Sounds Like Oil….?

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The million dollar question: One of the most common questions I get as a quantitative seismic interpreter, often from a geologist or an exploration manager, is whether it will be possible to detect oil or not from seismic data in a given area or location. If I know nothing else, my answer is "most likely not". But before I answer, I usually ask some questions back. "What is the age of the reservoir rock?", "How deep is the target buried?", "Has there been any tectonic influence or uplift?", "What is the temperature gradient in the area?", "What is the gravity of the oil?", "What do you know about the cap-rock?", "What is the quality of the seismic data in the area?". If these questions are answered with some degree of certainty, I will normally know quite soon whether there will be any hope of detecting oil from seismic data. How can I tell you? The short answer is "by using the rock physics link between geology and geophysics". The slightly longer answer is elaborated on below (see also Avseth et al., 2005):

It's all about rocks: Before you can say anything about what is inside the pore space of a rock, from seismic signatures, you need to have a very good understanding of the quality of the rock. You need to know your container (Figure 1). Imagine you have a coke bottle of firm glass in your hand and you are located in a dark room. Would you be able to tell whether it is filled with air or coke just by pressing the bottle with your hands? Probably not. What if you had a plastic bottle? Then you would more likely be able to tell the difference. The same concept applies to seismic waves. The propagation velocity of sound waves in rocks is directly linked to the compressibility of the rocks. If the rock is very stiff, it will be very difficult to use the seismic velocity information to discriminate whether the rock is filled with oil or water. However, if the rock is unconsolidated, in fact not a rock at all, but a sediment, then the seismic wave will behave quite differently when the sediment is filled with oil versus with water. The seismic P-wave velocity is normally significantly lower in an oil saturated sand compared to a brine saturated sand with the same porosity and pore stiffness (and even lower if it is filled with gas). So, a good rule of thumb is that if your reservoir is still unconsolidated, you should have a good chance of detecting oil in your reservoir from seismic amplitude data. But in addition, the oil should be relatively light. A heavy, viscous oil will normally have fluid incompressibility that is not very different from that of brine. A light oil (gravity > around 30 API), on the contrary, will be much easier for the P-wave to compress than brine. As rock physicists, we have a

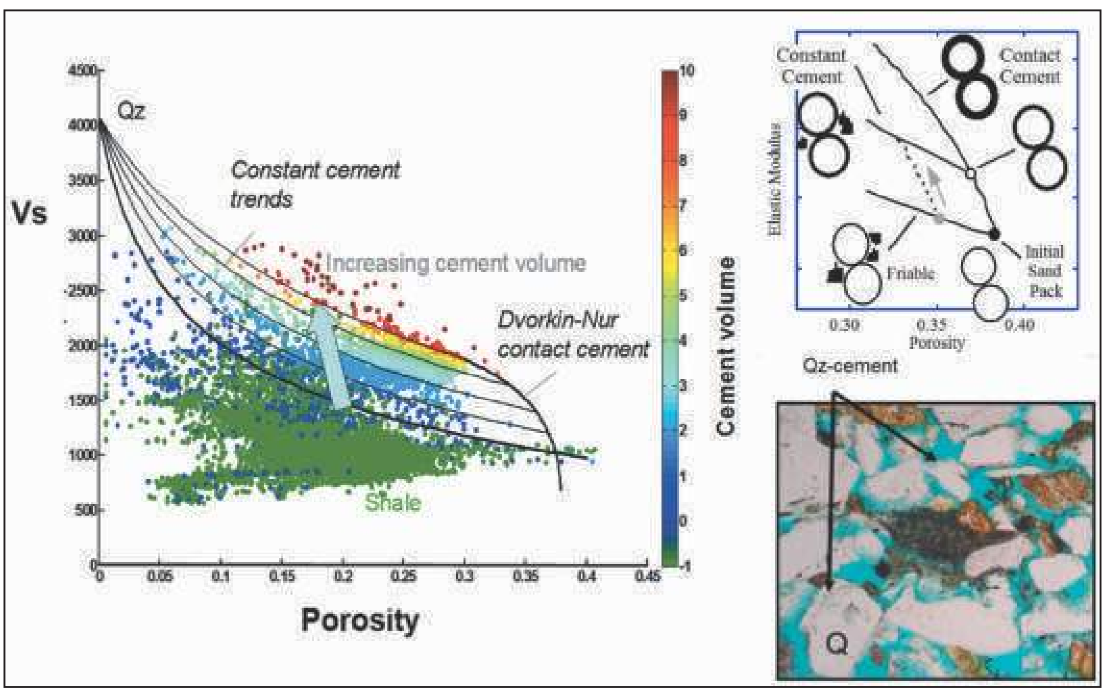

Fig. 1: The link between rock texture and elastic moduli (e.g., rock stiffness) is given via rock physics models. Hence, if we know the texture of a sandstone reservoir, we can predict the seismic velocities of this rock. Vice versa, we can predict rock texture from seismic velocities, given that we know the pore fluid. When we want to predict pore fluids from seismic velocities, we need to know the rock texture. Left plot shows well log data from the Alvheim field plotted on top of rock physics models (Shear wave velocity versus porosity). Colour code is estimated quartz cement volume. A thin-section from the same well confirms the presence of cement. The cement stiffen the grain contacts and reduce the fluid and stress sensitivity of the reservoir rock. (From Avseth et al., 2010).

very good understanding of the expected fluid sensitivity of a given rock, and we normally use the well-known Gassmann theory to estimate this (Mavko et al., 2009), what we often refer to as "fluid substitution analysis". However, when we use Gassmann, we need to know or assume the dry rock properties, that is the rock stiffness. If we have a cemented sandstone, the difference between oil and brine saturated rock will be very small even if the oil is light, and given that there are always some limitations with the seismic data (noise, resolution), it is normally impossible to detect oil in cemented sandstones.

Chemical brothers: So how do we know if the reservoir rock is cemented or not prior to drilling a well through this rock? Well, the geologists usually have a good understanding of the diagenetic processes of a rock. Hence, if we know the age of the rock, and the burial history of this rock, we can actually model and predict the amount of cement. This was done by Walderhaug and others more than 20 years ago at University of Oslo (Walderhaug, 1996). Recently, this knowledge has been incorporated into quantitative interpretation workflows (Dræge et al,, 2014; Avseth and Lehocki, 2016), exactly for the reasons outlined above. By coupling diagenetic models with rock physics models, we can actually predict the rock stiffness for a given rock prior to drilling (Figure 2). Then we can do our Gassmann fluid analysis with much greater precision and certainty. In a way, we can say that the geologic information helps us to constrain our geophysical inversion problem. There are always non-uniqueness and uncertainties in our predictions when we are looking at one or at most two seismic parameters (let's say acoustic impedance and Vp/Vs derived from offset-dependent seismic reflectivities = AVO inversion data) to try to say something about both reservoir quality and pore fluid content (Figure 3). But if we can constrain the reservoir quality from diagenetic models, we can much easier predict the fluid content from these seismic parameters. Also, if we have information about the shear wave velocity (Vs), we have a much greater chance in separating out the effect of fluids from that of lithology or rock stiffness, since the shearwaves (as opposed to the pressure or P-waves) are almost insensitive to pore fluids.

All models are wrong, but some are useful: Rock physics templates have been developed as a tool to better discriminate the rock quality effect from the pore fluid effect (Ødegaard and Avseth, 2004), see Figure 3, where the advantage of the shear wave information is included in the Vp/Vs ratio, a parameter that can be estimated from pre-stack seismic amplitudes together with the acoustic impedance. Recently, these templates have been used to constrain some seismic attributes that can be applied to both well log data and seismic inversion data. The fluid impedance (CPEI=curved pseudo elastic impedance) attribute will highlight the fluid effect, but suppress the rock stiffness effect in the data. On the other hand, the rock impedance (PEIL=pseudo elastic impedance for lithology) attribute will highlight variations in rock stiffness and suppress the fluid effect (Avseth and Veggeland, 2015). This is similar to the approach presented by Connolly (1996) and Whitcombe et al. (2001), but we use rock physics models instead of statistical correlations to find the optimal attributes. The attributes are presented in Figure 4, and examples of applications are shown in Figure 5 (well log data) and Figure 6 (seismic AVO inversion data), see also Avseth et al. (2016). By fine-tuning these attributes using well calibrations, we may be able to detect presence of both oil and gas in reservoirs that are even slightly cemented. However, as seen in Figure 4, the fluid sensitivity is drastically reduced with increased burial and associated increased arock stiffness.

The golden zone: It turns out that most oil reservoirs around the world are located around 2-3 km burial depth. This is because the source rocks need to be buried at a certain depth/temperature to become mature and generate oil, the reservoir rocks need to be still quite porous, and the cap-rocks need to be quite dense and impermeable. The combination of these various factors makes it favorable to look for oil in rocks present within this depth range. However, normally the

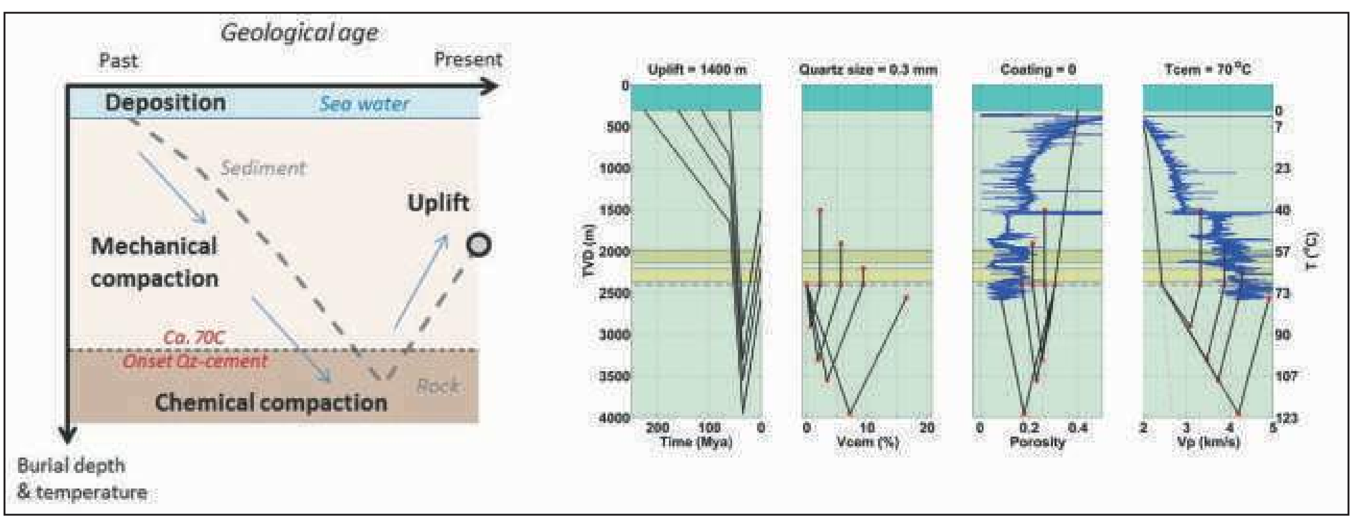

Fig. 2: The present day seismic properties will be a function of the burial history of the rock. By linking diagenetic modeling and rock physics modeling, we can predict the seismic velocities of rocks as a function of the geological processes through time. An example from a Barents Sea well, where a significant uplift has occurred, is shown to the right. The reservoir sandstones have been exposed to temperatures high enough to set off chemical compaction and the velocities are increasing drastically as a function of the cement (Avseth and Lehocki, 2016).

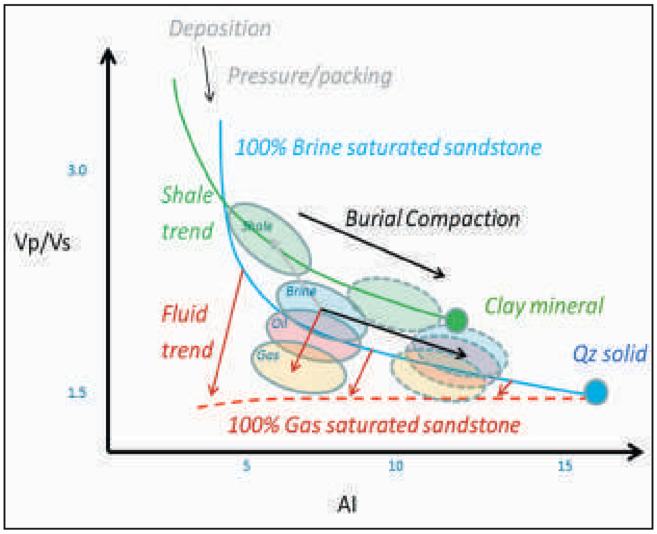

Fig. 3: A rock physics template showing expected seismic properties (acoustic impedance versus Vp/Vs) for different lithologies at different burial depths, with different types of pore fluids. There will be overlaps between brine saturated sandstones and oil saturated sandstones, and this overlap increases with increasing burial and rock consolidation. Hence, it will be increasingly difficult to predict hydrocarbons from seismic properties with increasing burial depth. (From Avseth and Veggeland, 2015).

temperature gradients are around 30-40 degrees per km, and quartz cementation tend to start at around 70-80 degrees (Bjørlykke, 2010). Hence, many of our oil reservoirs will be cemented! This is bad news in terms of seismic detectability of oil. What is often seen in seismic is the gas cap on top of oil, and the flat spot between the gas and the oil zone, especially in structural traps where the stratigraphy is oblique. But it is normally very difficult to see the transition from oil to water. However, with improved quality and resolution of seismic data (i.e. broadband data), and improved geological constraints, there is a hope that we should be able to detect presence of oil in cemented reservoirs located at around 2-3 km depth. Also, we see that many reservoirs can be oil filled even at much shallower depths due to significant uplift. The Jurassic reservoirs in the Barents Sea offshore Norway have been buried at depths of maybe 2.5km before being uplifted to a few hundred meters below the sea-floor, and are therefore slightly cemented. But because of light oil and good data, geophysicists have been able to detect the presence of oil in these reservoirs.Extra information from CSEM or gravity data have further enabled interpreters to avoid ambiguities between low fizz gas saturation and commercial oil saturation, with great success in the Barents Sea.

Always look on the bright side: We are presently experiencing tough times in our industry, with low oil price and quite

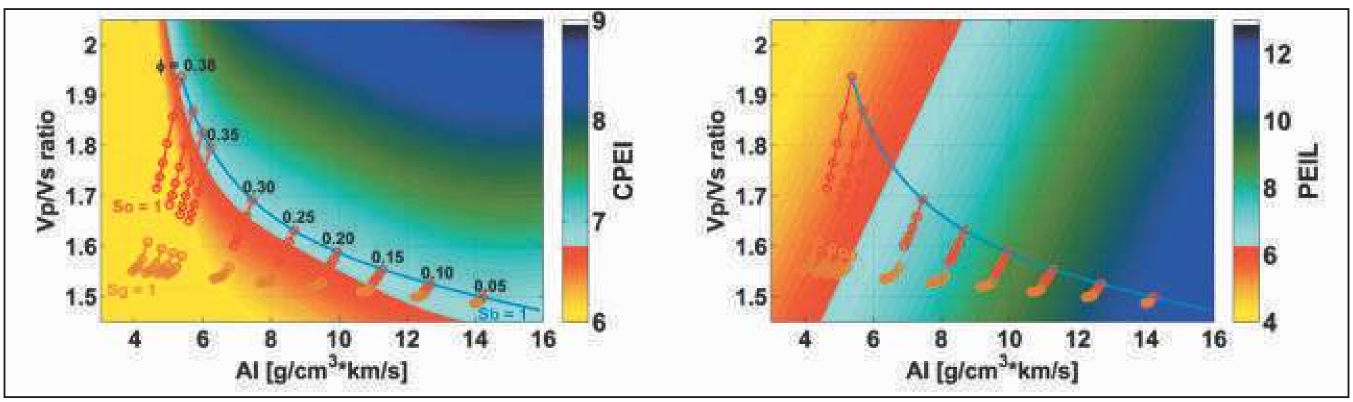

Fig. 4: Rock physics attributes defined from rock physics templates. Left: The fluid impedance (also named the "curved pseudo-elastic impedance, CPEI"). Right: The rock impedance (also called the "pseudo-elastic impedance for lithology, PEIL"). The fluid impdance will highlight hydrocarbons, whereas the rock impedance will be independent of fluids, but correlate with rock stiffness.

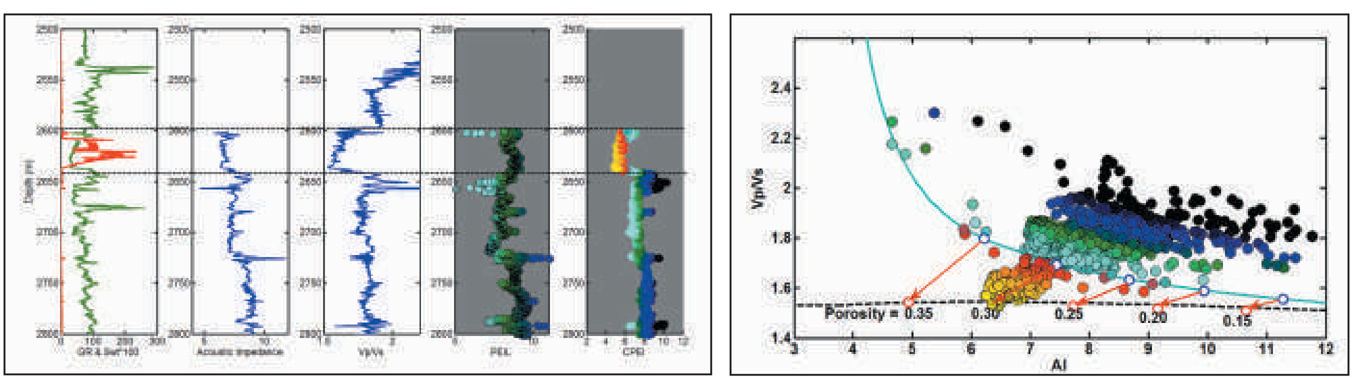

Fig. 4: Well log data from a Norwegian Sea well encountering a gas reservoir sandstone. The reservoir zone is easily detected using the fluid impedance (CPEI) rock physics attribute (warm colours in cross plot). Would we have seen this reservoir zone if it was filled with oil instead of gas? With light oil, probably yes, since the reservoir is quite porous and poorly consolidated.

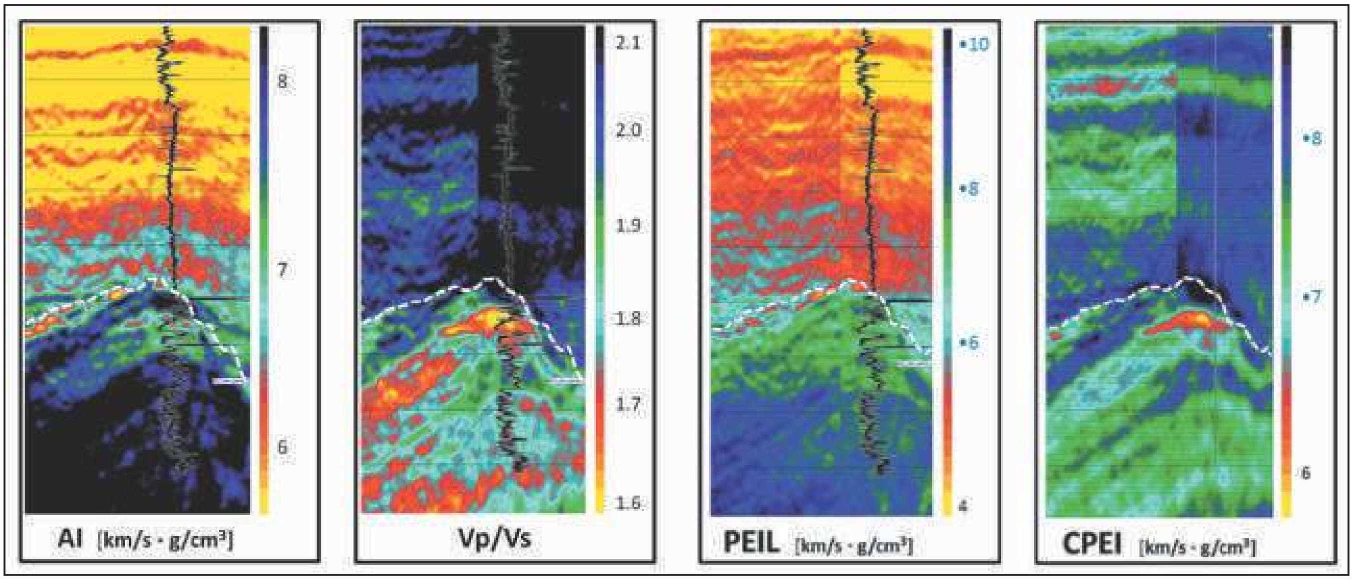

Fig. 6: Seismic AVO inversion results (acoustic impedance and Vp/Vs) juxtaposed with rock physics attributes including rock impedance (PEIL) and fluid impedance (CPEI). Note the anomaly in the fluid impedance, corresponding with a gas and condensate discovery in the Norwegian Sea (The Natalia discovery).

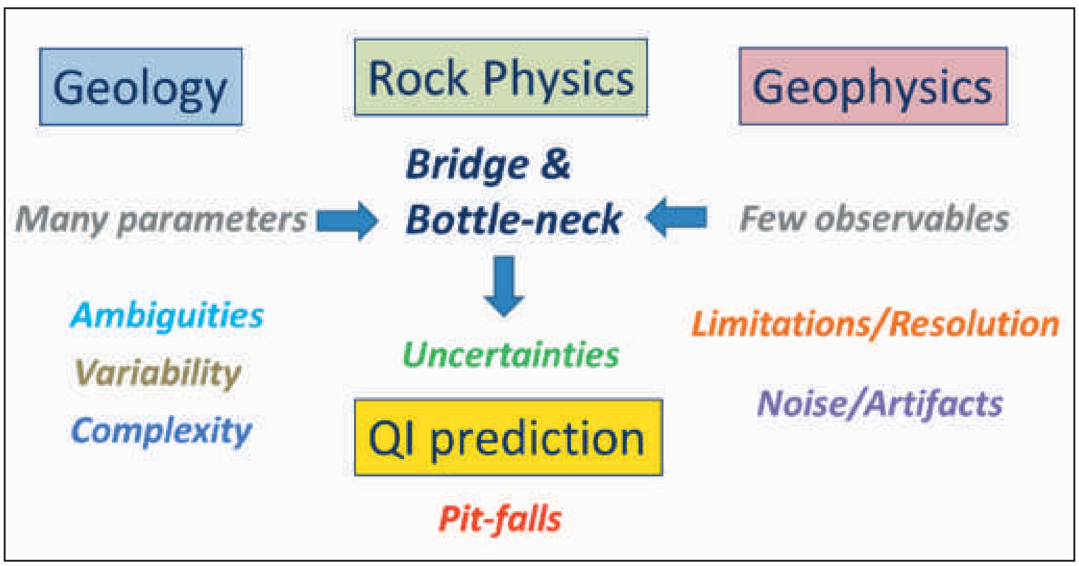

Fig. 7: Rock physics is the link between geology and geophysics. It is both a bridge and a bottle-neck during quantitative interpretation, as we often suffer from few geophysical observables, complex geology, model limitations and seismic resolution issues.

disappointing discovery ratesall over the world. On the Norwegian shelf, there is currently a shift in focus from conventional interpretation of structural traps to the search for more subtle stratigraphic traps. The use of broadband data and quantitative seismic interpretation is increasingly important. If we incorporate more geologic knowledge and integrate this with improved geophysical observations, there is a hope that we will be able to detect even more of the hidden oil that is present in relatively stiff sandstones. If we can push our seismic detectability of hydrocarbons only slightly, through improved data and better geologic constraints, we may be able to detect subtle differences between oil and water-filled sandstones tomorrow, that we are not able to detect today. Maybe we can make the dim spots bright up somehow?Promising work has been done (Goloshubin et al., 2014) on attenuation attributes and low-frequency seismic, where pore fluid effects may be manifested even if the amplitudes are dim, but we are still missing a rigorous physical understanding of what is really causing these frequency dependent effects. Moreover,with subtle differences between water-saturated and oil-saturated rocks, we are more prone to suffer from uncertainties and ambiguities (Figure 7). The only certain thing is that there is still plenty of hidden oil left to be discovered (Brown, 2013), and we will be working hard to find more of it from seismic data. Rock physicists and quantitative seismic interpreters will be busy investigating the sound of oil in years to come. So stay tuned for the next chapter in seismic oil exploration!

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