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Using Wet Shale and Effective Porosity in a Petrophysical Velocity Model
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Abstract

It is well known that sonic logs can be improved by using a petrophysical model to create a theoretical compressional and shear sonic. The measured sonic logs are only used as a guide. There are numerous techniques for doing this, although the most popular are the Xu, White and Keys model (Keys and Xu, Geophysics, 2002) and the Greenberg and Castangna method (Greenberg and Castangna, Geophysical Prospecting, 1992).

These methods and most others require that the subject well be analyzed accurately for porosity, water saturation, and major lithologic and/or mineral components. Using the petrophysical analysis the compressional and shear moduli are built up step by step. First the moduli of the rock mixture are computed, then porosity is added to the mixture and finally the fluids are added using the Gassmann equation (Gassmann, F., Vierteljahrschrift der Naturforschenden Gesellschaft, 1951). The last step is to use the final Gassmann bulk and shear moduli to compute the compressional sonic log and the shear modulus to compute the shear sonic log. Sonic logs containing any fluid mixture can then be computed once this rock framework is built (Batzle and Wang, Geophysics, 1992).

Past experience has shown us that measured sonic logs are subject to serious error due to borehole conditions and invasion. When the results of a petrophysical velocity model are used to compare wells to seismic or to build a rock strength model for pore pressure prediction or a well completion, the results are usually better than with the measured data alone.

The best procedures for building these valuable models have yet to be agreed upon by the industry because the technology is still new. One of the debates is about how to add porosity
and what porosity to use. Many petrophysicists prefer to use total porosity and dry clay volume to build their model. Others, like this author, prefer to use effective porosity and wet shale volume. The reasons behind this choice are presented.

Introduction

Petrophysical velocity modeling, to improve sonic logs and create better well ties to seismic sections, is important today for both AVO studies and seismic inversions. These petrophysical velocity models start with a petrophysical interpretation that describes the rock components. The interpretation provides the volumes of sand, shale, carbonate, etc. in the solid matrix, as well as the porosity of the rock and a description of the fluids filling the rock's pores. Using this description, compressional sonic velocity and shear sonic velocity are computed. Various methods can be used to make these calculations, but regardless of the method used great care must be taken to make sure that the volume definitions used in the petrophysical interpretation are the same as those used in the velocity model. This admonition is particularly important for the definitions of shale and porosity.

Definition of wet shale

Numerous techniques for producing and presenting petrophysical interpretations have been published over the years. All of these methods fall into two categories, the wet shale and effective porosity method and the dry clay and total porosity method. These are described graphically in Figure 1 (slide 2). In both models the total porosity is the same. The "Wet Shale" model, which can also be called a "Rock Model," divides the rock into two components: sand and shale. These are not minerals, but rock components. In this model the shale has bound water associated with it according to a shale porosity determined by the log response in a "type shale" chosen by the analyst. The effective porosity is the porosity that is in excess of the shale porosity("Phish"). The effective porosity portion of the rock has some irreducible water in it, associated with the sand and silt, that depends upon the height above the hydrocarbon water contact or the capillary pressure.

The dry clay and total porosity method shown in the lower half of Figure 1 (slide 2) divides the rock into mineralogic clay (illite, kaolinite, etc.) and quartz and other sand grain forming minerals like feldspars. In this slide only quartz and clay are shown for simplicity. Clay-sized and silt-sized quartz are

lumped in with sand-sized quartz in this model. They are part of the shale in the wet shale model. The clay-bound water computed in this model must be estimated by calculating or assuming a clay mineral composition and the amount of bound water that the particular clays can hold. Then using an assumed or computed grain size distribution an amount of capillary bound water must be computed since the clay bound water will be smaller than the total irreducible water in the rock. This estimate of "capillary bound water" is higher than the amount in the wet shale model in proportion to the amount of clay and silt-sized quartz, feldspar and other sand forming grains.

Both methodologies can work given the appropriate data and interpretation. Neither method is invalid. However, the wet shale model requires less data and results in a more accurate interpretation in most cases because the most important data (volume of shale and shale porosity) are more readily available to the analyst. Figure 2 (slide 3) shows a portion of the top of a reservoir sandstone. The darker streaks are shale and lighter streaks are fine sand. One foot of rock is shown. These streaks of sand and shale are below the resolution of density and resistivity logs so the shale and sand streaks are effectively averaged together. Using normal logs, like the gamma ray and density/neutron, calibrated to core or sidewall core laser particle size measurements, the amount of shale can be computed accurately. The laser particle size distribution of a plug from the core is shown beside the photograph. We have divided sand from shale using the conventional cutoff of 31 microns as shown by the line through the histogram.

Figure 3 (slide 4) shows a portion of a Gulf of Mexico well. Estimates of the clean sand GR (47), the 100% shale GR (100) and 100% shale values for several other logs are written on the log. The point at which these values are taken is selected by the analyst. He looks for a shale that is representative of the shale found in the sandstone being analyzed. In this way the shale is defined down hole, petrophysically, with actual measurements. The all important value of Phish (shale porosity) and the values of compressional and shear interval transit time are measured under the appropriate conditions.

Definition of dry clay
Some petrophysicists prefer to estimate the volume of clay minerals in the rock using logs and core data and then estimating the amount of bound water associated with the clay. This method has some advantages. Clay is responsible for holding most of the shale bound water because of its electrical properties. Most sand and silt grains are composed of the relatively inert quartz, feldspar, and miscellaneous rock fragments. These latter rock components bind to much less water as a percent of pore volume than most clay minerals.

There is a considerable library of research describing the petrophysical properties, especially the CEC or cation exchange capacity, of various clay minerals in the laboratory. Also, by obtaining sidewall cores and performing X-Ray analysis of their fine fraction, the clay minerals in the reservoir sands can be defined fairly accurately. Figure 4 (slide 6) shows a table from X-Ray analysis of two reservoir sandstones

in China. Compare two equations describing effective to total porosity:

<u>Wet shale method</u>
$$PHIT = PHIE + Phish*Vsh$$

<u>Volume of dry clay</u>
$$PHIT = PHIE + Phiclay*Vcl$$

PHIT is the same value in both equations. Vcl (volume of dry clay) is a much smaller number than Vsh, but Phiclay can be quite large compared to Phish depending upon the clay type and its capacity to hold water, its distribution in the rock, and other factors.

It is common in the literature and in practice for some petrophysicists to use the phrase "Volume of clay" or the term Vcl, but actually mean Vsh. So in practice, the wet shale model is often used, while the terminology is from the dry clay model (Xu and White, 1995, equations 2, 3, and 4). This can lead to problems in petrophysical velocity modeling because typically the petrophysical evaluation is done in one computer program and the sonic modeling is done in another. If the values computed in the petrophysical model are in Vclay terms and the values input to the sonic modeling are supposed to be in Vshale terms, considerable errors in the velocity model output are possible.

Comparing the methods
When building a petrophysical velocity model, especially in a loosely consolidated rock, the petrophysicist quickly realizes the importance of the shale. The water bound to the clays and other minerals in the shale provide most of the strength of typical reservoir rocks. Small changes in the volume of shale computed in the petrophysical analysis make a large difference in the velocity model results. Likewise, small changes in the selection of the density of the shale and the sonic interval transit time of the shale make a large difference. For a petrophysicist used to spending most of his time on the reservoir rock and virtually ignoring the shale analysis this can come as quite a shock.

The wet shale method is superior to the dry clay method of petrophysics when the ultimate goal is a petrophysical velocity model because in the wet shale method the critical parameters used in the analysis are selected down hole, near the rocks being modeled. On the other hand rock is very rarely composed of 100% clay minerals; therefore, parameters for the dry clay model can rarely, if ever, be selected down hole. The quantity "Vsh" is not an abstraction like "Vcl" and "Vsh" and has properties that can be measured in a native environment.

An estimate of the percent dry clay and the mineral composition of the dry clay are fairly easily done in the laboratory, but measuring these values in a well bore is very difficult. Look at the list of minerals in Figure 4 (slide 6) again. There are seven minerals in more than trace amounts and three of these are clay minerals. Even more worrisome is

the significant amount of mixed layer illite and smectite. This particular mineral has a substantial variability in its electrical properties (water binding power) depending upon the actual percentage of the two end members present and its distribution in the rock.

To make the estimation of clay-bound water (Phiclay*Vcl) even more difficult the petrophysical and acoustic properties of clay minerals vary with temperature (Bell and Shirley, 1980), pressure (Marion, Nur, and Han, 1992), and salinity. The author doesn't have a reference for the effects of salinity on petrophysical properties, but drilling studies show that the strength of shale in wells is affected by the salinity of the drilling mud. When the strength of the rock changes the acoustic properties and density change.

Computing the acoustic properties

Wally Souder (Souder, 2001) gave a presentation that included a graphical illustration showing the development of a petrophysical velocity model. This illustration, with some minor modifications is shown in Figure 5 (slide 8). The first step is to do a petrophysical interpretation of the well. One needs the volumes of the solid components (e.g. shale and sand) and the volumes of the "in-situ" fluids, like oil and water. The model first computes the acoustic properties of the solid, with no porosity. For the wet shale method, this includes the shale bound water. Next the effective porosity is added to make the "dry frame." The dry frame includes porosity, but no fluids. Finally, fluid is added. Various fluids can be added as needed. The two most important fluid additions are the in-situ fluids and an addition of brine only. In-situ fluids are the interpreted (using an Sw calculation) volumes of water and hydrocarbon.

The details of the calculations will not be discussed here as they are well covered in the literature. However, they are quite complex and unfortunately mathematical errors and typos do exist in some of the publications that can cause problems. Discussions of some of the errors in earlier publications can be found in Keys and Xu, 2002 and in Leiknes, Nordahl, and Pederson, 1999. Further, opinions about the best computational techniques are diverse. We tried several methods before settling on our current methodology.

Currently, we use the Hill Average (Mavko, et. al., 1998, p. 114) to compute the solid bulk modulus. Effective porosity is added to the solid bulk and shear moduli using an approximation to the Kuster-Toksoz algorithm (Kuster and Toksoz, 1974) developed by Keys and Xu, 2002. Fluids are added to the moduli using the Gassmann equation (Gassmann, 1951) as described in Keys and Xu, 2002.

Fluid acoustic properties are computed using the equations in Batzle and Wang, 1992. The fluids are normally mixed using a Reuss average (Mavko, et. al., 1998, p. 111), but in thin-bedded situations the Hill average should be used. All density computations are performed with a volumetric sum as described in Mavko, et.al. 1998 (p. 251).

In order to compute the porosity of the shale ("Phish" from the equation above) the same matrix density used for the non-shale portion of the rock is used. This means that 2.65 is normally used to compute Phish in sand-shale sequences. This is not precisely correct in all cases, but it is a good approximation. In all cases the effective porosity is distributed between the rock components in proportion to their solid rock volume, as recommended by Keys and Xu, 2002. The pores in the shale and the pores in the non-shale rock are treated differently. They are assumed to have different pore aspect ratios.

Effective porosity in shales can be a difficult concept to grasp. Figure 6 (slide 10) shows a dotted magenta line in the porosity track (second from the left, next to the lithology track) which is the unbounded effective porosity, labeled PHIEU. Where the porosity is colored, the rock is reservoir rock and has effective permeability. Where it is not colored, the rock is impermeable. In this example, the impermeable rock with effective porosity, contains small isolated sandstones and siltstones that are not interconnected. In conventional petrophysics these rocks are typically ignored because the free fluid they contain cannot be produced. When creating a petrophysical velocity model, the effective porosity, even if unconnected, must be taken into account. The effective porosity remaining in these shales, whether associated with siltstones or isolated sandstones, does affect the rock's strength and thus its acoustic properties.

Case Studies

Gulf of Mexico Example

Figure 6 (slide 10) is a petrophysical velocity model of a gas well in the Gulf of Mexico. The gas zone is shown in red and the underlying water in blue in the effective porosity track. The well has a measured compressional sonic log which is shown in black in the "Compressional" track. The red curve in the same track is the modeled compressional sonic, using in-situ fluids. The blue curve, in the same track shows what the sonic would read if the zone were wet. The well was drilled with synthetic oil-based mud, so the brine filled sonic is faster in the water column than the measured sonic and it is faster than the measured sonic in the gas column. They agree very well in the shale. A very small gas saturation in the water column causes a surprising difference in the in-situ sonic and the brine-filled sonic.

The density log differs from the brine-filled density quite a lot in the gas column due to the gas. Only small differences are seen between the measured density and the in-situ density due to shallow invasion and the effect of dissolved gas on the acoustic properties of the oil-based mud filtrate. The well does not have a measured shear log, so the modeled shear in red is compared to the famous "mudrock" equation of Castagna, et. al. (1985) in blue. The model agrees well with the mudrock equation in the shales, but the mudrock equation overestimates the shear interval transit time by a considerable margin in the gas column. This is to be expected because the mudrock equation is a function of the compressional sonic

alone.

The bulk modulus of the solid mixture is shown in the track to the left of the right hand depth track. The computed modulus is shown in black. The other curves are the Hashin-Shtrikman bounds (Hashin and Shtrikman, 1963) and the moduli of pure shale and pure sand. The pure shale and pure sand bounds are computed from the parameters supplied by the analyst. All bounding values are computed from equations taken from Mavko, et. al., 1998. These values, and corresponding bounding curves for the shear modulus and Poisson's ratio, provide some quality control on the results. If unrealistic velocity parameters are used or the input petrophysical model is unrealistic, the bounding values will probably be exceeded and the analyst will be warned that his model is in error.

China example
In figure 7 (slide 11), a section of a well in China, the borehole is very rugose. The caliper is displayed in the first track and is shaded to the bit size. Borehole rugosity is probably the leading cause of poor compressional and shear logs. In this case, both the measured compressional and shear are affected and are of poor quality. Both logs do somewhat better in the shales than in the sands, which is normal. In shales where the borehole is in good shape, invasion is not a problem due to low permeability and the logs can read the undisturbed rock.

The compressional sonic errors are typically less than 10 microseconds/ft, or less than 10%. The errors in the shear sonic are much larger, as much as 300 microseconds/ft and over 100% of the true value. This section of log shows that the worst shear errors are in the sandstones.

Opposite the oil zone one can see separation between the modeled in-situ sonic (in red) and the modeled brine filled sonic (in blue). They are both different from the measured sonic in black. The measured sonic is probably slightly off due to the washout at that depth. The difference in the brine-filled sonic and the in-situ sonic is due to hydrocarbon effect.

Second Gulf Of Mexico Example
Figure 8 (slide 12) shows a comparison of a Gulf of Mexico well (different from the previous example) and the 3D seismic through the well location. The well bore is shown plotted on the seismic section. In the central panel of the figure, the synthetic seismic section (acoustic impedance) from the well data is compared to the seismic itself. The comparison is only valid very close to the well bore path. The log data used for this synthetic is the measured compressional and density data from the well logs. Where the colors are pale the comparison is good, where they are intense the comparison is poor. The comparison is good above 3850 (shallowest third of the display) and poor below.

In figure 9 (slide 13) the same section of the well is shown compared to the 3D seismic, but this time the data used is the compressional sonic and density from the petrophysical velocity model. In this case the acoustic impedance computed from the modeled sonic and density compares very well over the whole wellbore. This is the most common use of the petrophysical velocity model, it is used to improve the well tie to seismic.

Second China Example
In this example (figure 10, slide 14) from China, the measured sonic log data was of exceptional quality. In our experience, in excess of 50% of field measured shear sonic logs have serious errors, but in this section of this well, the data is quite good. Even so, the offset reflectivity is better defined by using the modeled curves. The reflectivity (Y axis) versus offset angle (X axis) from the petrophysical velocity model is shown in the upper left and from the measured data it is shown in the lower left of the figure. The reflectivity from the model is more robust.

The seismic attributes computed from the petrophysical velocity model are shown in the upper right and from the measured data in the lower right. Sigma, Lambda, LambdaRho (LambdaRho is a trademark of PanCanadian Petroleum Ltd.) and Lambda/Mu (Goodway, Chen, Downton, 1997) are again better defined by using the modeled data, especially for gas (the red bar), but also for oil (green bar). This is because the model compensates for the effects of mud filtrate invasion. Filtrate invasion has a substantial effect on sonic and density logs.

The accuracy of the value Lambda, which is essentially the difference between the squared values of the compressional and shear sonic, is very sensitive to small errors in either measurement. Because the shear data are less accurate than the compressional data, particularly in sands, the shear measurement is a major cause of error in this calculation. The figures show that the form of the single interface AVO response (left graphs) is very similar in both log cases but significantly different in magnitude for the Lambda based attributes. This shows that correcting the shear measurement is important.

The wireline data shown in the figure is from field (wellsite) processing. The final computer center processing of this sonic data is in fairly good agreement with the velocity model data. The petrophysical velocity model was a significant improvement over the field processed data, even in this case where the waveforms collected in the field were of excellent quality (Gordon Marney, Pers. Comm..)

Conclusions

Using a petrophysical interpretation to build a petrophysical velocity model, if done using a wet shale model and effective porosity, is a valid and useful tool. Compressional sonic logs and density logs are subject to error due to borehole effects and drilling fluid invasion. Most shear logs, as measured by dipole sonic logs, have serious errors. These errors are probably also due to borehole effects and invasion, but are more common than errors in the other two logs. These effects can be corrected for with successful petrophysical velocity modeling.

The wet shale and effective porosity methodology is superior to the dry clay and total porosity methodology because the volume of shale and shale porosity parameters can be measured in the well bore under the appropriate conditions. The parameters used to compute the amount of clay-bound water (Phiclay*Vcl from the equation above) must be derived using laboratory data that were not measured in-situ. Clay minerals have acoustic properties that vary with temperature, salinity of the surrounding brine, and pressure. For these reasons, translating the laboratory properties to the rocks in question, in the well, is a very difficult task.

Very good sonic and density data are required for well ties to seismic data and for rock mechanical properties calculations. While sonic and density logs provide the ground truth data for model calibration, they are reliably accurate only in a good section of the borehole and in tight, uninvaded rocks. In invaded sandstones (especially hydrocarbon bearing sands) or rugose bore holes, they are often bad. In these sections of rock, the petrophysical velocity model results are the best data to use.

Acknowledgments

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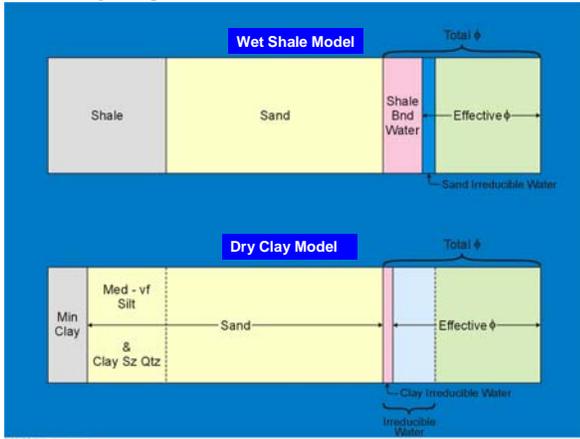
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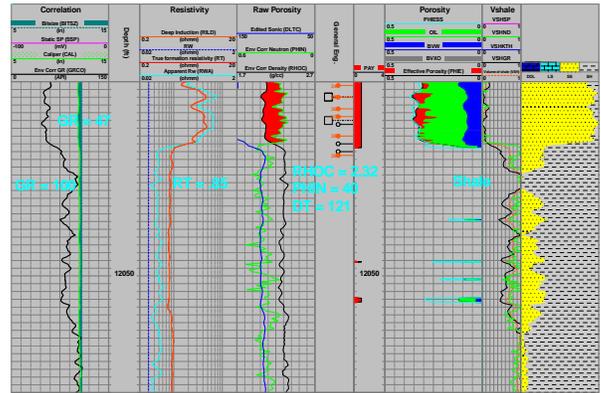## Petrophysical Rock Models

Figure 1

Volume of shale

Figure 2

Defining "Shale" on logs

Figure 3

Clays

Figure 4

Figure 5

Sonic when wet

Density
when wet

Wet
sonic

PHIEU

Figure 6

GOM Example

AI Model Insitu

After
Frederic
Gallice
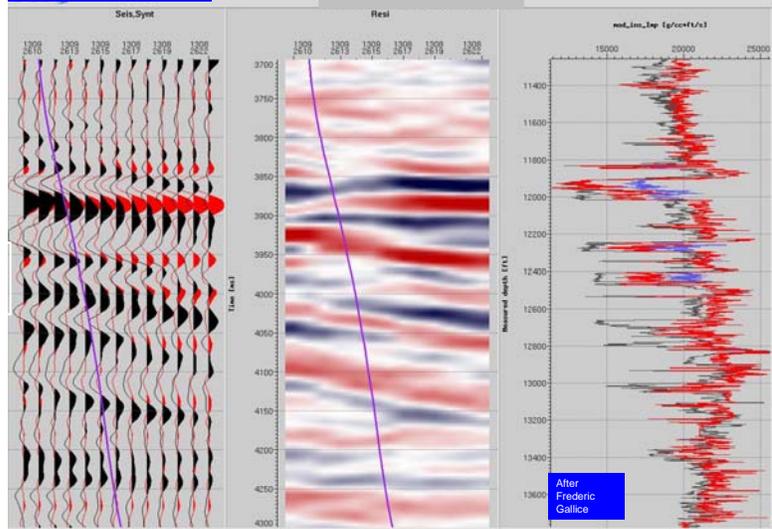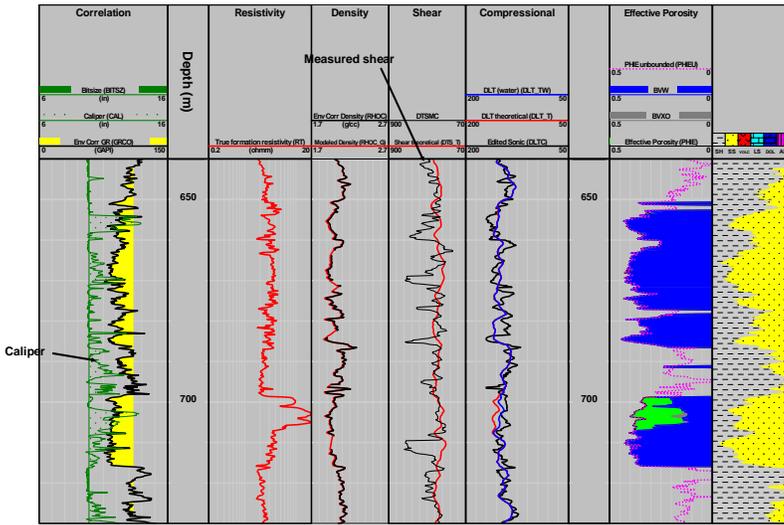
Figure 9

Figure 7

GOM Example

Measured AI

After
Frederic
Gallice

Figure 8

Figure 10