**Introduction**

Amplitude variation with offset (AVO) is a technique that has been used often to identify seismic anomalies as hydrocarbon reservoirs. Although it has worked well in the past, it has some limitations; the attenuation is often neglected, it assumes frequency independent reflection coefficients and it is limited by the resolution of the medium. The attenuation is not considered a significant issue in conventional AVO studies as there are methods available that compensate for its effects. In the case of a frequency dependent reflection coefficient, attenuation plays a major role in its effects and cannot be neglected.

A compressive wave, travelling through a saturated, porous medium develops a pressure gradient between the peaks and trough of the wave. This pressure gradient – first introduced by Biot (1956a,b) – which, in turn, causes attenuation of the wave and the reflection coefficient to become frequency dependent.

D’Este et al., local normal-incidence frequency band 

White’s stratified layered model (White et al., 1975) – arises due to the frequency dependance of the rock properties. This model has been shown to cause significant attenuation in the seismic frequency band (Pride et al., 2004).

**Method**

According to Carcione and Picotti (2006), the complex P-wave velocity, $V_c$, is acquired and used to calculate the phase velocity for each layer $p$.

$$V_c^P(V, \rho, \kappa, \phi)$$

and the quality factor: $Q = \frac{V_c^P(V, \rho, \kappa, \phi)}{V_c^P(V, \rho, \kappa, \phi)}$.

Using equations (1)-(4), the P-wave velocity ($V_c^P$), attenuation ($\gamma$), normal-incidence reflection coefficient ($R$) and phase angle ($\phi$) are plotted with respect to frequency and oil saturation/reservoir porosity. Both cases show similar velocity gradiets with porosity obviously having a larger difference. The porosity case shows an order of magnitude difference from the oil saturation case in all models except for the attenuation.

<table>
<thead>
<tr>
<th>Fluid</th>
<th>$K$ [GPa]</th>
<th>$\rho$ [g/cm$^3$]</th>
<th>$\phi$ [deg]</th>
<th>$Q$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water</td>
<td>24.69</td>
<td>1.00</td>
<td>0.504</td>
<td>30</td>
</tr>
<tr>
<td>Oil</td>
<td>32.56</td>
<td>0.85</td>
<td>0.700</td>
<td>40</td>
</tr>
</tbody>
</table>

**Application**

The results indicate that the method is not promising for deeper oil exploration; it could be beneficial to look at shallow oil reservoirs as the difference in bulk modulus might be magnified by less overburden.

**Acknowledgments**

We are grateful to Svenska Petroleum-Explotation and Det Norske Oil (DNNOil) for the data. A special thank you is extended to Thomas Liljedahl from Svenska Petroleum-Explotation and Erling Rykkvold from Aker BP for their valuable help and discussion on the topic and results.

**Conclusion**

The porosity affects the reflection coefficient, velocity and phase significantly more than oil saturation does. The attenuation however is more affected by saturation than porosity at 63%.

White’s model relies on the difference in bulk modulus of the saturating fluid (oil) and the surrounding rock matrix. A fluid saturated rock has a phase shift that is approximately equal to the phase shift in the surrounding rock matrix, and the attenuation caused by the phase shift is zero.

**References**


