Seismic reflections depend on the contrast of the compressional and shear (P and S) wave velocity and density in the subsurface while the velocity and density, in turn, depend on lithology, porosity, pore fluid and pressure. These two links, one between rock’s structure and its elasticity and the other between the elasticity and signal propagation, form the physical basis of seismic interpretation for rock properties and conditions.

One approach to interpreting seismic data for the physical state of rock is forward modeling. Lithology, porosity and fluid in the rock, as well as the reservoir geometry are perturbed; the corresponding elastic properties are calculated; and then synthetic seismic traces are generated. The underlying supposition is that if the seismic response is similar, the properties and conditions in the subsurface that give rise to this response are similar as well. Systematically conducted perturbational forward modeling helps create a catalog of seismic signatures of lithology, porosity and fluid away from well control and, by so doing, sets realistic expectations for hydrocarbon detection and optimizes the selection of seismic attributes in an anticipated depositional setting.

The perturbation most commonly used in geophysics is fluid substitution in the reservoir where the pore fluid in a prototype well is theoretically replaced with different fluid (e.g., gas with brine), the new elastic properties are calculated, and synthetic seismic attributes are generated. Fluid substitution is based on Gassmann's theory and produces realistic results if the inputs are correct and the assumptions of the theory are satisfied.

Porosity and lithology substitutions are much less explored, yet these reservoir property perturbations could be instrumental in risk reduction and reserves estimates during exploration. The main difficulty in porosity and lithology substitutions is that a predictive and site-specific rock physics transform is needed to vary the rock's elastic properties as porosity and lithology are perturbed. Unfortunately for the modeler and interpreter, more than one of such transforms may exist in sediment. A technology that helps find these transforms is rock physics diagnostics.

Primer on rock physics diagnostics

This example is for a Gulf Coast well where a high-porosity gas sand reservoir is located at the bottom of an overpressured shale interval (Figure 1, top). To uncover the effects of porosity and clay on the velocity, let us first bring the data to the common fluid denominator by theoretically substituting the in-situ pore fluid with the formation brine throughout the well and calculating the corresponding elastic properties and density. This fluid substitution is needed to reduce by one the number of variables that affect the elastic-wave velocity and bulk density by balancing the pore-fluid effect in the well.

Next, we cross-plot the impedance versus the total porosity for the entire interval under examination (Figure 1, bottom). Brine-saturated rock exhibits two distinctively different trends, one for the sand and the other for the shale. The curves shown in the cross-plot come from the uncemented sand/shale rock physics model designed to relate the velocity to porosity and clay content in soft clastic sediment. Each of the five model curves (black) is produced for 100% brine saturation and for a fixed clay content ranging from zero for the upper curve to 100% for the lower curve with 20% clay increment. 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 60%-clay and 100%-clay curves. Notice that the commonly recommended relations by Wyllie and Raymer are not applicable in this depositional setting. Both strongly overestimate the impedance in the sand because these relations are only appropriate for cemented rock.

By establishing a site-specific rock physics transform (the uncemented sand/shale model)
Perturbational modeling at an interface

Because a relevant rock physics model is established, we can now confidently model the elastic properties in sand and shale for porosity and mineralogy ranges outside of the ranges present in the data. A simple way to perturb the rock is to set ranges for porosity and clay content variation in sand and shale, calculate the elastic-wave velocity and density within these ranges according to the model, and then map the result onto the impedance-Poisson’s ratio plane. Next, two points can be selected in this plane, one for the overburden and the other for the reservoir, and the amplitude variations with offset (AVO) response modeled at the interface between the two. In this example we assume that the total porosity in the reservoir may vary between 15% and 35% and the clay content between zero and 20%. The total porosity in the shale is between 10% and 40% and the clay content is between 60% and 100%. The sand is either 80% gas saturated or wet.

Let us ask ourselves, for instance, how the seismic response varies as the reservoir quality deteriorates; i.e., the total porosity in gas sand decreases from 35% to 15%. The forward modeling in Figure 2, top, indicates that the expected AVO response is of Class III for the high-porosity sand and merges towards Class I as the porosity and, therefore, total reserves are reduced. Using the same approach, let us investigate the effect of the fluid in, e.g., 30% porosity sand (Figure 2, middle). We find that while the response of the gas sand is of Class II, that of the wet sand is of Class I.
A less obvious yet very important question in exploration is how the seismic response varies if the properties of the gas reservoir remain the same but the overburden shale compacts and loses its porosity. This perturbation results in the intercept becoming increasingly negative and the AVO curve less steep (Figure 2, bottom).

**Transition from sand to shale**
The same forward modeling can be used to predict how the seismic response varies as the shale content in the sand increases. Several changes may happen simultaneously as sand transits towards shale. First, the mineralogy changes as the clay content increases. Second, the total porosity decreases as small clay particles fill the pore space between large sand grains. Finally, as the average grain size becomes smaller, the irreducible water saturation increases until it reaches 100% and good-quality gas sand becomes wet shaley sand.

This complex evolution in rock can be mapped into the impedance-Poisson's ratio plane (Figure 3) where four domains are shown: (a) gas sand with 20% water saturation, 30% to 35% porosity and zero-15% clay content; (b) shalier sand with 80% water saturation, 25% to 30% porosity and 20% to 30% clay content; (c) shaley wet sand with 15% to 25% porosity and 30% to 40% clay content; and (d) shale with 15% to 25% porosity and 60% to 100% clay content. The AVO response to this transition ranges from Class III for gas sand and shalier sand with residual gas to Class I for shaley wet sand (Figure 3).

**Onset of cementation in sand**
Contact cementation, quartz or calcite, can be encountered in high-porosity sand. Cement makes the frame of the sand strong and thus prevents compaction and further porosity reduction. Contact cementation is manifested by velocity and impedance being atypically high at high porosity, much higher than in the uncemented sand examined above. A different rock physics model has to be used to describe high-porosity sand with contact cement (Figure 4).

The results of perturbational modeling (Figure 5) indicate that the near-offset reflections in high-quality gas sand with contact cement may be very similar to those in high-porosity wet uncemented sand. Gas in cemented sand is mostly manifested by the amplitude becoming increasingly negative with offset. This example shows how careful rock physics analysis combined with forward modeling of seismic response can guide remote sensing of rock properties in exploration and avoid potential pitfalls.