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A rock-physics tutorial: Discovering a supermodel

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Summary

In this tutorial, I show the steps required to create models of reservoir rocks saturated with different fluids, with the aim of predicting elastic properties (velocity, impedance, moduli, etc.) for different geological scenarios. This modelling process is broken into four separate stages, three of which consider the different components of a reservoir rock, and the last of which brings these components together. Fluid substitution, rock-physics templates, upper and lower elastic bounds, and inclusion and contact models are all terms that get used in the modelling process. Here, I explain simply what these terms mean, how they fit together to produce a geologically relevant model, and point out where different Canadian geologies require specific considerations within the modelling process.

Introduction

The field of rock-physics modelling is incredibly diverse, and has the goal of trying to predict the properties of a rock with different compositions and fluid content. The specific properties being predicted: elastic moduli, attenuation, anisotropic parameters, depend on the application at hand, but the common aim of understanding the behaviour of rocks in different exploration and production cases is extremely useful.

Prediction of elastic properties can be used for generating synthetics, well-log prediction, or creating rock-physics templates for interpreting crossplots of inversion attributes. The process of modelling a reservoir rock can be broken into four steps: 1) Modelling the minerals, 2) modelling the fluids, 3) modelling the rock frame, and 4) assembling the components (Figure 1). This process follows the workflow common to different textbooks and research papers, and is presented here for geoscientists either new to the field, or seeking a better understanding of the modelling process.

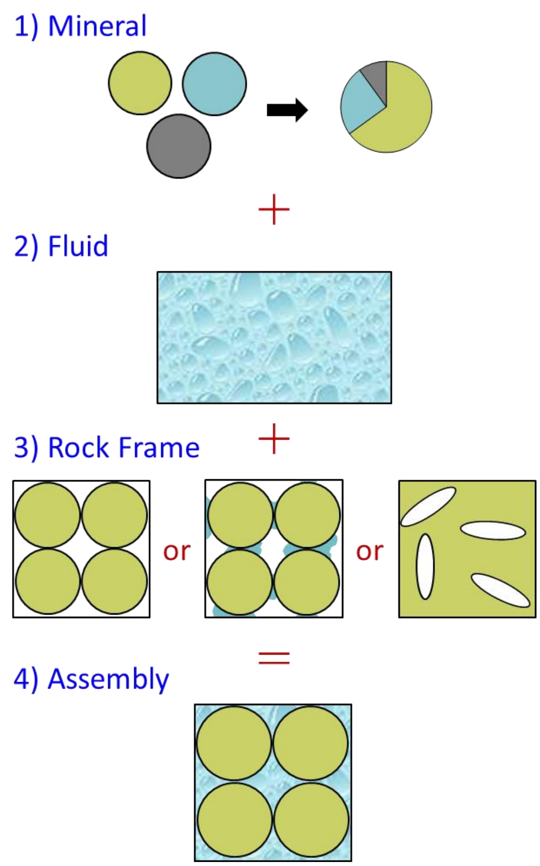

Figure 1. *Creating a rock-physics model can be broken into four steps: 1) Modelling the effective mineral properties, 2) Modelling the effective fluid properties, 3) Modelling the rock frame, and 4) Assembling the three components.*

Minerals

Mineral moduli and density are measured in the lab, and this data often isn't available on a field-by-field basis. Some minerals, such as quartz, have elastic properties that are very well understood, while other minerals, most notably clays, are substantially more difficult to quantify. Fortunately, a number of researchers have summarized published measurements. Mavko et al. (1998) for

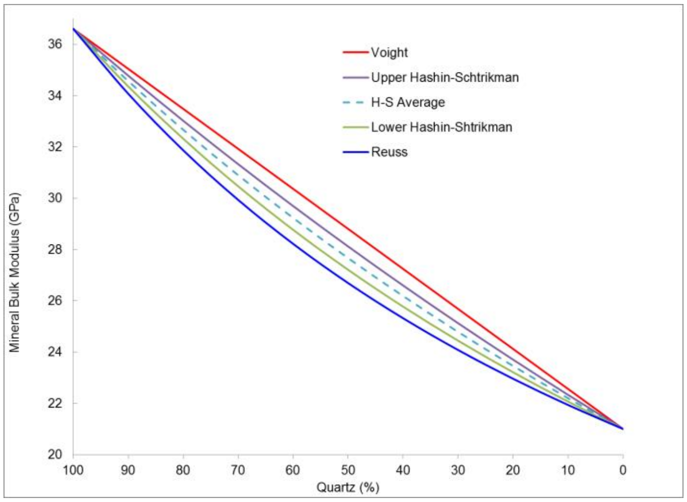

Figure 2. *Upper and lower bounds of the bulk modulus for a mixture of quartz and clay. Minerals typically have moduli values that are within an order of magnitude of one another, an average of an upper and lower bound (dashed line) is often appropriate.*

instance, tabulate dozens of different minerals from just as many sources, and Avseth et al. (2005) provide a similar table for the properties of clay minerals. For a single-mineral rock, searching these tables is all that is required for the mineral properties step.

For the more typical situation in which a variety of minerals are present, a set of effective mineral properties must be determined. Knowing the fractions of the minerals, from x-ray diffraction data or log analysis, is part of the picture to describe the mineral properties. Bounds and averages are also used to compensate for not knowing how the grains are arranged. Figure 2 shows a number of bounds for a mixture of quartz and clay. While for most situations an average of an upper and lower bound is sufficient, some situations make using an upper (stiff) or lower (soft) bound more appropriate (Avseth et al., 2005). Certain shale-gas plays are examples of where a soft bound could be used, where the rock is clay-dominated with suspended quartz grains.

Fluids

It has become conventional wisdom that gas causes a decrease in velocity compared to brine or oil, but it is also possible to quantify this effect. Fluid density and moduli are typically calculated using empirical relationships such as the well-known Batzle-Wang equations (Batzle & Wang, 1992), and subsequent expansions of that work (Han and Batzle, 2000a,b). These equations describe how the elastic properties of fluids are affected by reservoir temperature and pressure, and specific parameters for each phase. These parameters include the specific gravity of the gas, the API and gas-oil ratio of the oil, and the salinity of the brine.

The shear modulus of fluids is generally assumed to be zero, however heavy oil, such as that from Alberta's oil sands, violates this assumption. Batzle et al. (2006) discuss the shear properties of heavy oils, which have been measured as a function of temperature and frequency of investigation (Behura et al., 2007; Rodrigues & Batzle, 2013; Spencer, 2013). In general, the properties of heavy oils do not follow the Batzle-Wang relationships very well, and other models must be used (e.g. Han et al., 2014).

The elastic properties of the fluid are taken as an average of the three phases when the fluids are assumed to be uniformly saturated. If this is not the case, for example in some cases of water injection or gas dissolution, a patchy saturation model must be used. Figure 3 shows the effect on the fluid bulk modulus of increasing the hydrocarbon saturation.

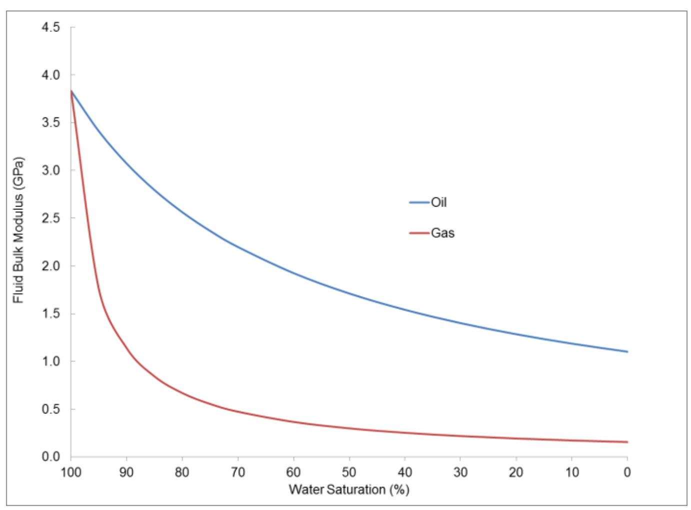

Figure 3. *Fluid bulk modulus for a mixture of water and oil (blue), and water and gas (red). Homogeneous saturation is assumed*

Rock Frame

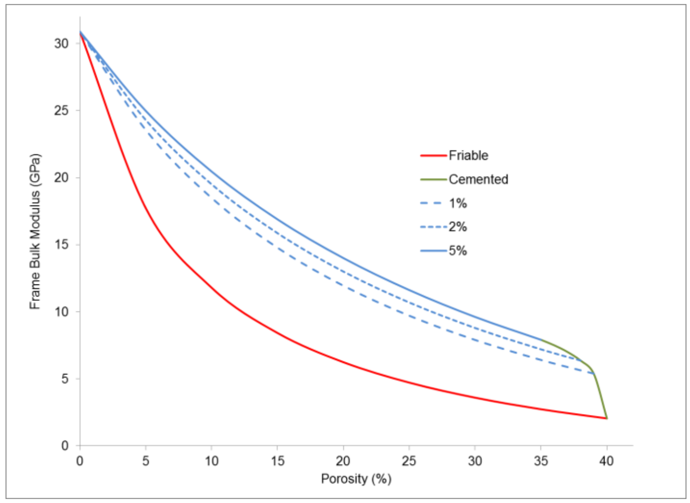

Figure 4. *Rock-frame bulk modulus for a rock consisting of 75% quartz and 25% clay. Introducing cement to the model (blue) increases the stiffness considerably over the unconsolidated case (red)*

Many different approaches exist to determine the stiffness of the rock frame itself. Known as the "dry" case, it is independent of fluid effects, and instead depends on how the rock is put together. Is it unconsolidated or cemented? Are the pores the result of grain packing, or are they due to cracks or dissolution? Other models and situations are also possible, but here I limit the discussion to these cases.

In unconsolidated rocks the elastic properties of the frame are determined for a packing of identical spherical grains (Dvorkin & Nur, 1996). The properties are therefore a function of how tightly packed the grains are, which in turn is a function of porosity, effective pressure, and the number of contacts per grain. Because of the assumptions on the grain uniformity, typically only the maximum porosity is modelled, with all other porosities, due to sorting or diagenesis, being an interpolation between the maximum-porosity and zero-porosity (mineral) endmembers. For sandstones, the maximum, or critical, porosity is often around 40%, but when clay minerals are present, this value can be lower (Nur et al., 1998).

Introducing even small amounts of cement can greatly increase the stiffness of a rock (Figure 4). Dvorkin and Nur (1996) present a model that describes this behaviour as a function of the cement's elastic properties and the amount of cement with respect to the grain distribution. As with the unconsolidated sand model, the critical porosity is modelled, with cement reducing the porosity by a few percent. Larger volumes of cement are accounted for using a different interpolation strategy between the critical-porosity and zero-porosity endmembers (Avseth et al., 2005).

Finally, inclusion models are sometimes used for low-porosity rocks (Xu and White, 1995) or rocks with fractures or dissolution porosity, such as carbonates (Xu and Payne, 2009). These models use the theory of Kuster and Toksöz (1974), which adds the effects of inclusions (pores) to a background medium with known properties. For shaly sands, such as the Montney, this starts with a mineral mixture of sand and shale, to which is added low-aspect-ratio pores for the inter-shale porosity, and high-aspect-ratio pores for the inter-sand porosity.

Assembly

Now that each of the components has been evaluated, and their elastic properties have been calculated, the remaining step is to put them together and describe the saturated rock as a whole. Density is simply a porosity-weighted average of the fluid and mineral densities, and the Gassmann equations (Gassmann, 1951) are used to calculate the saturated-rock moduli as a function of the three parts previously described. These equations account for the stiffening of the rock due to the increase in pore pressure from a seismic wave acting on the fluid, minerals, and frame together.

While the Gassmann equations are applicable in a wide variety of situations, there are circumstances in which alternatives must be considered. One of the assumptions of the equations is that the shear modulus of the rock remains unchanged due to the presence of the fluid. As mentioned previously, this is not the case for heavy oil, and generalized equations (Ciz and Shapiro, 2007), must be used. Low-porosity rocks, where there is little communication between pores, also violate the Gassmann model. In these situations, the Kuster-Toksöz theory is better employed, using inclusions that are fluid-filled rather than dry.

A further critical consideration is to calibrate the model to existing log and core data. Typically this is done by modelling a range of porosities, and observing the match to the data on a velocity versus porosity crossplot. This is an iterative process, in that the entire model must be assembled before the comparison can take place. Adjusting individual parameters and recalculating the model gives a great understanding to the relative contribution from each step.

Applications

After following these four steps, we are left with a bulk modulus, shear modulus, and density for a saturated rock with given parameters. Additional elastic parameters such as Young's modulus (E), Poisson's ratio (ν), $\lambda\rho$, $\mu\rho$, impedance (I_P, I_S), v_P:v_S, and others can now be derived as desired.

While creating a model with a single set of parameters may help give confidence in the understanding of a known rock type, the real power of rock-physics modelling is the ability to change parameters and investigate relevant scenarios. Defining elastic properties as a function of a geological change allows curves and grids to be defined. Figure 5 shows a rock-physics template modelled with changing porosity and clay content. The same grid is transformed between E vs. ν and $\mu\rho$ vs. $\lambda\rho$ spaces, and can now be used to understand the behaviour of seismic data that has been inverted to these same parameters.

Geological changes can be implemented at any stage of the process. Modelling changes in mineralogy is useful to distinguish between a low-clay and high-clay portion of reservoir, or determining if a carbonate is dolomitized. Changing fluid parameters can help identify the seismic response of oil versus that of water. A common scenario is to model a pressure drop below the bubble point, leading to gas coming out of solution. Even the progress of a steam front can be modelled by its heating effect on the hydrocarbons. Rock-frame modelling is primarily used to establish the effect of changing porosity on the rock, however investigating the effect of cement content is also possible.

Conclusions

Whether calculating inputs for a simple wedge model, predicting missing log data, or generating templates for crossplot interpretation, rock-physics models are a crucial tool. Although there is a great volume of papers and textbooks to sort through, the process can be understood in four stages: Modelling minerals, modelling fluids, modelling the frame, and assembling the components. Even making use of the basic principles allows for a great understanding of the main contributions to a rock's elastic behaviour.

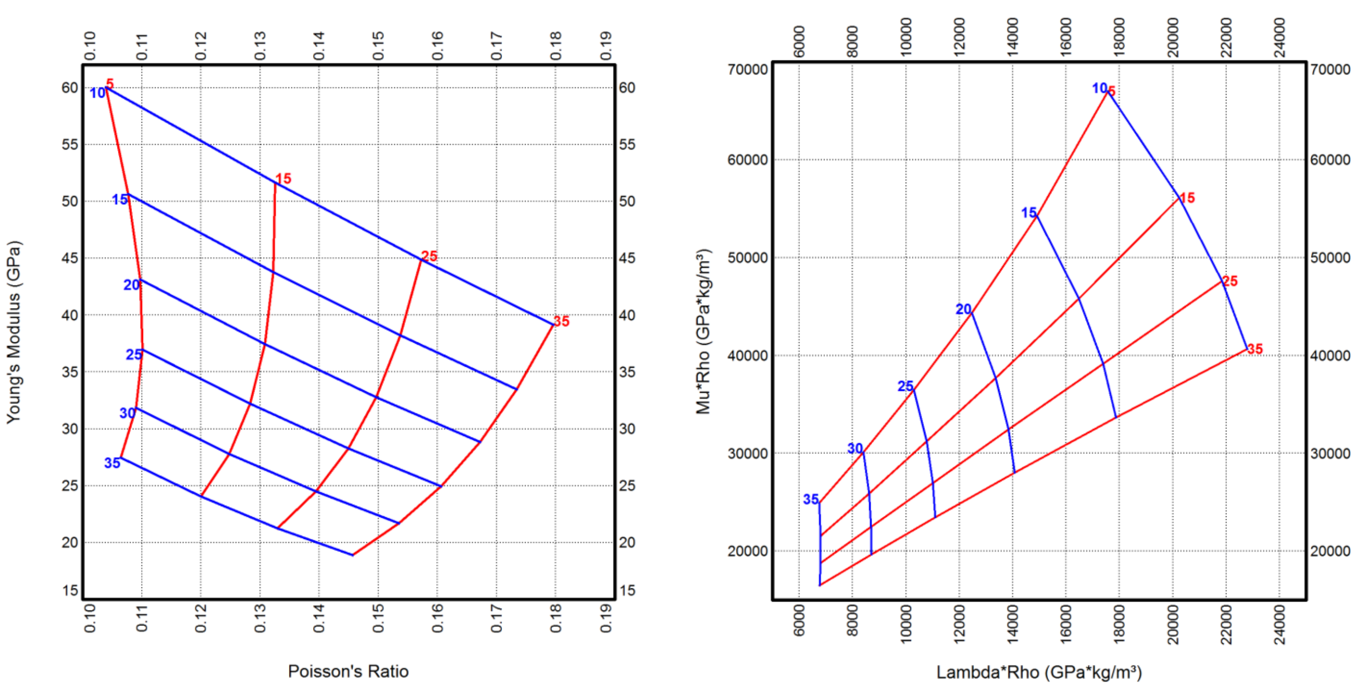

Figure 5. *Rock-physics templates transformed into E vs. ν and $\mu\rho$ vs. $\lambda\rho$ space. Red lines indicate constant lithology (clay content) and blue lines indicate constant porosity.*

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