – silt – clay, in the absence of any silt compositional information, and in the face of likely (even verifiable) vertical clay compositional variations. We have also found that when the logs are compared to core, a relatively few sedimentary laminations within 'clean' sand bodies, can give rise to log responses that are then interpreted as reflecting a silt interval. One is sometimes (but not always) able to work with the more simple sand – shale model and develop therefrom 3-D geological models that are just as reasonable as the three component results.

A final word about clastics: KCl mud may be used for borehole stability and will shift the GR upwards: the effect must be accounted for if the GR is to be used for V(Clay).

Uranium-bearing minerals are rare but soluble, transported easily and can be precipitated far from their source. In carbonates it's not uncommon to find the GR being driven by uranium, in a fashion that is not necessarily indicative of rock quality. The presence of uranium, and the associated higher GR, can signal

stylolites, fractures, super-perm and / or general increases and decreases, in quality (Figure 2). Spectral GR data is particularly useful in the interpretation of carbonate GR responses.



In today's world of highly deviated wells, for which the tools may be pipe-conveyed, one must also be alert for tool-induced GR response (Ballay 1998). The GR module is typically at the top of the string, and when data is acquired going 'into the hole', particularly at pipe connection time, the GR response will be affected by formation activation associated with the other tools (which precede the GR, in the downwards direction).

Ehrenberg et al (2001) have documented an application of the spectral gamma ray in a Barents Sea carbonate.

In many regards, the key distinction between sand and carbonate, is then the utility and meaning (or lack thereof) of SP / GR response.

Porosity

Sandstone porosity is normally thought of as consisting of Total and Effective, with the two being related by (or something similar)

$$\text{Phi(Effective)} = \text{Phi(Total)} - V(\text{Shale}) * \text{Phi(Shale)}$$

The porosity difference is clay-bound water, which will appear as ‘porosity’ to the logging tools. Since this ‘water’ is in fact immobile, not to be displaced by hydrocarbon, the associated pore volume is referred to as ineffective.

Common porosity estimators are the density, neutron and sonic, used individually, in tandem or all three together.

In some (shaly) sands (Figure 3) the density, by itself, will yield a reasonable estimate of Phi(Total) across concentrations of 0 .LE. V(Shale) .LE. V(Shale) Cutoff and Phi(Total) > Phi Cutoff.

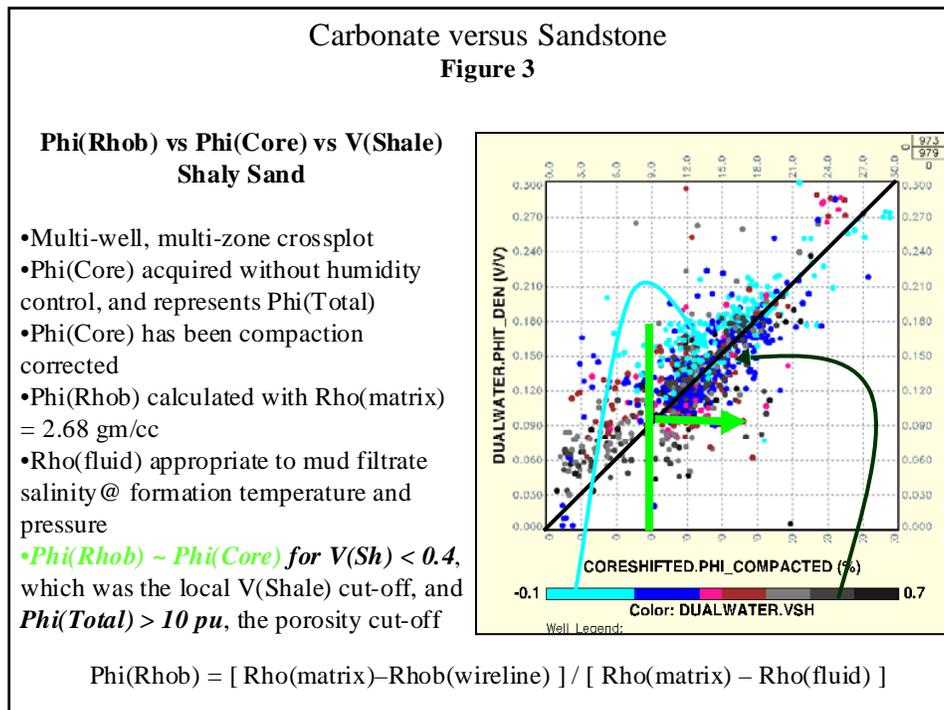


Figure 3 illustrates the situation, which we have found in a variety of provinces.

- The nearly 1,000 core grain density measurements, which include the cleanest to shaliest *cored* (as opposed to the absolute cleanest and shaliest) intervals, peaked strongly at 2.67 – 2.68 gm/cc.
- Phi(Rhob) is calculated from the density log, using the above core-based matrix density and the mud filtrate density adjusted for salinity, temperature and pressure
- Phi(Rhob) correlates with Phi(Core) for V(Shale) less than the local cut-off and for Porosity greater than the local cut-off. Phi(Rhob) is systematically larger than Phi(Core) in the lower porosity rock.
- In this particular case, even the Black (high V(Shale)) Z-axis points are similar to core for Porosity > 10 pu (ie there is agreement in the very shaly points at higher porosities).

This fortuitous event happens because

- Rho(matrix) of sand and shale are locally similar in magnitude (in spite of the significant variations reported in various reference summaries), and/or
- The 'limited range of calibration / applicability' of the method (ie within pay cut-offs) has restricted the evaluation to the domain in which the assumption is valid (which would appear to be the situation in Figure 3).

An alternative porosity estimator is the neutron log, which is subject to many more environmental corrections (than is the density), in addition to experiencing a relatively larger shale effect and potentially large light hydrocarbon suppression. If a valid neutron log is available, the density-neutron combination offers a common solution to the shaly sand porosity problem.

The third routine porosity estimator is the sonic log, which requires no environmental correction, but like the neutron, will often be more sensitive to shale. One should also be aware of the 'adjustments' to the acoustical porosity that may be necessary in 'soft rock' country: sometimes in country that is not thought of as soft rock.

Per the Schlumberger Principles Manual, and observed in our own experience, if the bounding shales have $\Delta t > 100$ us/ft, both of the common porosity transforms (Wyllie and Field Observation) may require a correction factor. Δt (Shale) $\sim 90 \Rightarrow 100$ us/ft may not be thought of as soft rock country, yet we have encountered core – log comparisons which demonstrated the need for the compaction adjustment.

Carbonate porosity (Jerry Lucia, 2004) determination, as contrasted to sandstone, is a completely different issue. Now one is faced with Interparticle (intergrain and intercrystal), and Vuggy porosity. Vuggy porosity is everything that is not interparticle, and includes vugs, molds and fractures. Vugs are divided into separate and touching.

One sometimes encounters the Phi(Total) / Phi(Effective) terminology in the carbonate literature, but the meaning of these terms is now related to irreducible capillary pressure water saturations, and not clay-bound water. For example, Melas et al (1992) define $\text{Phi(Effective)} = \text{Phi(Total)} * (1 - S_{wi})$, in their study of the Smackover.

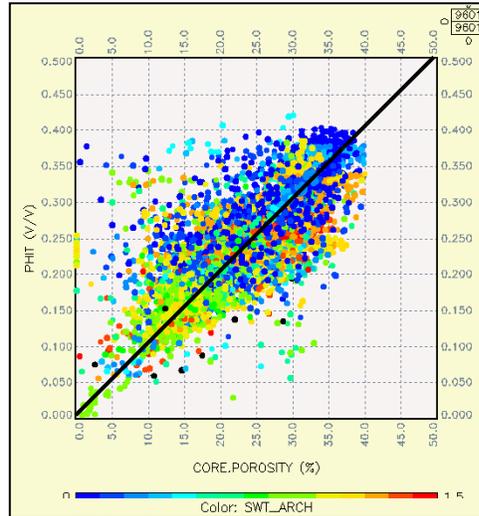
Porosity estimates in the carbonate world must often allow for a mix of minerals - limestone and dolostone with distinctly different grain densities - plus possibly anhydrite and halite. Determination of component percentages now requires multiple measurements and equations: two components require two measurements, etc.

The neutron-density combination is the common tool of choice (Figures 4 and 5)

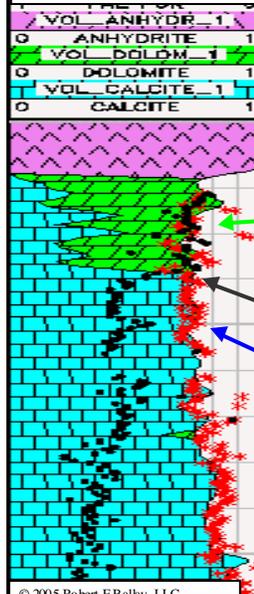
Carbonate versus Sandstone
Figure 4

$\Phi(\text{Rho}_b/\text{NPhi})$ vs $\Phi(\text{Core})$ vs S_w
Carbonate

- Multi-well, multi-zone crossplot
- $\Phi(\text{Core})$ acquired without humidity control, and represents $\Phi(\text{Total})$, but there is no 'shale' issue in this reservoir
- $\Phi(\text{Core})$ has not been compaction corrected, but that factor is relatively small in this 'hard rock country'
- $\Phi(\text{Rho}_b/\text{NPhi}) \sim \Phi(\text{Core})$ across a wide range of S_w (z axis), thereby verifying the absence of light hydrocarbon effects



- Routine Core Porosity
- Routine Core Grain Density
- Wireline Calculations



Carbonate versus Sandstone
Figure 5

Rhog(Core) and Visual Mineralogy
Depth - Rhog(Core) - Anhy - Dol - Lime

Depth	Rhog(Core)	Anhy	Dol	Lime
7426.2002	2.830	-	100.000	-
7426.7002	2.850	-	100.000	-
7427.2002	2.850	-	100.000	-
7427.7002	2.850	-	100.000	-
7428.2002	2.860	-	100.000	-
7428.7002	2.870	-	100.000	-
7429.2002	2.850	-	100.000	-
7435.7002	2.850	-	100.000	-
7436.2002	2.850	-	100.000	-
7436.7002	2.850	-	100.000	-
7437.2002	2.870	-	100.000	-
7437.7002	2.870	-	100.000	-
7438.2002	2.830	-	90.000	10.000
7438.7002	2.790	-	80.000	20.000
7439.2002	2.770	-	70.000	30.000
7439.7002	2.770	-	20.000	80.000
7440.2002	2.720	-	14.998	85.002
7440.7002	2.730	-	10.000	90.000
7441.2002	2.740	-	10.000	90.000
7441.7002	2.730	-	10.000	90.000
7442.2002	2.700	-	15.000	85.000
7442.7002	2.700	-	9.998	90.002

Core vs Log
Mineralogy
Carbonate

- Depth oriented single well display
- Wireline mineralogy varies in accordance with core attributes
- Towards the base of the well, core grain density & porosity are affected by incomplete cleaning & drying)

In Figure 4 the z-axis is annotated with water saturation, as a check for light hydrocarbon effects on the porosity estimate (note that S_w drops to less than 10%).

Light hydrocarbon effects on the porosity estimate are an issue in both sandstones and carbonates, and in both environments we have found

- The density will be less affected than the neutron (common knowledge)
- In single mineral environments, $\Phi(\text{Rho}_b)$ estimated with mud filtrate attributes (ie complete flushing), will match core better than the commonly reported iterative approach (calculate Φ , calculate S_{xo} , calculate weighted average invaded zone fluid density, re-calculate Φ , etc until the Δ Porosity per iteration reaches some pre-set value.)
- Although the iterative correction for light hydrocarbons makes logical sense, it may be that the different vertical resolutions and depths of investigation of the independent measurements that go into the iteration have compromised it. In any case, comparisons to core in both sandstone and carbonate reservoirs have shown that the simpler (assume complete flushing) $\Phi(\text{Rho}_b)$ estimate is a better match. If one wishes to implement iteration, they should consider halting the iteration at some pre-determined point, but prior to convergence, in which case we have been able to achieve matches to core.
- If multiple minerals are present, multiple input measurements will be required and this 'simple' $\Phi(\text{Rho}_b)$ method will not suffice.

In addition to the multiple mineral problem, we have also found LWD Rho_b measurements, just behind the bit, for which the simple (Rho_b) porosity estimate will not be realistic. Now light hydrocarbon effects that would not be nearly so evident with wireline data, which is acquired relatively longer after bit penetration and thereby allows more filtrate invasion to take place, can be apparent. In this case our preference is a probabilistic approach if the software is available.

The need to distinguish between interparticle and vuggy porosity, will require the introduction of an additional independent tool (an additional dimension requires an additional input), and the sonic is often the (routine) tool of choice.

An early documentation of this capability is due to Wyllie (1958), in which he plotted measured dolomite core porosity (intercrystalline, vuggy, fracture) versus compressional transit time, and observed the intercrystalline response to fall along the expected time average equation trend line, whereas the other 'porosity types' were not 'fully seen'.

Conceptually, the radioactive tools respond to all porosity, while the acoustical waves are more pore size dependent. John Rasmus (1983) used a comparison of $\Phi(\text{Rho}_b/\text{Nphi}) - \Phi(\text{Sonic}) - \text{Core}$ to illustrate the effect with actual data.

Anselmetti et al (1999) and Eberli et al (2003) have followed-up on this question to find that "moldic porosity exhibits a range or responses that varies from intercrystalline - interparticle to intraframe".

Jennings et al (2001) summarized the situation as

- Not all deviations from the Wyllie time-average equation are caused by separate-vug porosity
- Not all separate-vug pore space causes deviations from the Wyllie curve
- Careful testing and calibration with core data will be required for each carbonate reservoir

Physically, there is a scattering that takes place in the acoustic waves, similar to that modeled by John Rasmus et al (1985) in the dielectric log: the contrast of dielectric and resistivity responses in rock that ranges from intercrystalline / interparticle to vuggy can be used to characterize the porosity type.

The dielectric will 'see' the vuggy oomoldic porosity more effectively than resistivity, since dielectric response does not depend on pore connectivity, but the contribution is not (initially) 100 % (John Rasmus, 2004) – “The ribs are caused by the "scattering" effect of the inclusions on the electromagnetic wave. There is a similar effect on sonic waves. Alain Brie has shown that the sonic "sees" approximately 20-30% of the inclusions in addition to the intergranular porosity”.

Whether working in the carbonate or sandstone world, it's important to be alert for data integrity issues. In a 41 well carbonate study, drawing upon more than 30,000 core measurements, we (Ballay, 1994) found

- 22 % of the Sonic Logs Required Adjustment (~ 1 pu)
 - This reservoir was generally non-vuggy, interparticle / intercrystalline porosity and pore type did not play a role in the QC
- 51 % of the Density Logs Required Adjustment (~ 1 pu)
 - Constant Shift Usually Sufficient
- 88 % of the Neutron Logs Required Attention
 - Usually small (~ 1 pu) shifts at low porosity, but large (4 - 6 pu in 30 pu rock) in high quality rock. Part of this was light hydrocarbon effect, but the magnitude was far beyond what either of the two sets of Service Company documents would have predicted, and was never explainable in a quantitative manner.

Halite, if present, requires that one be aware of how the density measurement is actually accomplished. Most, but not all, elements have an Atomic Number / Atomic Mass ratio of very close to 2.0. Silicon and Oxygen, for example, are 2.01 and 2.00 respectively. Salt, on the other hand, does not satisfy this ratio and so the wireline-measured bulk density departs from the actual.

Mineral	Actual Density	Tool Density
Quartz	2.654	2.648
Calcite	2.710	2.710
Dolomite	2.850	2.850
Anhydrite	2.960	2.977
Halite	2.165	2.032
Gypsum	2.320	2.351

Courtesy of Schlumberger

In certain areas of the world, anhydrite beds are widespread and referenced for log QC purposes. In doing so, one should realize that 'chicken wire' appearing impurities are not uncommon, are not present in the same concentrations from one well to the next, and can give rise to genuine variations in log response.

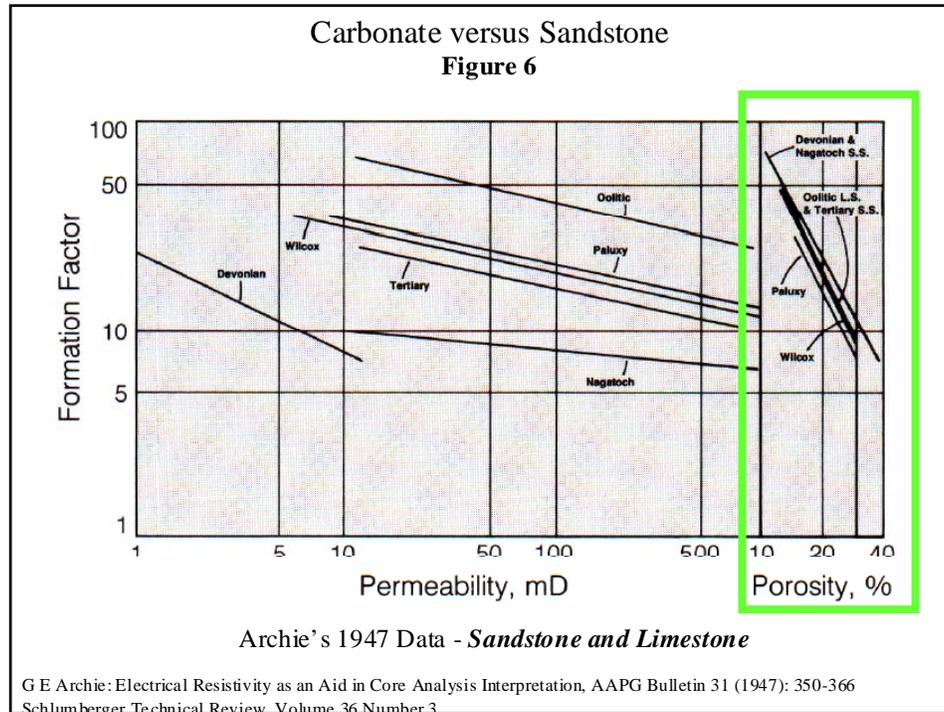
There is, finally, the question of the benchmark for porosity estimation: the core. Although the grain density is typically determined as a part of the lab procedure, it may not be included in the reported tabulations (particularly in the older reports). When included, its usefulness may not be recognized by the interpreter.

The laboratory measured grain density should be used to quality control both the core data and the log interpretations. If the reservoir is known to consist of limestone and dolostone, $\rho_{\text{Hog}}(\text{Core}) < 2.71 \text{ gm/cc}$ should raise a red flag: the core may not have been completely cleaned or dried (Figure 5). Cleaning is an obvious issue in tar but can present a challenge in lighter oils as well. We have also found residual salt, in the core plugs, which shifts the measured grain density downwards.

In many regards, the key distinction between sand and carbonate, is then one of correcting for clay 'porosity' versus allowing for multiple minerals and pore sizes.

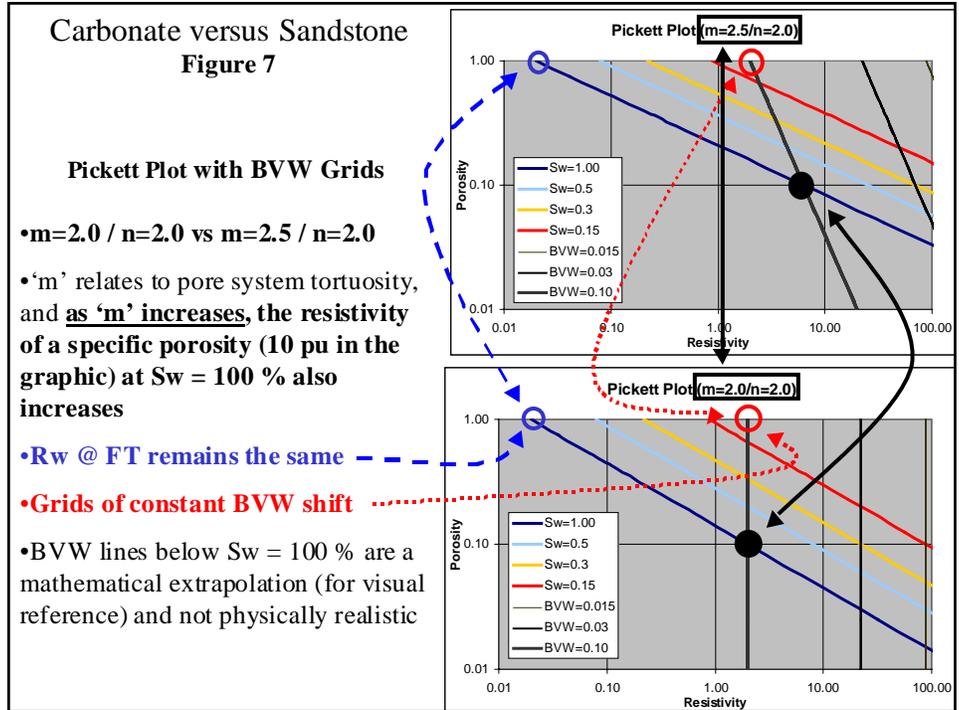
Water Saturation and the Archie Equation

In light of the differences in sandstone and carbonate, per the above discussion, it is perhaps surprising that water saturation can (often) be successfully estimated with the same equation and (similar) parameters (Figure 6).



From this (Figure 6), and similar, measurements Archie (1947) observed that the correlation between Formation Factor (ratio of water saturated rock resistivity to saturating fluid resistivity) and permeability was weaker than that of FF and porosity, which suggested to him that air permeability and ionic (resistivity) flow were 'different'.

Archie's equation, and the impact of variations in the associated parameters, can be visualized with a Pickett Plot (Roberto Aguilera 2002, 2004 and Ross Crain on-line at <http://www.spec2000.net/> and John Doveton on-line at <http://www.kgs.ku.edu/Gemini/>)



Considering, for the moment, 'clean' sand and 'intercrystalline / interparticle carbonates', the cementation exponent reflects the tortuosity of the ionic electrical flow through brine saturated rock. An 'm' of 2.0 is commonly used: smaller values correspond to a less tortuous path, with fractures being a somewhat extreme example. Should the path be 'extra' tortuous, such as when the pore throats are well-cemented, or a portion of the porosity is poorly connected vugs, 'm' will increase.

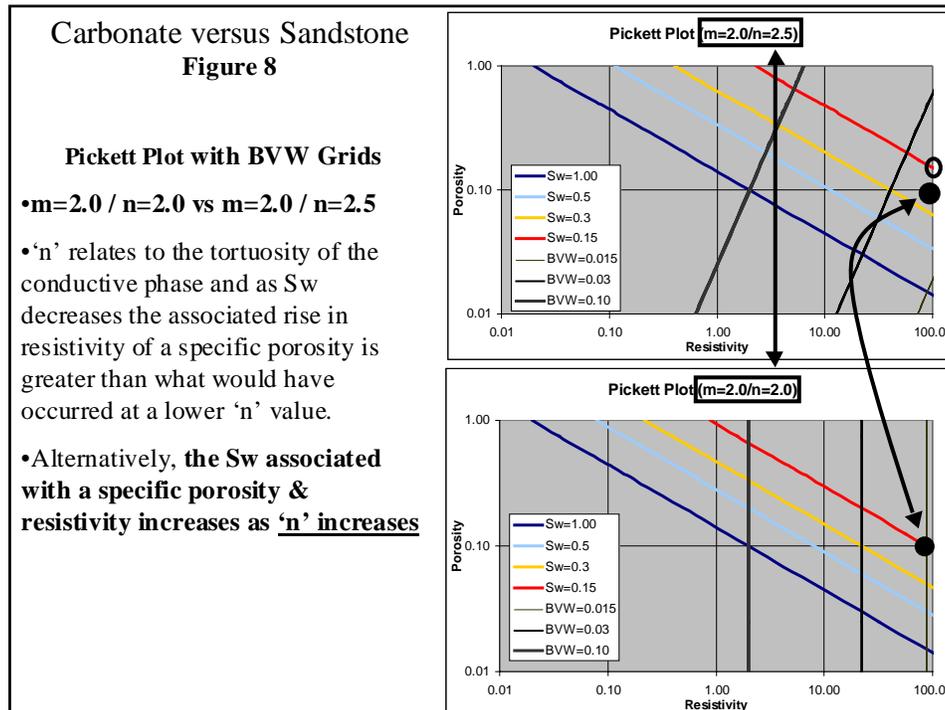
Be aware, however, that small pores, by themselves, don't necessarily mean high 'm': it is the 'effectiveness' of the conduction path.

The cementation exponent of both clean sand and IC/IP carbonates may vary within a relatively short (vertical) distance, and can assume a multitude of values within a given reservoir. This potential must be recognized, in order to avoid consolidating data that is in fact 'different'. These differences may, or may not, correspond to the original depositional environment.

In the words of Jerry Lucia (2004): the foundation of the Lucia petrophysical classification is the concept that pore-size distribution controls permeability and saturation and that pore-size distribution is related to rock fabric. *The focus of this classification is on petrophysical properties and not genesis. To determine the relationships between rock fabric and petrophysical parameters, one must define and classify pore space as it exists today in terms of petrophysical properties.*

By superimposing additional grids on the Pickett Plot, such as a lines of constant Bulk Volume Water, the technique takes on additional meaning. One must remember, however that these grids are also dependent upon the underlying Archie exponents, and will themselves shift just as the Archie grids do.

The saturation exponent, 'n', reflects the tortuosity of ionic electrical flow through the conductive phase, in the presence of a non-conductive (hydrocarbon) phase.



Physically, differences in saturation exponents can reflect wettability, grain surface roughness (Diederix 1982) and possibly other variations. Again, one must heed Jerry Lucia's comments about 'describing the pore system as it exists today, versus the depositional environment'. *We have been faced with laboratory data acquired from a single depositional environment in a single well, measured in the same Lab in the same way at the same time, for which the 'n' varied from 1.5 to 3.0.*

Sandstone evaluation often involves clay and the correction for its contribution to formation conductivity (quartz being non-conductive). The clay distribution mode (dispersed, laminated, structural) determines how the clay and brine conductivities inter-act and what formulation is appropriate for improving saturation estimates.

Laminar shale forms during deposition and is interspersed in otherwise clean sands. Many logging tools lack the vertical resolution to resolve resistivity (and possibly even porosity) values for individual thin beds of sand and shale.

Intervals with dispersed clays are formed during the deposition of individual clay particles or masses of clay. Dispersed clays can also result from post depositional processes, such as burrowing and diagenesis. The size difference between dispersed clay grains and framework grains allows the dispersed clay grains to line or fill the pore throats between framework grains. When clay coats the sand grains, the irreducible water saturation of the formation increases, dramatically lowering resistivity values. If such zones are completed, however, water-free hydrocarbons may be produced.

Structural clays occur when framework grains and fragments of shale or clay, with a grain size equal to or larger than the framework grains are deposited simultaneously. Alternatively, in the case of selective replacement, diagenesis can transform framework grains, like feldspar, into clay. Unlike dispersed clays, structural clays act as framework grains without the dramatic altering of reservoir properties. None (very little) of the pore space is occupied by clay.

Dispersed clay is the most common distribution that we have been faced with (though laminated is certainly a problem in some provinces), and can be addressed with the Dual Water Model, Waxman-Smits, or several other more empirical algorithms (Worthington has authored several nice reviews). The presence of the clay offers an 'alternative' electrical path and thereby compromises the Archie estimates (Archie water saturations will be high). In terms of the Pickett Plot, data points shift to the South West, and so it's good practice to annotate one's Pickett Plot with SP / GR / Rhob-NPhi / etc in the 'z' direction.

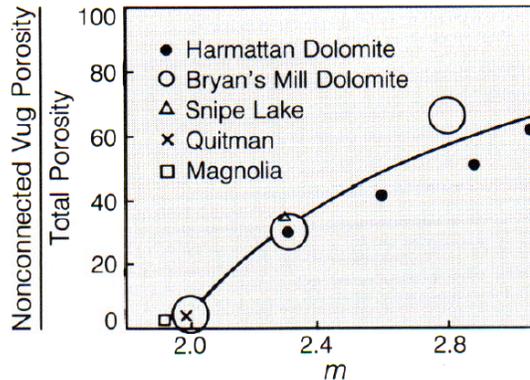
Roberto Aguilera (1990) developed variations of the shaly sand Pickett Plot which offer the option of 'countering' the South West shift of data. He found that all published methods for evaluation of laminar, dispersed and structural clays could be written as $R_t/A_{shale} = a R_w \Phi(\text{effective})^{(-m)} S_w^{(-n)}$ where A_{shale} is model dependent (Indonesian, Dual Water, Waxman Smits, etc.....).

If one then displays R_t/A_{shale} vs $\Phi(\text{effective})$, as compared to measured resistivity vs porosity - Figure 7 & 8, there is a graphical compensation for clay conductivity effects on the resulting (pseudo) Pickett Plot.

As compared to sandstones, the carbonate pore system is less often affected by clay conductivity and one is most commonly faced with variations in the pore size distribution / connectivity (Figure 9 and John Rasmus, 1986)

Carbonate versus Sandstone
Figure 9

- Unconnected *vuggy pore space* vs total porosity
- *$m \sim 2$ for interparticle porosity*
- *$m \sim 3$ for porosity that is 60% vuggy*



F J Lucia: Petrophysical Parameters Estimated from Visual Descriptions of Carbonate Rocks: A Field Classification of Carbonate Pore Space, Journal of Petroleum Technology 35 (1983): 629 - 637
Schlumberger Technical Review, Volume 36 Number 3

Now the Pickett Plot 'z' axis should be annotated with attributes [ϕ (sonic) vs ϕ (R_{hob}/N ϕ i), etc] that will highlight this characteristic, if present. At the extreme, one may need to supplement the porosity – resistivity evaluation with alternative techniques (image logs, dielectric log, pulsed neutron log, nuclear magnetic resonance, etc).

Schlumberger has published, in their Technical Review / Oilfield Review, three articles which provide a more in-depth review of Archie's equation.

- Archie's Law: Electrical Conduction in Clean, Water-bearing Rock. The Technical Review: Volume 36 Number 3
- Archie II: Electrical Conduction in Hydrocarbon-Bearing Rock. The Technical Review: Volume 36 Number 4
- Archie III: Electrical Conduction in Shaly Sands. Oilfield Review: Volume 1 Number 3

In many regards, the key distinction between sand and carbonate, is then one of accounting for clay conductivity 'short circuits' versus variations in pore system tortuosity associated with changes from intercrystalline / interparticle to vuggy porosity.

Three- and Four-Dimensions

Development of a single-well evaluation, even one that involves core, is only the beginning. Formation attributes derived from individual well analyses must fit into the prevailing geologic framework, well to well: the static model.

Time-lapse monitor logs and production data must be understandable within the context of the static model: the fourth dimension.

It's entirely possible that the static model will evolve as more wells, and perhaps routine and special core data, become available, which brings one to an iterative loop (Ballay, 2000).

Some Companies (Petronas, for example) have a policy of re-examining all Fields on a scheduled, rotating basis, taking a fresh look at all (historical and newly acquired, simultaneously) data. In these time-lapse efforts it's important to realize that even the routine tools may yield information that was not extracted the first (or second) time around. Without meaning to discount the value of new, high-tech tools in any way, there are many examples of significant advances resulting from multi-well studies based upon 'routine' tools

In both the sandstone and carbonate worlds, there is tremendous value in multi-well evaluations and time-lapse comparisons, on a re-occurring schedule.

Summary

Evaluation of sandstones and carbonates typically bring different issues to the forefront. As the geoscientist of today moves from one province to another, it's worthwhile to summarize those key differences, and thereby focus one's attention.

This particular contrast has addressed the routine wireline tools. Additional ideas and techniques may be found on-line, at the following links.

<http://www.kgs.ku.edu/Gemini/>
<http://www.spec2000.net/index.htm>

The authors welcome comments and additional perspectives, which may be directed to their e-mail address

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We plan to next address specialty tools, and suggestions / observations / references for that effort would also be appreciated.

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