The second question we selected was on how to make a distinction between low-saturation gas and commercial gas reservoirs, and include the answer given by Reinaldo Michelena (SeisPetro Geoconsulting, Denver, USA). We thank Reinaldo for his response. Readers are encouraged to send us their feedback and even the questions they would like to get answered by experts.

- Satinder Chopra

Q. How is it possible to meet the challenge of distinguishing 'fizz gas' from 'commercial gas' sand units in the subsurface using seismic and borehole data?

Expert answer by Reinaldo Michelena*

Addressing the issue of non-unique seismic interpretations

Before digging into the question of differentiation between commercial and residual gas using seismic data, let's first discuss the fact that the interpretation of seismic anomalies can often be non-unique. In these cases, a significant effort may be required to minimize the non-uniqueness and manage the associated risks. Ideally, interpreters would like to use attributes whose interpretation yields unequivocal results, like a seismic horizon or a fault in a simple structure, but this is not always the case. When two rock types A and B show a similar response in one attribute (e.g., acoustic impedance), we typically need to use another attribute (e.g., V_P/V_S ratio) that responds to other properties of A and B. Then, with the help of well log data, we check whether A and B can be differentiated. The extraction of certain seismic attributes may require more effort than others or may require data not commonly acquired. In addition, since interpreters should be working in integrated asset teams with common goals, they should also search for other means to solve critical asset problems that may go beyond seismic data and may require a more comprehensive understanding of the geology of the problem (geology matters!) or even an understanding of other disciplines and data.

Now, going back to our initial question, the general workflow to differentiate residual gas ("fizz gas") from commercial gas is no different from other workflows we apply if we want to separate a target rock from the background when both have a similar seismic response.

The first recommendation in the differentiation recipe is that if using one attribute alone doesn't differentiate rock A from rock B, we should investigate the rock physics relations to find another independent attribute that can contribute to the differentiation. Occasionally, some interpreters don't follow this advice, and this is where problems start.

Commercial or residual gas: what experts have recommended in the past

Many bright amplitude anomalies have been successfully drilled over the years, but the consensus is that the drilling results are a mixed bag of good and disappointing, costly findings. Even though the pitfalls of chasing

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bright amplitudes as the only criteria to select drilling locations for gas have been well documented (they only serve to detect the presence of gas but have no relation with the actual gas saturation, or they may be indicating simply tuning effects, or it may be related to brine saturated porous rocks, etc.), the convenience of using a single attribute seems to have overweighted in some cases the risks associated with that practice.

In 2004, Dr. Satinder Chopra invited a group of rock physics experts to write for the *Recorder* of the Canadian Society of Exploration Geophysicists (CSEG) their answer to the same question he is bringing to our attention today, that is, distinguishing residual gas and commercial gas saturations. These experts gave their opinions and provided recommendations that remain current today, but now some of these recommendations are easier to implement because of advances in seismic data acquisition and processing.

The selection of the independent attribute should be guided by petrophysics and rock physics analyses. In this regard, the four experts that contributed to the 2004 *Recorder*'s article pointed towards rock density as a critical parameter. The reason is that, unlike compressional velocities that are significantly affected by the addition of a small amount of gas, the relation between density and gas saturation is linear. Back in 2004, inverting for density was rare because most data sets didn't have the required offset information to capture curvature (or "third term") variations in the AVO response.

Enhanced technologies allow better implementation of known solutions

Seismic recording technology, however, has advanced significantly in the last 20 years to the point that the old rule of thumb in survey design of a ratio Offset/Depth (O/D) equal to one has improved to O/D ≈ 1.3 or 1.4 for imaging purposes, and much larger for velocity estimation. Unfortunately, the acquisition of longer offsets hasn't resulted in more use of density inversions that rely on those offsets. Many interpreters got used to the idea that density inversions were not of good quality because of the "lack of offsets", so they didn't even try to perform such inversions under any circumstance. Furthermore, even if the right offsets are now available, some interpreters don't even look at the density inversions coming from recently acquired data because they think densities are intrinsically unreliable. In my personal experience, after years of working with seismic data, I have found that independent density inversions can yield useful results, even without the ideal offset range, so I always try before discarding the inversion based on "theoretical" grounds. This means that, besides offsets, the nature of density contrasts also plays a role. Hopefully, seeing more and more case studies with good-quality density inversions will help to change this perception. Another issue to keep in mind when using density is that the porosity variability must be well understood too, since both porosity and gas saturation contribute to bringing the density down.

If density cannot be extracted by itself, examining any density related attribute may provide useful insights. This is the case for the PS reflectivity, which is mostly sensitive to changes in density and S wave velocity. Although the estimation of PS reflectivity (or PS impedance, if inversion is performed) requires the recording of multicomponent data, it turns out that the density information is contained in the near offset PS conversions, which may prove useful when recording long offsets is not possible or when near offset 3C VSP data is available. By analyzing PS reflections, it should be possible to explain the reasons for the strong amplitude anomalies observed in conventional PP data: weak PS reflections may indicate residual gas in the interval of interest, whereas strong PS reflections may indicate commercial gas.

In the absence of long offset PP or near offset PS data that facilitates the estimation of density, using conventional *inverted* attributes such as Lambda*Rho, Mu*Rho, or even spectral decomposition to look for areas of decreased wavelength due to the presence of gas are better alternatives than using raw poststack amplitude or AVO attributes alone, in particular when calibration data from different wells is available and more reliable correlations can be established. Modeling the seismic response for different “what-if” scenarios can help understand the sensitivity of different attributes to changes in saturation.

When seismic if not enough, use other concepts and technologies

A less common but powerful tool that can be used to assess fault conductivity is the estimation of mechanical slip potential along the fault planes. Faults segments prone to slip (or critically stressed) will also be more prone to conduct fluids than mechanically stable fault segments which are usually closed. This kind of analysis on the fault planes requires geomechanics concepts and data such as the local stress state, fluid pressures, and rock properties in the vicinity of the faults.

The task of the geophysicists is to help the asset team solve the problem of separations of commercial and residual gas, even if the method they propose is not seismic related. This is the case of the control source electromagnetic (CSEM) method. The result of CSEM acquisition and processing is a volume of resistivity that is related to gas saturation: high resistivity indicates higher gas saturation and vice versa. CSEM can be extremely useful in early exploration stages. This method has matured considerably in the last 20 years and is now commercially available by various vendors. The main drawback of the CSEM method is its low lateral and vertical resolution, resulting in anomalies that may not be properly collocated with seismic anomalies, and making the joint interpretation tricky. Besides, different inversion algorithms may yield different results and structural changes can add another level of complexity to the analyses since dip changes may affect the response. Even with these weaknesses, the presence of resistivity anomalies can be a strong indication of higher gas saturations that can help rank potential gas saturated zones that have been detected with seismic amplitudes. In any case, CSEM data must be used in conjunction with seismic data, either for qualitative joint interpretations or for constrained inversions that use the seismic derived information for better definition of the resistivity anomalies. In addition, but less common, joint inversion of seismic AVO and CSEM data can also be performed, but this requires rock physics models that related elastic and electrical properties.

A recipe for starters

In summary, the recipe to differentiate residual gas from commercial gas is no different from the recipe we use to differentiate rock types using seismic data. We should keep in mind that seismic interpreters should not work in isolation from other disciplines and data, and the final goal is to reduce risk for the asset. Having said this, here is a checklist:

- Understand the geologic context: Where does the gas come from? How is it trapped?
- Acquire the data needed to extract density-related attributes: long offsets PP data or PS converted waves data.
- Detect the gas first. Make sure the seismic anomalies are gas related.
- Estimate density or density related attributes.
- Rank amplitude anomalies based on density (or gas saturation).
- Use interval attributes (from prestack inversion or spectral decomposition) instead of raw amplitudes.

- Calibrate seismic attributes with gas saturation from petrophysical evaluations in a "sufficient" number of wells. Local, careful analyses of inversion results with log data can go a long way in reducing risk. Probabilistic facies mapping can be helpful at this stage after commercial and residual gas facies have been identified at well locations.
- Interpret faults in the seismic data.
- Model fault juxtaposition and use geomechanics concepts and data to assess fault conductivity and compartmentalization.
- Rank possible gas traps based on fluid conductivity of surrounding faults.
- Use CSEM data to assess gas saturation. Enhance the resolution of CSEM results by incorporating the structure interpreted from seismic data. Model different resistivity scenarios to help explain observations.
- Make sure all interpretations are consistent among data types and disciplines. G

Acknowledgement

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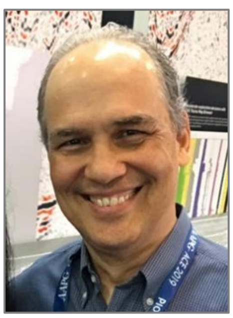

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