"Do No Harm!" – Seismic Petrophysical Aspects of Time-Lapse Monitoring

Wayne D. Pennington, Michigan Technological University

Summary

Time-lapse seismic studies of oil and gas reservoirs depend on understanding the seismic response to changing reservoir conditions. By providing erroneous predictions, however, geophysicists have the ability to actually harm future production.

The steps involved in time-lapse seismic petrophysical modeling are simple; the details, however, are imposing. To predict future reservoir seismic response accurately, one must know the future reservoir conditions that may be encountered, including: changes in fluid saturation; changes in the properties of the fluids themselves; changes in the dry-frame moduli; and changes in the whole-rock response (usually modeled by Gassmann theory).

Simple applications of the modeling procedure described above can lead to highly misleading interpretations of time-lapse seismic observations; extreme care must be taken to include all appropriate parameters and to model the response correctly.

Introduction

If the predictions made for the seismic response of a given producing reservoir are in error, the interpretation of a time-lapse survey will be incorrect. This, in turn, may provoke implementation of a production scenario that is worse than one that *would* have been performed if the time-lapse survey had never been conducted. Geophysicists may need to adapt the code of physicians: "First, do no harm." Because geophysicists have the capability, not only of assisting production scenarios, but also of harming them, it is imperative that they become familiar with the seismic petrophysical aspects of time-lapse monitoring of oil and gas reservoirs.

We can avoid harm by being extremely careful in each and every step of the seismic petrophysical modeling procedure. This paper describes, using two typical reservoir rocks and initial conditions, the following modeling approaches, in sequence:

- a simplistic modeling approach, applying Gassmann's theory directly as gas comes out of solution;
- a more careful approach, in which we correct the log data for invasion;
- a complete approach that includes the above steps, but also uses published values for the change in dry-frame moduli as effective pressure increases;
- finally, an identical approach, but assuming some of the gas migrates away from the portion of the reservoir under consideration.

The seismic responses to the various scenarios are different for the different rock types and starting conditions, as expected; but they are surprisingly sensitive to the completeness of the modeling procedure, and to the specific relationships used.

Original Formation Conditions

For the purposes of this study, we will assume two different reservoir rocks under different reservoir conditions; these rocks and conditions are designed to closely model a set of reservoirs that are a subject of a detailed study in the Gulf of Mexico, and are in no way pathologically unique. Both are highly porous sands, under conditions which will tend to maximize the points we wish to make in this paper.

<u>Reservoir A (overpressured):</u>

- Depth .... 5600 ft 1706 m
- Temperature ....139° F 59° C
- Pressure ....3700 psi 25.5 MPa
- Pressure gradient ..... 0.66 psi/ft 14.9 kPa/m
- Oil Gravity .... 37°API
- GOR .... 970 scf/stb 173 l/l
- Logged Vp .... 7350 ft/s 2240 m/s
- Logged density .... 2.03 g/cc

<u>Reservoir B (normally pressured):</u>

- Depth .... 4500 ft 1372 m
- Temperature ....130° F 54° C
- Pressure ....2000 psi 13.8 MPa
- Pressure gradient...... 0.44 psi/ft 9.95 kPa/m
- Oil Gravity .... 28° API
- GOR .... 340 scf/stb 61 l/l
- Logged Vp .... 10500 ft/s 3200 m/s
- Logged density .... 2.14 g/cc

Notice that Reservoir A consists of an overpressured, under-compacted sand, while Reservoir B hosts a normally pressured, normally compacted sand. For the purposes of this exercise, we will assume that the logged Vp/Vs ratio is 2.0 (Poisson's ratio is 0.33) in each reservoir. We also assume the overlying shale is higher velocity and higher Vp/Vs. Neither reservoir had free gas at time of discovery.

Check for Internal Consistency of Fluid Parameters

First, we want to make sure that our input values are sensible, and not surprising. We check the GOR observed for the oils in each reservoir, and compare those with the predicted maximum (saturated) GOR from the empirical relations of Batzle and Wang (1992); we find that they agree very closely. From this, we can infer that the reservoirs are indeed saturated, and that production resulting in a decrease in pressure is likely to produce free gas very quickly. Many Gulf of Mexico oil reservoirs are saturated, even though they contain no free gas on discovery; the simple conclusion is that the gas that has evolved, over geologic time, from these reservoirs has long since escaped through imperfect seals. In this situation, then, it is not surprising that the overpressured reservoir contains the oil with the higher GOR – gas has evolved and escaped over geologic time from the normally pressured Reservoir B, but it has not evolved from the overpressured Reservoir A, and remains in solution there.

A Disclaimer Concerning Saturations

Several assumptions are required to complete the models. These will be explained as we encounter them, but none of them are 'rigged' to make the results fit a certain set of conclusions. In order to model the evolution of each reservoir precisely, we would need to know and understand the drive mechanisms, the relative permeabilities, and other parameters that will, for this exercise, be ignored.

Instead, we will assume that the percentage of pore volume occupied by gas increases by 10 percentage points for every decrease of 300 psi in reservoir pressure until it reaches 50% gas saturation. Whether or not this is reasonable depends on many things, including the time scale of production. For example, if the reservoir pressure is slowly drawn down, and the relative permeability to gas sufficiently high, a gas cap will form and increase the gas saturation at the top of the reservoir, where we are most interested in the seismic properties. On the other hand, if vertical permeability is low, or the reservoir is drawn down rapidly by production, the gas may not have moved, and the seismic response corresponds to a lower gas saturation. Yet again, gas may be produced more rapidly than oil due to its higher relative permeability, and the gas remaining in pore spaces would be lower than assumed.

In the absence of reservoir modeling, we are making the simple assumption that gas saturation correlates directly with pressure decline for the purposes of this exercise alone.

Remaining Oil Phase 'Stiffens'

In all of the scenarios, we recognize that as gas comes out of solution, the remaining oil phase has a lower GOR, and increased bulk modulus; that is, the remaining oil has become 'stiffer' as the gas is removed from solution. We use Batzle and Wang's (1992) relationships to predict the properties (GOR and bulk modulus) of the oil phase. Comparisons with PVT analyses on a fluid sample taken from one of the reservoirs confirm the applicability of these relationships.

Naïve Model

In the first model, we simply take the values as provided, solve for the dry-frame moduli using Gassmann's equation, and then solve Gassmann's equation again, assuming gas has come out of solution (as the reservoir pressure declined during production) to occupy varying percentages of the pore volume. We also assume the log values represent the formation conditions, where Sw=0.3 (irreducible water saturation) in order to obtain the dry-frame moduli (including a dry-frame Poisson's ratio) for each reservoir. Then we substitute gas for oil (but not water) in the pore space, and solve Gassmann's equation for the reservoirs. We obtain the following velocities and Poisson's ratios.

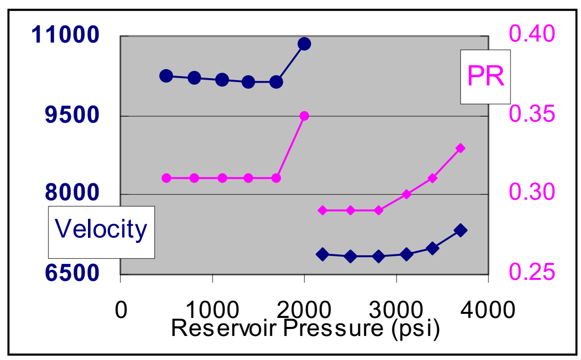

Figure 1: The predicted seismic properties as the reservoir is produced under this simple model. Diamond symbols represent Reservoir A and circles represent Reservoir B. The thinner curves use the PR (Poisson's Ratio) axis; the darker curves represent Velocity (ft/s).

We also find the bulk densities and impedances shown in Figure 2. As we might have expected, in both reservoirs we predict a brightening of the reflection and an increase in the AVO response as the reservoir is produced.

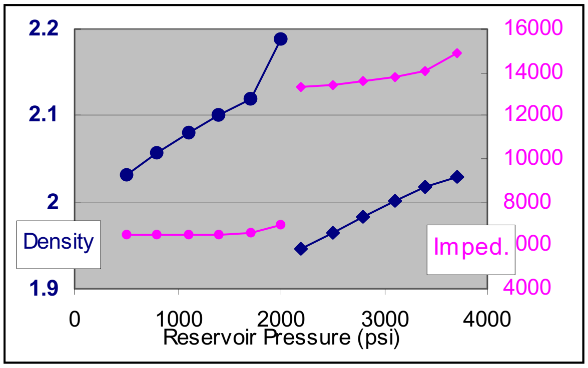

Figure 2: The predicted densities and impedances from the simple model. Darker lines represent density (g/cc), and the lighter lines represent impedance (in ft/s * g/cc).

Correct the Log Data for Invasion

In this model, we realize that the log data we are using represents an invaded zone, and not the true reservoir conditions. We first must ‘correct’ our velocities and Vp/Vs ratios to the reservoir conditions, again using Gassmann’s equation and simple fluid substitution (and assuming homogeneous saturation, not ‘patchy’). This time, we assume that the logged conditions represent 30% oil (residual oil saturation) and 70% brine (invaded mud). We then arrive at the following production scenario (the differences in densities from those computed in the simple scenario are small, and not shown):

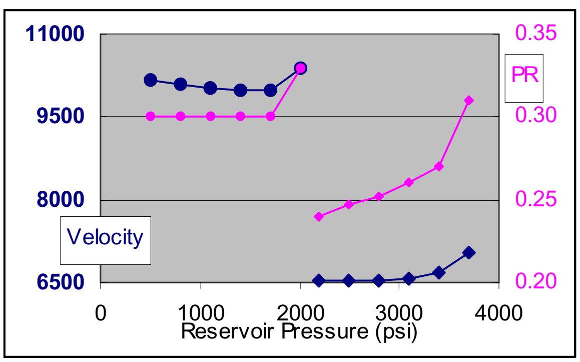

Figure 3: The velocities and Poisson’s ratios (PR; note scale change) for the two reservoirs, with the assumption that the logged values represented invaded conditions.

There are some differences to be noted between the results predicted for this model, and the one in which we assumed the logged values represent formation conditions, but they are not enough to cause us alarm.

Dry-Frame Moduli Increase

The next scenario builds on the last, and further assumes that the frame of the rock ‘stiffens’ as the reservoir pressure decreases. That is, we account for the stress-dependence of velocities in the rock framework; this is usually expressed in terms of changes in the dry-rock or dry-frame moduli as they are used in Gassmann’s equation. For the purposes of this exercise, we will use a set of relations developed by L. Bentley and colleagues (personal communication, 1999), for which we have calibrated some of the constants using the properties of these specific reservoirs. We obtain the following results:

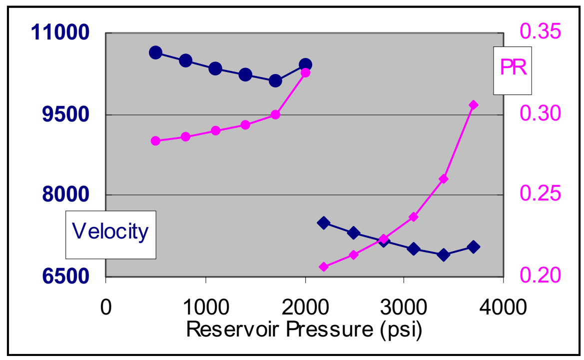

Figure 4: Velocities and Poisson’s Ratios for model in which the dry-frame moduli of the formation rock changes with increased effective pressure during production.

Notice that the bright-spot effect from the gas has been overwhelmed by the stiffening effect of the dry frame in both reservoirs. It is important to realize that the specific relationship used for the dry-frame stress sensitivity will very strongly determine the degree to which the gas-effect may be overcome.

If the Gas is Produced or Migrates Away

In the above scenarios, we always assumed that the gas did not migrate away from the volume element of the reservoir in which it was released. But this is rarely the case, once a critical gas saturation has been reached and the gas becomes mobile. The gas typically exhibits a greater mobility than the oil or water after it reaches some saturation, and moves readily throughout the reservoir, upwards (gravity segregation) and/or toward a producing well. In the event that all of the gas has moved away from a particular location in the reservoir, leaving only a residual gas saturation (taken here to be 0.1), the following conditions are predicted:

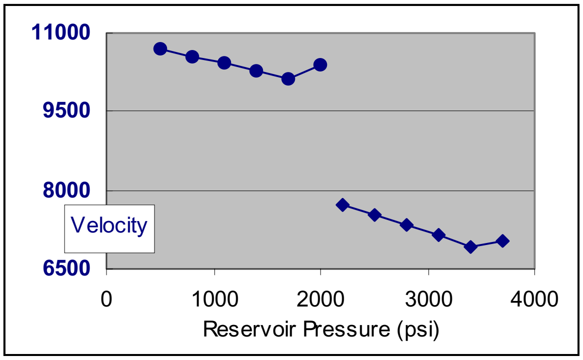

Figure 5: The velocities (Poisson's ratio is not shown) for the scenario in which gas is liberated and remains in the local part of the reservoir until it exceeds 0.1 saturation, after which all gas in excess of 0.1 moves away, either updip or to a producing well.

Summary and Conclusions

Figures 6 and 7 summarize all of the velocities observed in the preceding scenarios. We observe that an assumption of simple fluid substitution (either the 'naïve scenario' or the 'corrected for invasion' curves) will lead to extremely optimistic predictions for reservoir monitoring, whereas the more-complete scenarios, including dry-frame stress effects and migration of gas, will likely result in considerable ambiguity for interpretation of time-lapse seismic observations.

Only when performed in conjunction with careful reservoir modeling, and only after including all the seismic petrophysical effects likely to be important, can the reservoir geophysicist be confident that his or her predictions are valid, and are likely to 'do no harm.'

Acknowledgments

This work was supported by a contract from the U.S. Department of Energy through their National Petroleum Technology Office in Tulsa, Oklahoma, DE-AC26-98BC15135, "Calibration of Seismic Attributes for Reservoir Characterization," under project manager Purna Halder. Discussions with Josh Haataja, Terra Bulloch, Randy McKnight, and Lawrence Bentley contributed significantly to the thoughts presented here.

References

Batzle, M. and Wang, Z., 1992, Seismic properties of pore fluids, GEOPHYSICS, **57**, 1396-1408.

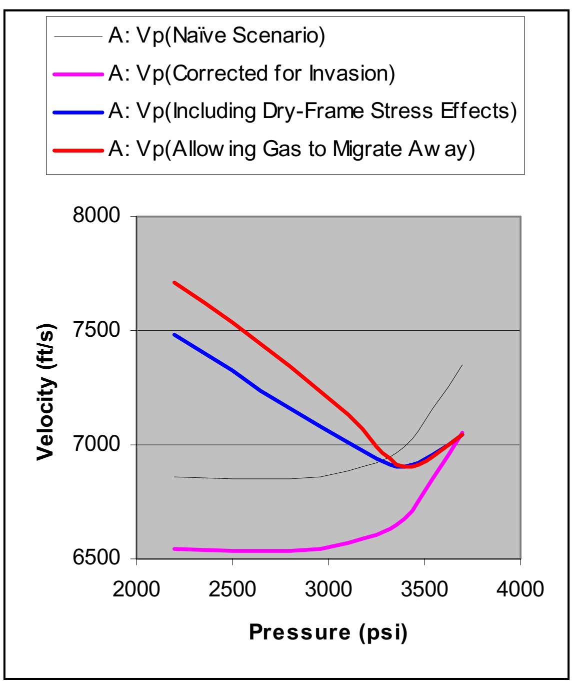

Figure 6: Reservoir "A" summary.

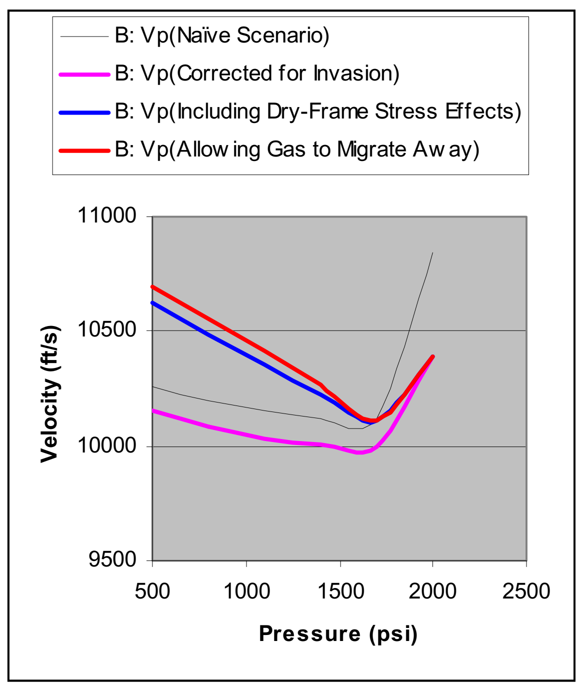

Figure 7: Reservoir "B" summary.