Rock physics reservoir characterization is based on applying rock physics relations, such as between velocity and porosity, to a volume of seismic velocity or impedance resulting from seismic inversion. The relevant rock physics laws are often derived from well log data. The spatial scale of log measurements is much smaller than the seismic scale. It is important to upscale rock physics relations used or to make sure that they hold at the seismic scale.

Well 1803 in La Cira field (Colombia) is within a good-quality seismic coverage. We have used the seismic data to obtain velocity inversion in a strip that contains this and other wells (Figure 1), using Hampson-Russell software package with the well 1803 sonic log for initial velocity model.

First consider well 1803 from where good quality velocity and shalines log data are available (Figure 2). It is clear from the graph that low velocity corresponds to low shale content and high velocity corresponds to high shale content. Let’s relate one to the other in order to obtain a relation usable for reservoir characterization. The resulting crossplot is given in Figure 3. Apparent is the absence of a meaningful trend. One possible reason for the absence of a trend is the apparent difference in the frequency of data presentation in Figure 2: the shale content data has smaller spatial frequency than the velocity data.

Figure 1. Geometry of the strip in La Cira Field where seismic inversion has been conducted.

Figure 2. Shale content and compressional-wave velocity versus depth in well 1803, La Cira.

Figure 3. Shale content versus velocity as cross plotted from well log curves given in Figure 2.
La Cira Case Study:  Upscaling

By applying a running mean average to log data, we smooth them as shown in Figure 4. Now we can cross plot these smoothed data by plotting only selected (every 10th) data point. A clear trend appears in the data that can be used to predict shale content from seismic velocity inversion (Figure 5).

The main question to be addressed here is whether this shale content versus velocity trend can be used for interpreting seismic inversion velocity in terms of shale content for a volume of seismic data.

Figure 4.  Running mean average applied to well log curves given in Figure 1.

Figure 5.  Cross plotting smoothed log data shown in Figure 3.
La Cira Case Study: Upscaling

The inversion results for well 1803 are shown at every 4 ms are plotted versus the two-way travel time in Figure 6a, together with the shale content values given at every 4 ms.

Cross plotting the shale content versus the inversion velocity does not result in any meaningful trend (Figure 7a).

However, smoothing the shale and velocity data in Figure 6a (Figure 6b) shows that the log velocity and the inversion velocity are essentially the same (as should be expected) in this case because the sonic well log serves as the initial velocity model.

Moreover, a meaningful shale content versus velocity trend appears if these smoothed data are cross plotted (Figure 7b). This trend is precisely the same as obtained from the smoothed log data shown in Figure 5.

Figure 6. Well 1803. a. Shale content, velocity inversion (red) and velocity from well log shown at every 4 ms versus two-way travel time. b. Same data, smoothed.

Figure 7. Well 1803. a. Shale content versus velocity inversion based on the Figure 5a data. b. Shale content versus velocity inversion based on the smoothed data from Figure 5b (black) with superimposed trend from Figure 4.
Let us now consider well 1865 where a good shale content log is available, but the sonic data are poor (for this reason, well 1865 has not been used as an initial velocity model for seismic inversion).

The inversion velocity for well 1865 is shown versus the two-way travel time in Figure 8a, together with the shale content at every 4 ms. Some correlation between the inversion velocity and the shale content is apparent. However, this correlation does not result in a clear shale content versus velocity trend (Figure 9a). Smoothing the data with a running mean average improves the correlation (Figure 8b). Cross plotting places the resulting shale content versus velocity trend on top of the trends obtained for well 1803.

Simple smoothing can take care of carrying a rock physics relation from the log to seismic scale.
To develop a rock physics model that links porosity, mineralogy, pressure, and pore fluid bulk modulus to the elastic rock properties, use well log data from La Cira well LC-1880. Consider an interval between 885 and 915 m (Figure 1) where two up-fining depositional cycles are highlighted in the GR track.

Velocity is plotted versus porosity for Cycle 1 and Cycle 2 in Figure 2. The curves in these two plots come from the uncemented (friable) sand model. We can see that as the clay content in the rock increases, the data points move from the clean-sand line to the shaly-sand line. Although the GR values are about the same in Cycles 1 and 2, the model line that describes the shaly part of Cycle 2 requires more clay as input than in Cycle 1. This modeling result is consistent with the core description that states that the shaly part in Cycle 1 is siltstone whereas that in Cycle 2 is claystone.

Figure 1. Well LC-1880. Two up-fining cycles chosen for rock physics modeling. Cycle 1 on top and Cycle 2 below.

Figure 2. Well LC-1880. Two up-fining cycles chosen for rock physics modeling. Cycle 1 (left) and Cycle 2 (right). Velocity versus porosity, data and model lines. The data are color-coded by GR values. The model curves are for 100% water saturation (we assume that the sonic data come from the mud-filtrate-invaded zone). The differential pressure used in the model is 12 MPa. Mineralogy used in the model is given in the plot.
La Cira Case Study: Production Monitoring

(2) Rock Physics Model for Fluid Identification

The well log Vp is plotted versus Vs in Figure 3. The data points are color-coded by water saturation. The data that correspond to oil-saturated reservoir sand fall in between two theoretical curves computed for 100% water and 100% oil saturation, respectively. The five different empirical Vp versus Vs lines also separate the water-saturated from oil-saturated data. The advantage of the theoretical treatment of the fluid detection problem is that one can explicitly specify the reservoir conditions and pore-fluid properties that is not straightforward in empirical relations. A similar plot for core data from well LC-1882 is given in Figure 4. The friable sand model allows for pore-fluid detection in LCI.
La Cira Case Study: Production Monitoring

(1) Production History in Producing Intervals

Well LC-1882 was completed in Zone C with open-hole well log measurements, including monopole sonic, collected in 1988. Seven years later, Zone C in this well was closed, and new cased-hole monopole and dipole sonic logs were recorded. A new interval (La Cira Sands) above Zone C was open for production (Figure 5).

In Figure 6 we plot shale content, the Vp/Vs ratio, and Vp versus depth for Zone C sands from the early (1988) and recent (1995) measurements. Superimposed on the Vp/Vs track are two model curves, one for 100% water and the other for 100% oil saturation. The intervals where the Vp/Vs data curve falls in between the two theoretical model curves (for 100% water and 100% oil saturation, respectively) correspond to the completed hydrocarbon-bearing intervals from which oil was produced between 1988 and 1995.

In the Vp track, a drop in the velocity is observed between the years 1988 and 1995. The observed difference, and, in general, small velocity values, also tie in well with the intervals open for production. The observed large Vp decrease in some of the intervals is most likely due to the addition of free gas to the original fluid system as the reservoir pressure falls below the bubble point. Notice that the intervals with free gas correspond to those where the 1995 Vp/Vs data fall below the 100% oil saturation curve.

Figure 5. Production rate versus time for well LC-1882. Large increase in production in 1995 is due to the opening of the La Cira Sands interval.

In Figure 6 we plot shale content, the Vp/Vs ratio, and Vp versus depth for Zone C sands from the early (1988) and recent (1995) measurements. Superimposed on the Vp/Vs track are two model curves, one for 100% water and the other for 100% oil saturation. The intervals where the Vp/Vs data curve falls in between the two theoretical model curves (for 100% water and 100% oil saturation, respectively) correspond to the completed hydrocarbon-bearing intervals from which oil was produced between 1988 and 1995.

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Figure 6. Well LC-1882, Zone C, interval open to production. (a) Shale volume versus depth with bars indicating completed intervals. (b) Vp/Vs ratio versus depth. The red and blue curves are from our model for 100% water and 100% oil saturation, respectively. The black data curve is from the 1995 data. The part of the data curve that falls below the 100% water saturation curve is shown in gray. (c) Vp versus depth. The black and the red curves are for the 1988 and 1995 data, respectively.
La Cira Case Study: Production Monitoring

(1) Production History in Producing Intervals

The same hydrocarbon indicator technique is applied to the La Cira Sands interval that was closed to production (Figure 7). As expected, the repeated Vp data show no temporal changes. At the same time, the Vp/Vs ratio in the data clearly delineates (by falling between the two model lines) the intervals that were chosen for completion independently, based on the open-hole resistivity data (see water saturation in the first frame of Figure 8). The large production rate increase shown in Figure 6 after 1995 is due to oil production from these intervals.

CONCLUSION

The case study based on LCI data shows that first-principle-based theoretical rock physics modeling can be used to interpret P- and S-wave well log data for hydrocarbon detection behind the casing in fluvial Tertiary sands. The same rock physics approach should be valid for identifying hydrocarbons in LCI and other fields with similar geologic setting from surface seismic if pre-stack or offset-stack data are available. The rock physics interpretation of dipole sonic logs appears to be a promising methodology for the detection of bypassed and untapped oil, and pay intervals behind the casing in mature fields such as LCI.

Well log data also show that a noticeable change in Vp can be expected in produced intervals. Such changes, combined with rock physics interpretation can be a basis for seismic reservoir monitoring.
APPENDIX: Vp/Vs Relations for Fluid Detection

Typically, these relations calculate Vs from Vp in water-saturated rock. It is assumed that if the measured Vp falls below the Vp versus Vs line, rock has hydrocarbon

The shear-wave velocity (or the shear modulus) is a necessary input parameter for full waveform elastic modeling of the seismic response. Some of the rock physics models discussed here provide both bulk and shear modulus.

However, our experience shows that the shear-wave velocity theoretical curves often do not match the data (given that the rock physics diagnostic has been done using the compressional modulus). For this reason, we present here Vp/Vs relations to be used for calculating Vs from the compressional-wave data (or theoretical curves).

1.1. Castagna et al. (1993) Mudrock Equation:

\[ V_s = 0.862V_p - 1.172 \text{ km/s} \]

This equation has been derived from in-situ data for water-saturated shales. The common saturation fluid here is formation water.

1.2. Castagna et al. (1993) Equations for Limestones and Dolomites:

Limestone: \[ V_s = -0.055V_p^2 + 1.017V_p - 1.031 (\text{km/s}) \]

Dolomite: \[ V_s = 0.583V_p - 0.0789 (\text{km/s}) \]

Both equations are based on laboratory measurements conducted on water-saturated samples. The common saturation fluid has to be selected accordingly.

1.3. Krief et al. (1990):

\[ \frac{V_{p-sat}^2 - V_{f}^2}{V_{s-sat}^2} = \frac{V_{p-mineral}^2 - V_{f}^2}{V_{s-mineral}^2}, \]

where \( V_{p-sat} \) and \( V_{s-sat} \) are the compressional- and shear-wave velocity in the saturated rock, respectively; \( V_{p-mineral} \) and \( V_{s-mineral} \) are the compressional- and shear-wave velocity in the mineral phase of the rock, respectively; and \( V_f \) is the velocity in the fluid.
Vp/Vs Relations for Fluid Detection

1.4. Greenberg and Castagna (1992) Method: This empirical formula (below) is based on a number of datasets where ultrasonic velocity measurements were conducted on pure water (the common saturation fluid) saturated rocks.

To calculate \( V_s \) from \( V_p \) for other fluids use Gassmann's equation.

\[
V_s = \frac{1}{2} \left[ \left( \sum_{i=1}^{4} X_i \sum_{j=0}^{2} a_{ij} V_p^j \right) + \left( \sum_{i=1}^{4} X_i \left( \sum_{j=0}^{2} a_{ij} V_p^j \right)^{-1} \right)^{-1} \right], \sum X_i = 1;
\]

where \( X_i \) is the volume fraction of pure mineral constituents in the mineral phase with "1" standing for sandstone (quartz); "2" for limestone (calcite); "3" for dolomite; and "4" for shale. The empirical coefficients \( a_{ij} \) are tabulated below:

<table>
<thead>
<tr>
<th>( i )</th>
<th>Mineral</th>
<th>( a_{i2} )</th>
<th>( a_{i1} )</th>
<th>( a_{i0} )</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Sandstone</td>
<td>0</td>
<td>0.80416</td>
<td>-0.85588</td>
</tr>
<tr>
<td>2</td>
<td>Limestone</td>
<td>-0.05508</td>
<td>1.01677</td>
<td>-1.03049</td>
</tr>
<tr>
<td>3</td>
<td>Dolomite</td>
<td>0</td>
<td>0.58321</td>
<td>-0.07775</td>
</tr>
<tr>
<td>4</td>
<td>Shale</td>
<td>0</td>
<td>0.76969</td>
<td>-0.86735</td>
</tr>
</tbody>
</table>

1.5. Williams (1990) Method:

\[
\begin{align*}
V_p / V_s &= 1.182 + 0.00422 \Delta t_s \quad \text{Sands}, \\
V_p / V_s &= 1.276 + 0.00374 \Delta t_s \quad \text{Shales},
\end{align*}
\]

where \( \Delta t_s \) is in \( \mu s/ft \).

To convert the Williams equations into another form, we use \( \Delta t_s = 304.8 / V_s \), where \( V_s \) is in km/s. Then we have

\[
\begin{align*}
V_s &= 0.846 V_p - 1.088 \text{ km/s} \quad \text{Sands}, \\
V_s &= 0.784 V_p - 0.893 \text{ km/s} \quad \text{Shales}.
\end{align*}
\]

Compare this to Castagna's mudrock line: \( V_s = 0.862 V_p - 1.172 \text{ km/s} \).

These equations can be also re-written to express the Poisson's ratio through \( V_s \). For example, for the Williams Sandstone equation we have:

\[
\frac{V_p}{V_s} = 1.182 + \frac{1.29}{V_s}, \quad \nu = \frac{1}{2} \left( \frac{V_p}{V_s} \right)^2 - 2.
\]
Vp/Vs Relations for Lithology Prediction
EXAMPLE: MARLS

![Graph showing Vp/Vs relations for different lithologies.]

- Mudrock Line
- Williams Shale
- Limestone Curves

- Well A
- Well B