Scale in rock physics: Caveats and a remedy

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Inversion of the seismic amplitude into impedance is attractive because impedance is a layer property while amplitude is a property of the interface between layers. Impedance is directly measured during controlled experiments in the lab and in the well, together with porosity, mineralogy, pressure, and saturation. As a result, one can first establish rock physics transforms from the rock's elastic properties into its bulk properties and conditions and then apply them to the seismic impedance to describe the subsurface.

The scale of data acquisition is very important in this workflow. Remember that while a rock physics transform, such as that between velocity and porosity, is established at the lab or log scale of only inches and feet, we aspire to apply it to seismic data on the scale of tens and hundreds of feet. Direct and unconditional use of such rock physics transforms, applied to seismic impedance volumes without accounting for scale effects, will produce erroneous results.

Log-derived rock physics transforms

Consider log curves from an offshore well with several sand layers (Figure 1). The total porosity in the sand is greater than in the surrounding shale. As a result, we observe a substantial negative impedance difference between the shale and gas sand while the impedance difference between the wet sand and shale is essentially nonexistent.

Figure 2 displays the impedance-porosity cross-plots for these data, color-coded by gamma-ray. The sand data points appear blue while the shale is yellow-red. The gas-sand impedance-porosity trend is parallel and lies below the wet-sand trend (Figure 2, left frame). After theoretically substituting the in-situ pore fluid with the formation brine throughout the well we observe that the impedance in the (originally) gas sand becomes the same as in the wet sand (Figure 2, right frame).

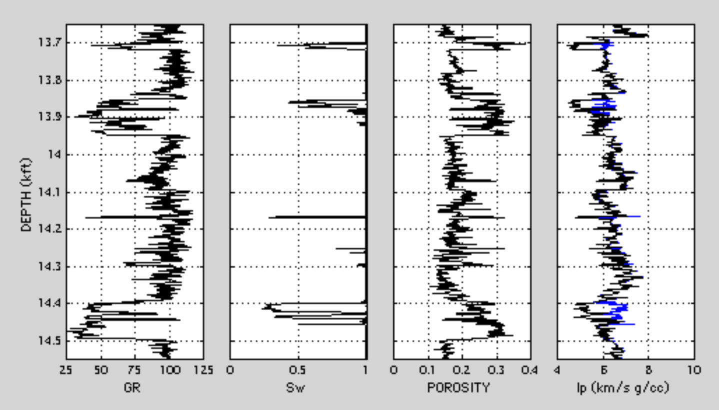

Figure 1. Well log curves for an offshore well. From left to right: gamma-ray; water saturation; total porosity; and P-wave impedance. In the impedance frame, the black curve is for the original data while the blue curve is the impedance calculated for wet conditions by fluid substitution.

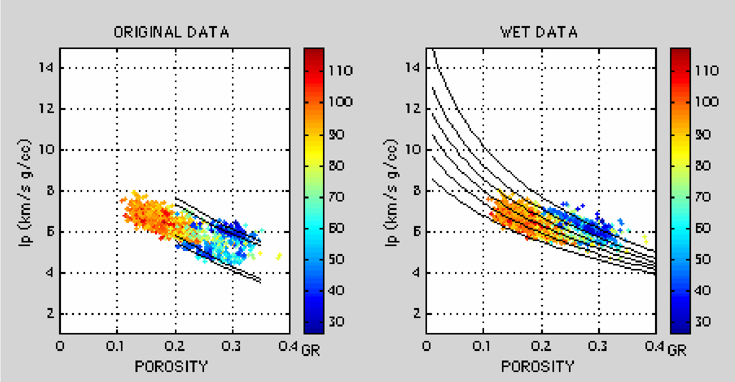

Figure 2. Impedance-porosity cross-plots for well data shown in Figure 1. Left: the original data. Right: the impedance calculated for wet conditions (blue curve in the impedance frame in Figure 1). The curves are from the uncemented (soft) sand/shale model.

The curves shown in the cross-plot come from the uncemented (soft) sand/shale rock physics model designed to relate the velocity to porosity and clay content in soft clastic sediment. In the left frame of Figure 2, the upper two curves are for wet sand with zero and 10% clay content while the lower two curves are for gas sand with the same clay content. In the right frame where the data points are for wet rock, each of the five model curves is produced for a fixed clay content ranging from zero for the upper curve to 100% for the lower curve with 20% clay increment, and for 100% brine saturation. The model curves accurately describe the trends observed in the data: the sand data lie between the zero-clay and 20%-clay curves while the shale data lie between the 20%-clay and 100%-clay curves.

This model constitutes a site-specific *log-scale* rock physics transform between the total porosity, mineralogy, and impedance. Can it be directly applied to the *seismic* impedance?

Seismic impedance in synthetic earth

To address this question, we construct a one-dimensional earth model with three gas sand layers of progressively increasing thickness (Figure 3). The porosity, clay content, and water saturation in the sand are constant, 0.4, 0.05, and 0.2, respectively. The shale background also has constant porosity 0.35 and clay content 0.8, and is fully water saturated. The *log-scale* impedance in the section is calculated from porosity, mineralogy, and fluid according to the soft sand/shale model.

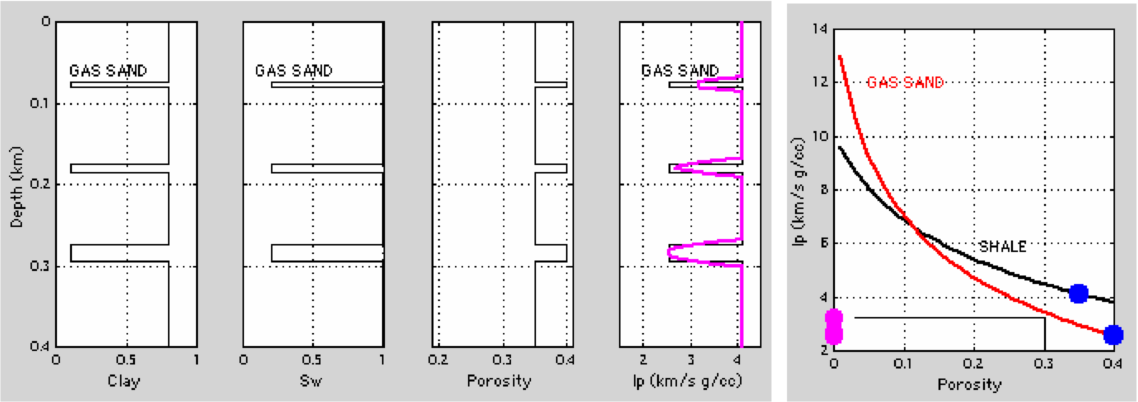

Figure 3. A synthetic earth model with three gas-sand layers. From left to right: clay content; water saturation; total porosity; and P-wave impedance. The magenta curve is the seismic-scale impedance. The frame on the right shows the impedance-porosity curves for gas sand and shale according to the soft sand/shale model. The blue symbols are for the log-scale impedance while the magenta symbols are for the seismic-scale impedance. The black horizontal line projects the seismic impedance in the thin gas sand layer onto the impedance-porosity curve. The vertical projection of the intersection yields erroneous porosity of about 0.3.

A simple way of calculating the *seismic-scale* impedance is via the Backus upscaling which uses a running harmonic average of the elastic modulus. This upscaled (seismic) impedance profile is shown in Figure 3 in magenta. The seismic impedance is the same as the log-scale impedance in the thick sand layer located at the bottom while it is noticeably different in the thin layer at the top. If this seismic impedance is used with the log-derived impedance-porosity transform, the predicted porosity in the sand will be about 0.3 instead of 0.4 (Figure 3, right-hand frame). This example illustrates the dichotomy due to scale in geophysical interpretation: a log-scale relation should not be blindly applied to seismic-scale data; porosity at a point cannot be always correctly mapped from seismic impedance. The reason is that an elastic property at a point cannot be accurately recovered from an experiment that employs large wavelengths. *Downscaling* is simply impossible without additional assumptions about the structure of the subsurface.

Instead of making such assumptions (which are often baseless away from well control), let us ask ourselves: Is there a scale-independent volumetric reservoir property and if there is, is there a scale-independent seismic attribute to map this property?

Cumulative reservoir property and cumulative attribute

One scale-independent reservoir property (let us call it Φ) is the total pore volume which is often referred to as ϕh where ϕ is the porosity and h is thickness. Generally, it is the integral of porosity with respect to depth z taken within the reservoir: $\Phi = \int \phi(z) dz$. We call Φ the accumulated porosity and plot it versus depth in Figure 4 for the synthetic earth model.

As a scale-independent seismic attribute that could be related to Φ we propose using the integral of the anomaly of the inverse impedance where the anomaly is defined as the difference between the values in the reservoir (I_p^{-1}) and background (I_{pB}^{-1}). This is a cumulative seismic attribute (CATT): $\mathrm{CATT} = \int (I_p^{-1}(z) - I_{pB}^{-1}(z)) dz$.

The CATT curves calculated for the log-scale impedance and seismic-scale impedance are shown in Figure 4. This attribute appears almost scale-independent. A cross-plot of the cumulative porosity and CATT shown in Figure 4 indicates that Φ can be uniquely determined form CATT no matter at which scale the latter attribute is measured. The reason for this scale independence is that the upscaling of the elastic moduli is done by means of the harmonic average. Therefore, the anomaly of the inverse modulus will be exactly scale-independent while the anomaly of the inverse impedance is approximately scale independent.

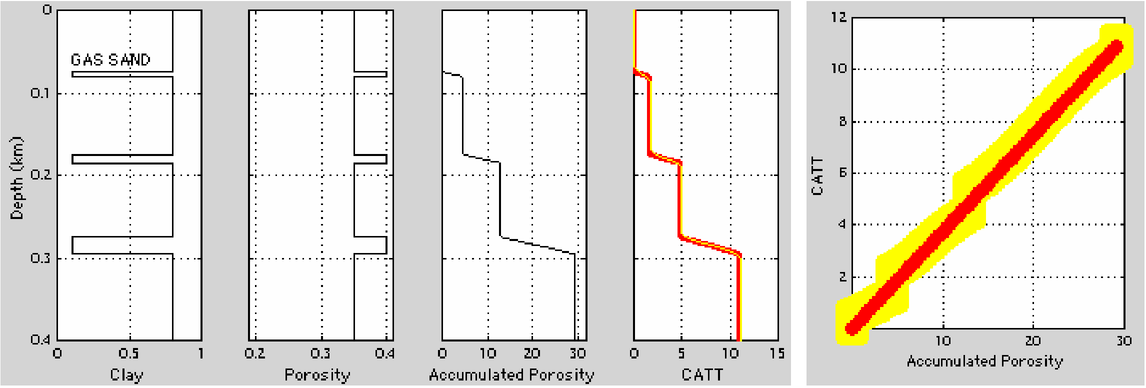

Figure 4. A synthetic earth model with three gas-sand layers. From left to right: clay content; water saturation; accumulated porosity; and CATT. The red curve is CATT calculated from the log-scale impedance while the yellow curve is CATT calculated from the seismic-scale impedance. The frame on the right shows the cross-plot of CATT versus the accumulated porosity. The color scheme is the same as in the CATT-depth frame.

CATTS from seismic

Consider next a normal-incidence synthetic trace obtained by the convolution of a Ricker wavelet with the reflectivity series in the earth model examined here (Figure 5). The uncalibrated seismic impedance can be calculated as the exponent of the integral of the trace. By calibrating it with the log-scale impedance at the gas sand in the bottom of the interval we obtain the calibrated seismic impedance trace. Finally, by integrating the anomaly of the inverse of this seismic impedance, we obtain the seismic CATT (Figure 5). This seismic-derived CATT is very close to the log-scale CATT. Moreover, a cross-plot of the former and the accumulated porosity in Figure 5 indicates that this scale-independent reservoir property can be recovered from a seismically-derived CATT.

These results indicate that porosity in thin sub-resolution layers cannot be correctly mapped by directly applying rock physics impedance-porosity transforms to seismic impedance volumes simply because the upscaled seismic impedance often differs from the actual fine-scale values. Instead, we propose mapping the product of porosity and thickness or, more precisely, the total pore volume of the reservoir. This cumulative measure of porosity can be related, by means of rock physics, to a new class of seismic attributes introduced here.

These are cumulative attributes (CATTS) which are calculated, for example, by an integration of a seismic impedance anomaly along the seismic trace. While the seismic impedance (acoustic and elastic alike) can be, simply speaking, estimated by integrating the trace, CATTS are estimated by integrating the trace repeatedly. This new class of seismic attributes potentially can be used in many geological environments for the purpose of mapping cumulative (or integrated) rock properties from seismic.

We envision that CATTS can be constructed in different ways for different situations, for the acoustic and elastic impedance alike, in order to map different cumulative reservoir properties. The concept of this new class of seismic attributes is a solution to the problem of downscaling inherent in mapping reservoir properties from seismic data. The principle offered here is to map *cumulative* reservoir properties through *cumulative* seismic attributes.

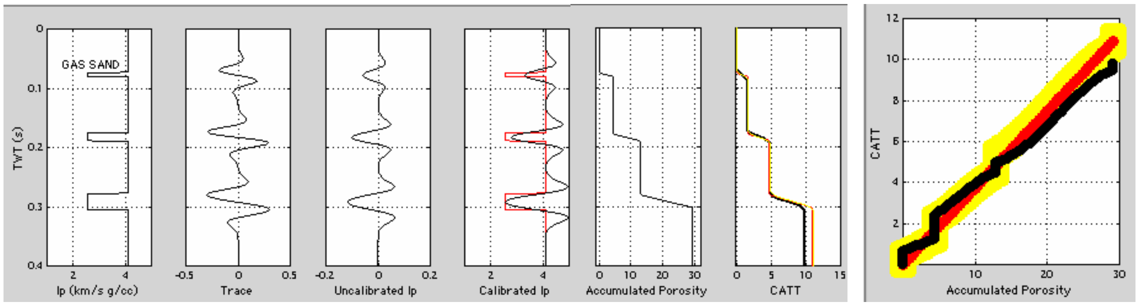

Figure 5. A synthetic earth model with three gas-sand layers. From left to right: impedance; normal-incidence trace; uncalibrated seismic impedance; calibrated seismic impedance (the log-scale impedance is shown in red); accumulated porosity; and CATT. In the CATT frame, the black curve is for the seismically-derived CATT while the red and yellow curves are the same as in Figure 4. The frame on the right shows the cross-plot of CATT versus the accumulated porosity. The color scheme is the same as in the CATT-depth frame.

Conclusion

Deriving reservoir properties from surface seismic data is a difficult task. Two major factors work against us. The first is non-uniqueness; a range of possible reservoir models will fit our seismic observations. The second challenge relates to overcoming scale effects. This paper suggests one solution to this problem. There is an increasing trend to use seismic data, along with traditional engineering data, to help quantify reservoir properties even to the point of using such data for economic predictions. For such methods to take hold, we will need to consistently and robustly address non-uniqueness and scale effects in our inversion workflows.