Effects of fluid changes on seismic reflections: Predicting amplitudes at gas reservoir directly from amplitudes at wet reservoir

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ABSTRACT

The equations for fluid substitution in a sample with known porosity and the mineral’s and pore-fluid’s elastic moduli are well-documented. Discussions continue on how to conduct fluid substitution in practical situations where more than one fluid phase is present and the porosity and mineralogy are not precisely defined. We pose a different question: If we agree on a fluid substitution method, and also agree that at partial saturation the bulk modulus of the “effective” pore fluid is the harmonic average of those of the components, can we conduct fluid substitution directly on the seismic reflection amplitude? To address this question, we conducted forward modeling synthetic exercises: We systematically varied the porosity, clay content, and thickness of the reservoir and assumed that the properties of the bounding shale are fixed. Next, we used a velocity-porosity model to compute the elastic properties of the dry-rock frame and applied Gassmann’s equation to compute these properties in wet rock as well as at partial gas saturation. After that, we generated prestack synthetic seismic reflections at the top of the reservoir at full saturation and at partial saturation, and related one to the other. We found that within our assumption framework, there is an almost linear relation between the intercepts of the P-to-P reflectivity for the wet and gas reservoir. The same is true for the gradients. We have provided best-linear-fit equations that summarize these results. We applied this technique to field data and found that we can approximately predict the seismic amplitude at a gas reservoir from that measured at a wet reservoir, given that all other properties of the rock remain fixed. The solution given here should be treated as a method, meaning it should be tested and modified for various rock types and textures.

INTRODUCTION

Fluid substitution is one of the most important steps in seismic reservoir characterization and monitoring. It is commonly conducted on well data to quantify the resulting changes in the elastic-wave velocity and density. Then, synthetic seismic data are generated, analyzed, and compared to the field time-lapse data to determine fluid migration versus time (e.g., McCrank and Lawton, 2009; Sodagar and Lawton, 2010). The same approach can be used to assess the in situ fluid type away from well control. The question asked in this case is what seismic response to expect when the fluid and rock type vary. The principle here is similar to that employed in time-lapse analysis: The well data are used to establish a rock physics model (e.g., velocity-porosity-mineralogy transform) relevant to the geologic scenario under examination. Then, the rock properties and fluid are perturbed to find a synthetic seismic response at this new “synthetic” reservoir. The resulting seismic amplitude is compared to real seismic data to determine the rock and fluid behind the seismic reflection (Spikes et al., 2008).

The question we pose here is whether there are simple recipes that can, at least approximately, guide us in predicting a reflection at the shale-gas-sand interface if the reflection at the shale-wet-sand interface is known (and vice versa). In other words, is it possible to conduct fluid substitution directly on seismic data; and if it is, how? Clearly, if such relations exist and they are stable, even within a limited range of rock types and properties, they will be practically valuable as a reconnaissance and seismic interpretation tool.

A precursor work addressing essentially the same idea is by Zhou et al. (2006). These authors used trends developed from well log data to perform fluid substitution on seismic amplitude and presented a convincing field example to demonstrate the usefulness
of the technique. Their assumption was that the reservoirs from down-dip to up-dip are identical except for the pore fluid. Important work by the same group of authors (Ren et al., 2006; Hilterman and Zhou, 2009; Zhou and Hilterman, 2010) addresses the sensitivity of various seismic attributes to water saturation as well as rock type.

Our approach to addressing this question is to use a rock-physics-driven synthetic seismic forward modeling on a three-layer earth model where a reservoir is sandwiched between two identical shale half-spaces. In the forward-modeling exercise that follows, we cover large ranges of lithology and porosity in shale and sand. By using these synthetic results, we directly compare the amplitudes at a reservoir as the fluid varies. We find that the intercept and gradient of a reflection at the wet reservoir are approximately linearly related to these reflection parameters at the gas reservoir, and provide equations for these linear transforms. Finally, we use the same approach in a field example where a full-stack seismic section at the wet sand reservoir is transformed into a section at a gas reservoir. This transform is developed using well data that allowed us to find appropriate velocity-porosity and clay-porosity models.

PRIMER: SEISMIC REFLECTION BETWEEN TWO HALF-SPACES

We compute reflections at an interface between two elastic half-spaces, where the upper one is occupied by wet shale and the lower is occupied by sand that can be wet or partially gas-saturated. We fix the properties of the water and gas by assuming that their bulk moduli are 2.54 and 0.053 GPa, respectively, and the densities are 0.98 and 0.166 g/cc, respectively.

We also fix water saturation at 40% and compute the bulk modulus of the water/gas mixture as the harmonic average of those of the components, whereas the density of the mixture is the arithmetic average of those of the components. The resulting bulk modulus and density are 0.087 GPa and 0.492 g/cc, respectively.

We randomly select the clay content of the overburden shale between 0.60 and 1.00 and its porosity between 0.10 and 0.30. These parameters in the sand vary between zero and 0.20 and 0.10 and 0.40, respectively. For each pair of the shale and sand properties, we compute the P-wave impedance in the sand and shale from either the soft-sand or stiff-sand model. The former theoretical rock physics model is designed to relate the elastic properties to porosity and mineralogy in unconsolidated or weakly consolidated rock, where the porosity reduces not due to diagenetic cementation, but rather by deteriorating grain sorting. In contrast, the stiff-sand model provides a velocity-porosity trajectory relevant to porosity reduction due to diagenetic cementation. Both models are discussed in Mavko et al. (2009).

The normal reflectivity is computed, then, as the difference between the impedance in the sand, minus impedance in the shale, divided by the average of these impedances. This gives us four combinations: soft shale and soft sand; soft shale and stiff sand; stiff shale and soft sand; and stiff shale and stiff sand. Finally, we plot the normal reflectivity from gas sand versus that from wet sand. We repeat these random realizations hundreds of times to fill in the crossplots with all possible occurrences.

The normal P-to-P reflection at the shale-gas-sand interface is plotted versus that at the shale-wet-sand interface in Figure 1 for

![Figure 1](image)

Figure 1. Normal reflection at the top of gas sand versus that at the top of wet sand computed, as described in the text. The modeling scenarios are listed in the plots.
the four combinations of the velocity-porosity models. In spite of the large ranges of the rock properties used in this forward modeling, we obtain tight fluid substitution crossplots.

For example, for the soft-shale-soft-sand combination, if the wet sand is seismically invisible in normal reflections, i.e., the intercept is zero, we expect the intercept at the top of gas sand to vary between about \(-0.25\) and \(-0.15\) (Figure 2, left). If the intercept at the wet sand is \(-0.25\), that at the gas sand is expected to vary between \(-0.45\) and \(-0.35\). Contrarily, if the intercept at the top of the gas sand is \(-0.2\), that at the top of the wet sand is expected to vary between \(-0.1\) and zero. If the former is \(-0.4\), the latter is about \(-0.2\) (Figure 2, right). The same exercise can, of course, be conducted for a reflection at an angle.

One crucial parameter not examined in this primer is the thickness of the reservoir. The following computational experiments take this effect into account.

**EFFECT OF THICKNESS**

The earth model used here includes a layer of sandstone sandwiched between two infinitely wide and identical shale bodies (Figure 3).

Depending on the depth and the degree of consolidation of rock, at least two rock physics models can be employed to describe how the elastic properties are related to porosity and mineralogy. These are (1) the stiff-sand model representing consolidated rock and (2) the soft-sand model representing unconsolidated and uncemented formations (Mavko et al., 2009). We explore both models by assuming that (1) shale and sand are consolidated (stiff) and (2) shale and sand are unconsolidated (soft).

![Figure 2](image1.png)

Figure 2. Same as the top-left crossplot in Figure 1, but with white lines indicating the ranges of prediction variation, as explained in the text.

We start with the stiff-sand model, and for the purpose of forward modeling, fix the properties of the shale surrounding the sand reservoir by assuming that the shale is wet and its porosity and clay content are 0.15 and 0.70, respectively. The bulk modulus of the formation water is assumed 2.54 GPa, and its density is 0.98 g/cc.

The sandstone layer can have variable thickness, porosity, and clay content. The thickness is varied as a fraction of the wavelength \(\lambda\), and spans the interval between \(\lambda/2\) and \(\lambda/16\). The porosity of the stiff sand varies between 0.10 and 0.30, and its clay content varies between zero and 0.20. This sand can be wet or partially saturated with gas at (assumed) fixed water saturation 40%. The bulk modulus of the gas is assumed 0.053 GPa and its density is 0.166 g/cc. The effective pore-fluid properties at partial water saturation are computed as the harmonic average for the bulk modulus and the arithmetic average for the density.

In the next set of forward modeling computations, we use the soft-sand model for shale and sand. The porosity and mineralogy of the shale remain the same as in the stiff-sand case; however, the porosity of the sand is now varied between 0.15 and 0.35, with its clay content varying in the same interval as used in the stiff-sand case. Also, because unconsolidated rock typically occurs at depths shallower than consolidated rock, we reduce the bulk modulus of the gas to 0.026 GPa, and its density to 0.119 g/cc.

In our forward modeling of the elastic properties of the sand, we randomly and independently vary its porosity and clay content within the above-mentioned ranges. Next, we simulate the synthetic P-to-P seismic reflection at the top of the reservoir by using the Zoeppritz (1919) equations, and convolve the reflectivity series thus produced with the Ricker wavelet of fixed frequency. The angle of incidence in these examples varies from zero to 30°. The AVO attributes, the intercept \((R_0)\) and gradient \((G)\) are calculated from the synthetic prestack seismic data using Shuey’s (1985) approximation of the Zoeppritz (1919) equations

\[
R_{pp}(\theta) = R_{pp}(0) + \left[ ER_{pp}(0) + \frac{\Delta \nu}{(1 - \bar{\nu})^2} \right] \sin^2 \theta + \frac{1}{2} \frac{\Delta V_P}{V_P} (\tan^2 \theta - \sin^2 \theta),
\]

where \(R_{pp}(\theta)\) is the P-to-P reflection amplitude at the angle of incidence \(\theta\); \(\nu\) is Poisson’s ratio; and \(V_P\) is the P-wave velocity. Also,

\[
E = F - 2(1 - F) \left( \frac{1 - 2\bar{\nu}}{1 - \bar{\nu}} \right), \quad \frac{\Delta V_P}{V_P} = \frac{\Delta \rho}{\bar{\rho}}, \quad \frac{\Delta V_P}{V_P} = \frac{\Delta \rho}{\bar{\rho}}
\]

![Figure 3](image2.png)

Figure 3. The earth model used in our computational experiments.
where $\rho$ is the bulk density. In addition,

$$
\Delta \nu = \nu_2 - \nu_1, \quad \bar{\nu} = (\nu_2 + \nu_1)/2;
$$

$$
\Delta V_p = V_{p2} - V_{p1}, \quad \bar{V}_p = (V_{p2} + V_{p1})/2;
$$

$$
\Delta \rho = \rho_2 - \rho_1, \quad \bar{\rho} = (\rho_2 + \rho_1)/2; \quad (3)
$$

where the subscript “1” is for the properties of the upper half-space while “2” is for the lower half-space.

Following Hilterman (1985, unpublished notes), we only use the first two terms in equation 1 because the third term is small at $\theta < 30^\circ$. Then, the amplitude produced by the Zoeppritz (1919) equations was fitted by equation

$$
R_{pp}(\theta) = R_{pp}(0) + \left[ ER_{pp}(0) + \frac{\Delta \nu}{(1-E)^2} \right] \sin^2 \theta, \quad (4)
$$

where the first term was used for the intercept $R_0$, while the coefficient in front of $\sin^2 \theta$ in the second term was used for the gradient $G$. In most cases, the gradient is negative because the reflection amplitude decreases with the increasing angle of incidence.

Our objective is to compute these AVO attributes for the two cases: (a) wet reservoir and (b) reservoir with gas. Then, we will relate the intercept and gradient at full water saturation to those at partial water saturation and produce best-fit relations between the intercept at wet reservoir and that at gas reservoir, as well as between the gradient at wet reservoir and that at gas reservoir versus varying reservoir thickness, porosity, and the clay content.

Because we use the Zoeppritz (1919) equations in our computations, the effect of tuning is automatically taken into account. As expected, in a certain thickness range, we expect amplitude enhancement as compared to that at an interface between two half-spaces. This is why we observe this effect in our crossplots in Figure 4 as well as in the following crossplot figures.

**Results for fixed-clay content and varying porosity**

Figure 4 displays the results for the “stiff” sand and shale for the reservoir’s thickness $\frac{\lambda}{2}$, $\frac{\lambda}{4}$, $\frac{\lambda}{8}$, and $\frac{\lambda}{16}$. Figure 5 displays the same modeling results, but for the intercept. We observe practically linear relations between these attributes computed for wet and gas sand because the sand’s porosity varies for each of the selected sand thickness. The same is true for the intercept (Figure 5).

Moreover, if we superimpose all four graphs from Figure 4 on top of each other and do the same with the graphs from Figure 5, we still observe that fairly tight linear relations hold for all

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Figure 4. The gradient at the top of the gas reservoir versus that at the wet reservoir for a fixed clay content 0.10 and varying porosity (0.10 to 0.30) for stiff sand and shale. From left to right and top to bottom: reservoir thickness $\frac{\lambda}{2}$, $\frac{\lambda}{4}$, $\frac{\lambda}{8}$, and $\frac{\lambda}{16}$ wavelength. The symbols are color-coded by the porosity of the reservoir. Dashed line is a diagonal.
thicknesses (Figure 6). These relations can be approximated by the following best-fit equations:

\[ G_{\text{Gas}} = 1.0015G_{\text{Wet}} - 0.0480, \quad R^2 = 0.9973; \]
\[ R_{0_{\text{Gas}}} = 1.1938R_{0_{\text{Wet}}} - 0.0590, \quad R^2 = 0.9876. \]  

(5)

The same synthetic exercise was conducted for the earth model shown in Figure 3, but for the unconsolidated shale and sand whose elastic properties are now related to porosity and mineralogy by the soft-sand model. The shale’s porosity and mineralogy remain the same as in the previous exercise, but the porosity of the sand varies now between 0.15 and 0.35, with the clay content fixed at 0.10. The summary plots of the gas-sand versus wet-sand gradient and intercept for varying thickness are shown in Figure 7. The best-linear-fit equations now are

\[ G_{\text{Gas}} = 1.2890G_{\text{Wet}} - 0.1190, \quad R^2 = 0.9783; \]
\[ R_{0_{\text{Gas}}} = 1.4039R_{0_{\text{Wet}}} - 0.1639, \quad R^2 = 0.9489. \]  

(6)

Clearly, in this case, the spread of the computed values around the best-fit lines is more prominent than in the stiff-sand case. However, we deem it acceptable, bearing in mind the commonly sizeable error bars in real seismic data.

Results for fixed porosity and varying clay content

To explore how the clay content in the reservoir affects the transforms between the wet and gas case, we fix the porosity of the “stiff-sand” reservoir at 0.25 and vary its clay content from zero to 0.20. The summary crossplots for varying thickness are shown in Figure 8.

The best-linear-fit equations now are

\[ G_{\text{Gas}} = 1.0914G_{\text{Wet}} - 0.3970, \quad R^2 = 0.9932; \]
\[ R_{0_{\text{Gas}}} = 1.0775R_{0_{\text{Wet}}} - 0.0602, \quad R^2 = 0.8338. \]  

(7)

The results of exactly the same exercise but for the “soft” sand and shale are shown in Figure 9. The linear fit in this case is not as accurate as for the case shown in Figure 8. However, we still deem it satisfactory. The best-linear-fit equations are now

\[ G_{\text{Gas}} = 1.0032G_{\text{Wet}} - 0.1141, \quad R^2 = 0.7875; \]
\[ R_{0_{\text{Gas}}} = 1.7408R_{0_{\text{Wet}}} - 0.1310, \quad R^2 = 0.7122. \]  

(8)

The results of these two types of computational experiments (separately varying porosity and mineralogy of the sand) indicate that for a fixed reservoir thickness, a reasonably tight linear trend can be derived to relate the gradient and intercept at the top of the gas reservoir to those for wet reservoir. Moreover, even if we vary the thickness, these combined linear trends still constitute the results

Figure 5. Same as Figure 4, but for the intercept.
that can be approximated with a single linear trend for each of the rock physics model selected.

**Results for varying porosity and varying clay content**

Next, we simultaneously vary the porosity and clay content in the consolidated (stiff) sandstone reservoir sandwiched between two stiff shale half-spaces (Figure 3). The properties of the shale remained the same as used in the previous discussion. The porosity and clay content ranges for the stiff sand also remained the same. We conduct the synthetic seismic modeling for the elastic properties of the sand reservoir corresponding to all combinations of its porosity and clay content and for the wet and gas reservoir cases. Also, we conduct modeling for all four cases of the reservoir thickness, \( \lambda_2 \), \( \lambda_4 \), \( \lambda_8 \), and \( \lambda_{16} \). The results we report here are for the difference between the gradient at the wet and gas reservoir \( (\Delta G = G_{\text{Wet}} - G_{\text{Gas}}) \) and for the intercept difference \( (\Delta R_0 = R_{0\text{Wet}} - R_{0\text{Gas}}) \). Table 1 lists the mean, minimum, and maximum of \( \Delta G \) for a fixed reservoir thickness and all combinations of its porosity and clay content. In the same table, we also list the mean, minimum, and maximum of \( \Delta R_0 \). In addition, in the bottom row of this table we list the mean, minimum, and maximum of these differences for all four thicknesses.

We conduct the same exercise, but for the soft-sand case, with exactly the same parameters as used for the soft-sand case in the above sections. The results are listed in Table 2. The results listed in Tables 1 and 2 are plotted in Figure 10 as the mean, minimum, and maximum of the gradient and intercept difference versus the inverse thickness which is, as before, expressed as a fraction of the wavelength.

As indicated by Figure 10, the uncertainty spread (error bar) is often unacceptably large. This means that if we do not know the exact values of porosity and clay content in the reservoir, our fluid substitution transform between the reflections at the wet and gas reservoir is not practically acceptable.

To mitigate this situation, let us to recall that in many sands the porosity and clay content are related to each other as put forward by the famous Thomas-Stieber model for the porosity in formations with layered shale beds, or where structural shale is present (detailed in Mavko et al., 2009). Once such a relation is established, we do not have to independently vary the clay content and porosity; we only have to vary the clay content and assign the porosity values for the pure-sand and pure-shale end members. The following field study illustrates this approach.

**APPLICATION TO FIELD DATA**

We apply the seismic-scale fluid substitution methodology developed on synthetic examples to field data. The full-stack seismic section with a strong negative amplitude at a potential reservoir is shown in Figure 11. No prestack data or angle stacks are available. A well was drilled on the assumption that this sandstone reservoir contained gas somewhere between 3700 and 3800 m. However, in

![Figure 6](image-url)  
Figure 6. Four graphs from Figure 4, placed on top of each other (left), and the same for the four graphs from Figure 5 (right). The straight lines are from the first (left) and second (right) equation 5. The stiff-sand case. Dashed line is a diagonal.

![Figure 7](image-url)  
Figure 7. Same as Figure 6, but for unconsolidated soft shale and sand as explained in the text.
the well, the sand layer appeared to have 100% water saturation. The question we pose now is how the full-stack seismic response would look if gas was present.

The well data in the interval surrounding the potential reservoir are shown in Figure 12. The negative amplitude visible in Figure 11 at about 3.15 s TWT has apparently been produced by the low-impedance, low-GR, and coarsening upward sand layer with a higher-impedance layer above, further enhanced by the high-impedance spike between 3720 and 3730 m, which could be a carbonate streak or highly compressed shale. The thickness of this layer is greater than $\frac{1}{4}$ wavelength.

The total porosity $\phi$ was computed from the bulk density $\rho_b$ by assuming that the density of the mineral phase was 2.65 g/cc and the density of the fluid was 1.00 g/cc

$$\phi = \frac{2.65 - \rho_b}{1.65}. \quad (9)$$

The clay content $C$ was computed by linearly rescaling the GR curve with the minimum GR value in the section ascribed to pure sand and the maximum GR value ascribed to pure clay.

The velocity-porosity crossplots for the well interval displayed in Figure 12 are shown in Figure 13. Here, we observe a clear separation in the velocity-porosity behavior between sand and shale:

![Figure 8](image-url)

Figure 8. Same as Figure 6, but for fixed porosity and varying clay content. The symbols are color-coded by the clay content of the reservoir.

![Figure 9](image-url)

Figure 9. Same as Figure 8, but for unconsolidated soft shale and sand, as explained in the text.

<table>
<thead>
<tr>
<th>Thickness</th>
<th>Min $\Delta G$</th>
<th>Mean $\Delta G$</th>
<th>Max $\Delta G$</th>
<th>Min $\Delta R0$</th>
<th>Mean $\Delta R0$</th>
<th>Max $\Delta R0$</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\frac{1}{4}$</td>
<td>0.0317</td>
<td>0.0428</td>
<td>0.0498</td>
<td>0.0156</td>
<td>0.0434</td>
<td>0.0853</td>
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<td>$\frac{1}{2}$</td>
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<td>0.0591</td>
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<td>0.0559</td>
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<tr>
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<td>0.0682</td>
<td>0.0101</td>
<td>0.0503</td>
<td>0.1221</td>
</tr>
<tr>
<td>$\frac{1}{2}$</td>
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<td>0.0321</td>
<td>0.0416</td>
<td>0.0050</td>
<td>0.0295</td>
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<tr>
<td>All</td>
<td>0.0185</td>
<td>0.0472</td>
<td>0.0682</td>
<td>0.0050</td>
<td>0.0448</td>
<td>0.1221</td>
</tr>
</tbody>
</table>

Table 1. The gradient and intercept differences (minimum, mean, and maximum) between the wet and gas stiff reservoirs as explained in the text.
(a) the sand has a higher porosity, reaching almost 0.15, whereas the porosity of the shale does not exceed 0.05; and (b) within the overlapping porosity range, the velocity in the sand is higher than in the shale. The latter point becomes even more pronounced when we superimpose model lines on top of the data (also in Figure 13).

The model we use here is the constant-cement model (Mavko et al., 2009) that describes the velocity-porosity-mineralogy behavior in partially cemented clastic rock. The mathematical expression of this model is the same as in the soft-sand model (the modified lower Hashin-Shtrikman bound, also described in Mavko et al., 2009), but with an artificially high coordination number (the average number of grain-to-grain contacts) to express the effect of cement between the grains. Specifically, in this case we used the coordination number 15; differential pressure 40 MPa; critical porosity 0.40; the bulk modulus of the fluid (water) 2.60 GPa, and its density 1.00 g/cc. The mineralogy is a mixture of quartz and clay, with the commonly used bulk and shear moduli and mineral density: 36.60 GPa, 45.00 GPa, and 2.65 g/cc for quartz; and 21.00 GPa, 7.00 GPa, and 2.58 g/cc for clay. As we can see in the first two graphs in Figure 13, the model accurately mimics the data; therefore, it can be used in our fluid substitution workflow.

The third graph in Figure 13 is the crossplot of the total porosity versus clay content for the well interval shown in Figure 12. We see that as the clay content increases and the rock transitions from pure sand to pure clay, the porosity decreases. For simplicity, we approximate the observed behavior by a linear trend

\[ \phi = (1 - C)\phi_{SS} + C\phi_{SH}; \quad C = (\phi_{SS} - \phi)/(\phi_{SS} - \phi_{SH}). \]

Table 2. Same as Table 1 but for the soft reservoir and shale.

<table>
<thead>
<tr>
<th>Thickness</th>
<th>Min ΔG</th>
<th>Mean ΔG</th>
<th>Max ΔG</th>
<th>Min ΔR0</th>
<th>Mean ΔR0</th>
<th>Max ΔR0</th>
</tr>
</thead>
<tbody>
<tr>
<td>1/2</td>
<td>0.0838</td>
<td>0.1184</td>
<td>0.1516</td>
<td>0.1057</td>
<td>0.1581</td>
<td>0.2076</td>
</tr>
<tr>
<td>1/4</td>
<td>0.1001</td>
<td>0.1310</td>
<td>0.1919</td>
<td>0.1502</td>
<td>0.1689</td>
<td>0.1821</td>
</tr>
<tr>
<td>1/8</td>
<td>0.1132</td>
<td>0.1721</td>
<td>0.2238</td>
<td>0.1118</td>
<td>0.2230</td>
<td>0.3093</td>
</tr>
<tr>
<td>All</td>
<td>0.0675</td>
<td>0.1123</td>
<td>0.1405</td>
<td>0.0617</td>
<td>0.1585</td>
<td>0.2750</td>
</tr>
</tbody>
</table>

Figure 10. The results from Tables 1 and 2, plotted versus the inverse thickness of the reservoir. The units of the thickness are fractions of the wavelength; meaning that, e.g., the value of the inverse thickness eight corresponds to the thickness being 1/8 of the wavelength. The vertical gray lines show the spread around the mean values.
where \( \phi_{SS} \) is the porosity of the sand end-member while \( \phi_{SH} \) is that of the clay (shale) end-member. By selecting \( \phi_{SS} = 0.15 \) and \( \phi_{SH} = 0.03 \), we arrive at the clay-porosity relation

\[
C = -8.33\phi + 1.25, \quad \phi = 0.12(1.25 - C). \tag{11}
\]

This equation is plotted as a straight line connecting the pure-sand and pure-shale end points in Figure 13, right.

We need to emphasize that this relation is local, and may change in a different depositional setting or due to varying diagenesis. Moreover, the \( C \) versus \( \phi \) behavior does not have to be linear (see discussion in Mavko et al., 2009). Still, we feel that involving a more sophisticated sand/clay mixing model is not warranted by the extent and quality of the data we are dealing with and a simple linear relation in equation 11 is sufficient for our purposes.

To obtain a seismic-scale wet-to-gas sand transform, we once again use the sandwich earth model shown in Figure 3. The elastic properties of the wet shale surrounding the sand were computed using the constant-cement model (as described in the text) for porosity 0.04 and clay content 0.80. For the sand body, we varied the porosity between 0.05 and 0.20, and estimated the corresponding clay content from equation 11. The reflectance amplitude was synthetically computed in the same fashion as described earlier in the text for (a) wet sand whose thickness varied between \( \frac{1}{16} \) and \( \frac{1}{2} \), and (b) gas sand with gas saturation 60% and the gas bulk modulus 0.05 GPa and its density 0.17 g/cc. The effective properties of the pore fluid were computed as the harmonic average of the bulk moduli of the components and the arithmetic average of their densities.

The resulting crossplots of the gradient, intercept, and full-stack amplitude (up to 30° angle of incidence) at the top of the reservoir are shown in Figure 14 for varying porosity in the sand and its varying thickness. The relations thus produced are close to linear and can be approximated as

\[
G_{\text{Gas}} = 1.0954G_{\text{Wet}} - 0.0559, \quad R^2 = 0.9932; \\
R0_{\text{Gas}} = 1.2447R0_{\text{Wet}} - 0.0617, \quad R^2 = 0.8942; \\
RS_{\text{Gas}} = 1.0945RS_{\text{Wet}} - 0.0674, \quad R^2 = 0.7000; \tag{12}
\]

where \( RS \) is the full amplitude stack between zero and 30° and all other symbols are the same as used earlier in the text.

Now we can apply the wet-to-gas transform expressed by the third expression in equation 12 to the full-stack field seismic amplitude at the top of the reservoir and, by so doing, translate it into the amplitude at a hypothetical gas reservoir (Figure 11). This transform applied directly to a seismic section can guide us in derisking a prospect in depositional settings similar to that examined here. The ratio of the predicted amplitude to the original amplitude is plotted in Figure 15.

**CONCLUSION**

The question posed in this work was whether it is possible to (at least approximately) transform the seismic amplitude registered at a reservoir that is wet, to the amplitude at a hypothetical reservoir that is exactly the same as the wet reservoir, but contains gas. In other words, is it possible to conduct fluid substitution directly on seismic data?

We address this question by means of seismic forward modeling conducted on a simple three-layer earth model where a sand is sandwiched between two identical shale bodies. From a number of computational experiments, we find that there are approximately linear relations between the gradient and intercept at a wet reservoir and those at a gas reservoir. These relations appear to be reasonably stable as the porosity and thickness of the reservoir vary.

However, if we simultaneously vary the porosity and clay content in the reservoir, the error bars of such relations become large. This is why we include an additional constraint, that the porosity is inversely related to the clay content. Once such transform is in place, the uncertainty of the amplitude transform between the wet and gas reservoir diminishes.

This approach is used in our field example, where we directly transform the full stack amplitude at a wet reservoir to that at a gas reservoir under the assumption that the porosity and clay

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Figure 11. Top: Full-stack seismic section under examination (wet reservoir) with the well’s position shown by a vertical line. Middle: The peak negative amplitude extracted from this section (wet reservoir). Bottom: The peak negative amplitude obtained from that shown in the middle, using the third expression in equation 12. This is the full-stack amplitude expected at a gas reservoir.
content in the gas reservoir are exactly the same as in the wet reservoir and, moreover, the properties of the shale above and below the reservoir remain the same. This field example does not include explicit validation because we do not have seismic data at a gas reservoir comparable to the wet reservoir under examination. Hence, this case study has to be treated as an example of a change in real seismic data due to replacement of water with gas and using our rock-physics-based technique.

![Figure 12. Well data. From left to right: gamma-ray; bulk density; P- and S-wave velocity; P-wave impedance; and Poisson’s ratio.](image)

![Figure 13. First two graphs: Velocity versus porosity from the interval shown in Figure 12 color-coded by the clay content. The curves are from the rock physics constant-cement model described in the text. The upper curve is for pure-quartz wet rock and the lower curve is for pure-clay wet rock. The curves in-between are for gradually increasing clay content (top to bottom) with a 20% increment. The third graph is a crossplot of porosity versus clay content, color-coded by the clay content. The line is an interpolation between the pure sand and pure clay points as explained in the text.](image)
We feel it is important to once again list the assumptions used here:

- the wet and gas reservoirs are exactly the same except for the pore fluid present;
- the elastic properties of the shale surrounding the reservoir are known and fixed;
- the properties of the water and hydrocarbon (gas), as well as the hydrocarbon saturation, are known;
- the real earth can be approximated by a simple three-layer model;
- the wavelet is known; and
- the velocity-porosity and porosity-clay rock physics models are established.

In spite of the limitations forced upon the final result by these assumptions, we feel that they are not much more severe than those used in many traditional seismic modeling studies, meaning that the results presented here are practical and useful. Moreover, we encourage the reader to treat this discussion as a method rather than directly taking the equations presented here and applying them to a different field case. Depending on the rock type and real earth geometry, this workflow needs to be implemented on a case-by-case basis with a rigorous rock physics analysis as the basis. Such rock physics models can be established (as shown here) from well data, or assumed based on geologic circumstances at hand.

Our overall conclusion is that it is possible to quantify seismic amplitudes for reconnaissance and derisking purposes by applying the fluid substitution techniques described here directly to the seismic traces.

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